

Choice of development concept – platform or subsea solution?

Implications for the recovery factor¹

by

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A real choice exists today on a number of discoveries between platform-based or subsea development solutions. Statistics from the Norwegian continental shelf (NCS) show that fields developed with fixed platforms have a substantially higher recovery factor. The potential for a later commitment to improved oil recovery (IOR) is determined largely by the original development solution. Through the use of cases and examples, this article discusses the valuation of the enhanced flexibility offered by platform-based development solutions. It illustrates that valuing the various types of flexibility is difficult, which leads to the following question – are development solutions being selected without taking sufficient account of option values?

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1. Introduction

Technological progress with subsea production has been rapid. Such installations can now be utilised in most conditions, and costs have been sharply reduced. A real choice exists today on a number of discoveries between platform-based or subsea development solutions. Where the distance to land or to existing platforms is short, in particular, a subsea facility could be a good answer for fields with small resources or in deep water. The choice of concept is a complex business, with input from many interested parties and technical disciplines.

Examples of key developments on the NCS which faced a demanding choice of concept are Ormen Lange and Snøhvit in the Norwegian and Barents Seas respectively. These fields have been developed with subsea solutions even though that has required long tie-backs to land-based terminals. Platforms were one alternative studied.

Investment in subsea installations is lower, but drilling costs remain high throughout the field's producing life, and licences may often have to pay tariffs to infrastructure owners.³ Fixed platforms offer a number of advantages, which need to have a value put on them. Such installations permit a flexible drainage strategy, particularly if the platform has its own drilling facilities. They offer lower marginal costs for IOR campaigns after a few years of learning lessons on the field, and they normally have higher regularity over their producing life. New recovery technology which emerges after development has ended is often easier to adopt when a platform has been chosen.

The recovery factor is defined as the proportion of the oil in a reservoir which is recovered. A key concept in this context is *stock tank oil originally in place* (Stooip). "Stock tank" is the volume at normal pressure and temperature. Stooip must not be confused with oil reserves, which are the volume which can be technically and commercially recovered.⁴ The recovery factor for offshore oil fields normally lies between 10 and 60 per cent, but can reach close to 80 per cent in certain favourable cases.⁵

³ In other cases, the same partners own both the subsea field and the processing facilities – as with the Ormen Lange and Snøhvit examples mentioned. If, as in these cases, the development involves a tie-back of subsea facilities to a newly built land-based terminal, this will be included as investment in the net present value calculations. When, on the other hand, the choice is to tie back to an existing processing facility owned by the licence – which could now or over time be utilised by other projects (owned by the same licence or others) – an opportunity cost will always have to be calculated for use of the capacity.

⁴ Osmundsen (2010).

⁵ US Department of Energy (2008).

Approved oil company plans at the end of 2010 would mean that 54 per cent of the oil in fields developed on the NCS remains unrecovered.⁶ Norway has achieved high recovery factors compared with other countries.⁷ Nevertheless, substantial financial gains could be made from improving the recovery factor – an increase of just one per cent in oil production beyond today's approved plans could yield net revenues in the order of USD 20-30 billion at current oil prices.⁸ As always, revenues must accord with costs, but a potential for profitability very probably exists for both government and oil companies.

The development concept is one element which influences the recovery factor, and which offers a choice. Reservoir, fluid and rock properties are more important, but are determined by nature in the same way as porosity, permeability and the quantity of gas dissolved in the oil together with heavier components which can cause wax formation and raise oil viscosity – thereby hampering production. The recovery factor also depends on the efforts made by the oil companies to maintain production over time, including injection of water, gas, chemicals and so forth in addition to well workovers and new drilling. But the choice of development concept has a big impact on the cost of subsequent IOR work. So it is interesting for government and companies to study the validity of decision criteria for concept choice – the extent to which these take account of the relationship between concept choice and recovery factor.

2. Real options in oil recovery

The potential for a later commitment to IOR is determined to a great extent by the original development solution. One based on a dedicated drilling rig, for instance, will normally have greater potential than platforms without such facilities or than subsea solutions where a mobile rig must be chartered each time. This affects not only the flexibility for but also the marginal cost of workovers or new wells.

⁶ IOR expert committee (2010).

⁷ A global overview of recovery factors is provided in Ivan Sandrea and Rafael Sandrea (2007). They report an overall factor of 46 per cent for the North Sea, and describe this as the highest in the world. According to Laherre (2006), the global average recovery factor is 27 per cent. This draws on the most detailed global database, the IHS reports from 2006, which cover some 11 500 fields.

⁸ Interview with Johannes Kjøde at the NPD, *Norwegian Continental Shelf*, no2, 2009, p 6. It is difficult to make accurate cost estimates here, and it is consequently of equal interest to look at the corresponding gross revenue, which is in the order of USD 50-60 billion.

One advantage of subsea installations is lower initial investment. On the other hand, costs are higher for operation and maintenance, tariffs may often have to be paid for processing, flexibility is lost and it is far more expensive to drill new wells or implement necessary changes to existing ones. Installing a platform with drilling facilities makes it easier and cheaper to intervene in wells, run measuring devices, and identify and diagnose improvement possibilities. Opportunities for injection are greater, and more wells can be drilled. It is also simpler and cheaper to implement necessary changes – including alterations to the drainage strategy. An improvement measure on a subsea well often requires five times the earnings potential than would be needed for an intervention in a platform well.⁹ At the same time, a platform solution will provide greater assurance that the position has been understood while providing a better database and lower operational risk, which relates in part to weather conditions (drilling from a platform or a jack-up rig cantilevered over a wellhead installation is seldom halted by bad weather). A platform solution avoids the restrictions on well numbers imposed by a subsea development. Operations can also be optimised regardless of sharply fluctuating rig rates.

The threshold for making changes to subsea wells is often very high. It is possible, for instance, to find oneself in conditions where rig rates are increased for many days because of bad weather. Platform wells also have better production regularity, while mechanical damage can as a rule be repaired and wells brought back on stream in reasonable time. Taken together, these considerations mean that developments based on platforms with their own drilling facilities have a substantially higher recovery factor. This is illustrated by Figure 1.

⁹ Delays to well intervention are one consequence of this. The backlog in well maintenance has led to production losses which cannot be recovered and to the downgrading of reserves. See the IOR expert committee (2010).

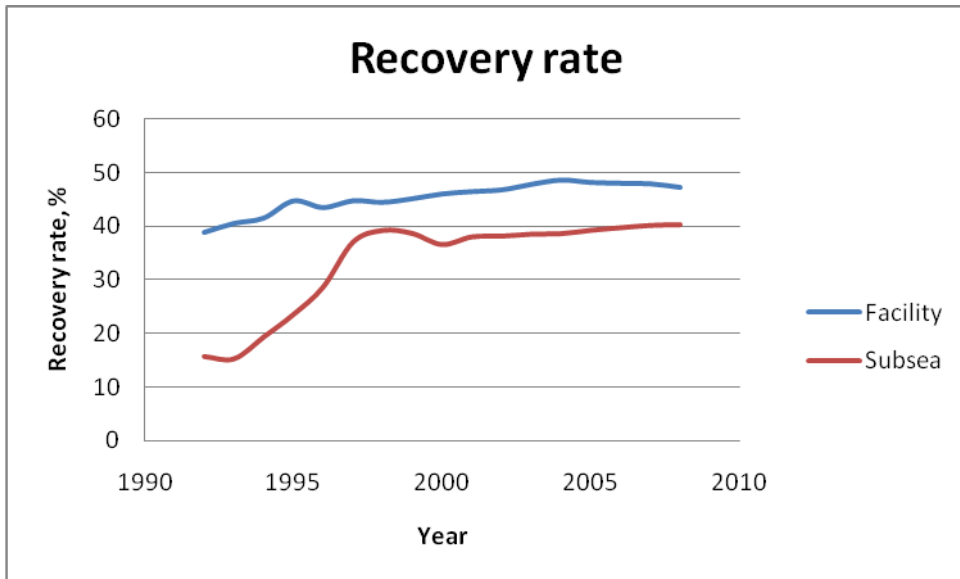


Figure 1. Average recovery factors for fields with platform and those developed with subsea wells. Platforms are defined here as fixed structures with a drilling module. Data source: NPD.

The difference in recovery factor between fields with fixed platforms and those developed with subsea completions equals seven *percentage points*. For fields included in the statistics, this translates into 17 *per cent* higher production on average with a platform.¹⁰

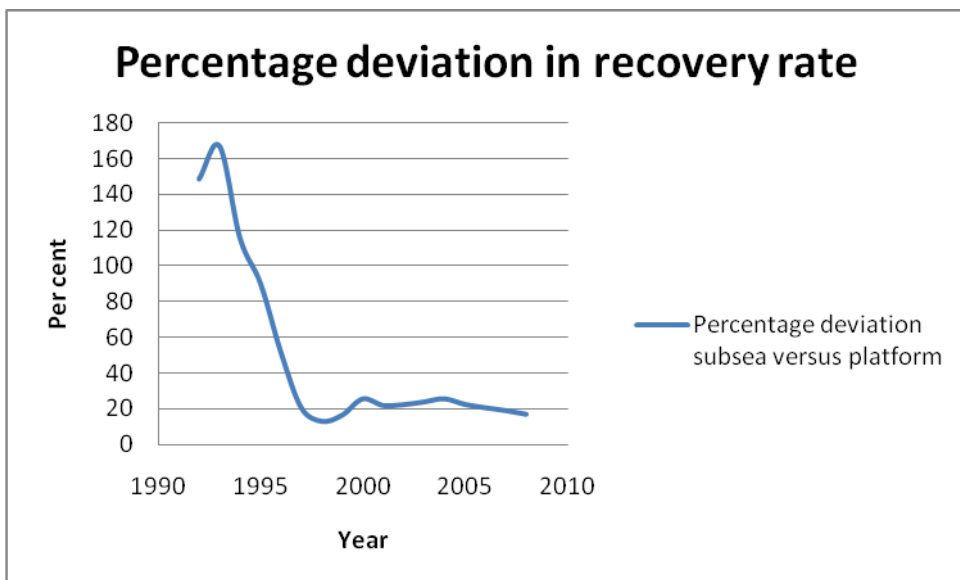


Figure 2. Percentage difference in average recovery for fields with fixed platforms and those developed with subsea completions. Data source: NPD.

¹⁰ The reason for the difference is that, while the recovery factor is calculated in relation to the Stooip, the production increase is calculated in relation to existing output – in other words, the denominator in the latter fraction is substantially smaller.

We can see from Figure 2 that the percentage difference fell sharply until 1998 – when it was 13 per cent – and thereafter flattened out, although with some fluctuations. When using statistics, the possibility of sampling errors must always be borne in mind. Ideally, the recovery factor for different development concepts should be compared for the *same* field. That is not possible. Developments proceed with incomplete information, but the companies know a good deal from interpreting seismic and well data. Since they are often likely to be able to make a concept choice suited to the reservoir, the variation in recovery factor between platforms and subsea completions as shown in Figures 1 and 2 may be somewhat exaggerated.

Real options related to platform-based developments
Flexible drainage strategy
Technical flexibility, greater potential
Financial flexibility, lower marginal costs for extra measures
Lower operational risk
Greater regularity

Table 1. Real options in the choice of concept for offshore petroleum developments – increased opportunities from choosing a platform.

Real option theory is a well-developed discipline which makes it possible to price a number of real options.¹¹ However, the models are not particularly suitable for analysing the real options listed in Table 1. This is partly because the latter are complex, partly because they are not independent, and partly because the option models – which originate in the pricing of securities – build on assumptions which are inappropriate for choosing concepts in petroleum developments.¹² In my experience, existing oil company models fail to pick up all real option elements.¹³ To ensure that all real option effects related to concept choices are included, it could accordingly make sense to use simpler models – such as sensitivity analyses which take account of the differing drilling costs and production volumes related to the various options.

A simple approach to the issue of development with a platform or a subsea solution is to regard this as a classic choice between expenditure today versus tomorrow. A platform-based development involves a higher initial investment, but lower drilling costs and tariff savings

¹¹ A key textbook in this area is Dixit and Pindyck (2004).

¹² See Pilopovic (2007).

¹³ More sources of uncertainty exist than those shown in the table, including the fact that subsea solutions require developments in rig rates to be modelled. Conditions could also arise where production is lost because of rig shortages.

over the field's producing life. However, the difference in cost structure has an additional effect – which represents the main point of this article. This is that lower post-development drilling costs also yield a higher recovery factor and therefore increased revenues. In the following, I will review a simple example which can illustrate the effect on the income side.

3. Example

The financial effect of increased production on the choice of a platform-based development will depend critically on whether the expected increase in volume takes the form of higher on-going output (greater plateau production) or an extended producing life for the field. The first of these effects could be obtained when a development is optimally tailored to the reservoir. Succeeding in that – with the aid of good reservoir understanding and a reservoir which is not too complex – means a high recovery factor can also be achieved with a subsea solution. If, on the other hand, the reservoir is complex and surprises are encountered, the increased flexibility offered by a platform will provide higher plateau production. In other cases, the greater flexibility will primarily be experienced in the field's final phase by allowing its producing life to be extended. Because of discounting, volume increases in the final phase will exert less influence on the net present value.

These effects can be illustrated by a simple calculation. I am assuming here a model field which can produce 100, 150 or 200 million barrels of oil from a platform-based development. Applying the average recovery factor for the NCS in 2008 – 47 per cent for platforms and 40 per cent for subsea completions – means that the corresponding recovery for a subsea solution would be 85, 127 or 170 barrels. A lead time of three years is assumed. For simplicity's sake, the production rise from choosing a platform rather than a subsea solution is assumed to occur on a straight-line basis over 15 years when the increase takes effect in plateau output. When the improvement alternatively comes at the end of the field's producing life, it is assumed to be allocated on a straight line basis over five years, so that the overall production period extends to 20 years. The real discount rate is set at 10 per cent,¹⁴ oil prices at USD 90 per barrel in real terms and the US dollar exchange rate a NOK 6.

¹⁴ Boston Consulting Group (2005) identified required rates of return in oil companies through an interview study. A representative real rate of return was 10 per cent.

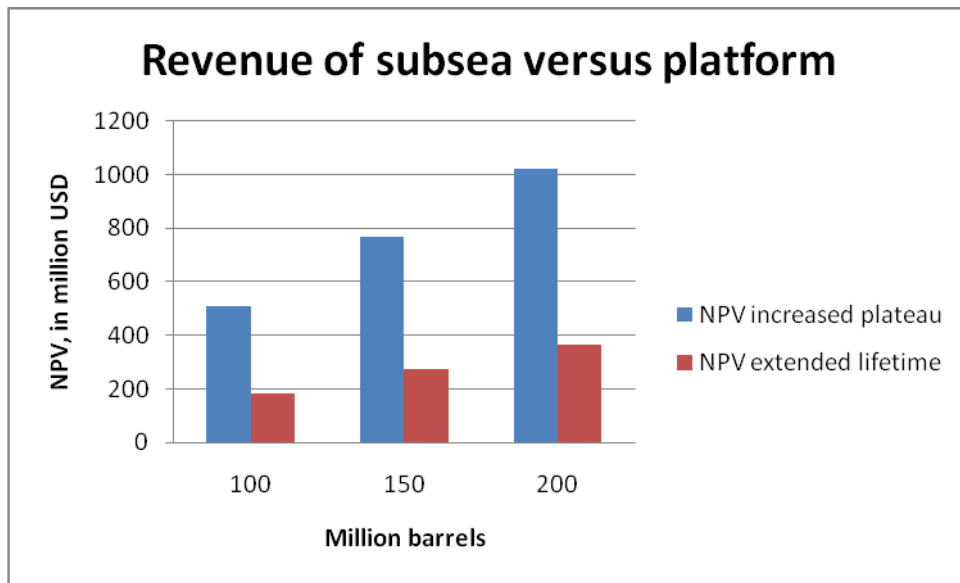


Figure 3: The rise in revenue for a model field measured by net present value, in USD million, for a platform-based versus a subsea development, with total production from the model field of 100, 150 and 200 million barrels.

From Figure 3, we see that the gain in net present value through the rise in volume could be as high as USD 1 billion. This revenue increase is supplemented by the net present value of savings over the field's lifetime from a platform-based development solution. That includes lower drilling costs and tariffs paid to infrastructure owners over the field's whole producing life. The discounted sum of these two effects – higher revenues and saved operating costs – represents the rise in initial investment one should be willing to bear in order to opt for a platform-based solution. Figure 3 shows that this willingness to pay varies substantially with expected reserves.

This is only a rough example. Other assumptions could obviously yield different results. A lower rate of return would boost net present value.¹⁵ The same effect would be achieved by assuming a real rise in oil prices in the time to come.¹⁶ A different production profile, which takes longer to reach plateau, would reduce the net present value somewhat.

The difference in recovery factor between subsea solution and platform is the most important parameter here, and also the most difficult to estimate. By using average figures, I implicitly

¹⁵ Interest rates have fallen substantially since 2005, and are not expected to rise in the near future. That would encourage lower required rates of return.

¹⁶ Cambridge Energy Research Associates (Cera), for example, assumes that oil prices will rise to USD 100 per barrel by 2015: <http://www.cera.com/asp/cda/client/report/reportpreview.aspx?CID=11485>.

assume an arbitrary decision. That is probably incorrect. If the oil companies systematically succeed in making a concept choice tailored to the reservoir, the expected difference between the two development concepts will be lower than average figures for the NCS suggest.

Subsea solutions are often selected because a platform-based development would not be profitable – initial investment is significantly lower with seabed installations. In deep water, a subsea approach is often the only one possible. However, the appropriate solution for many developments is a matter of doubt. Large reserves point towards a platform-based concept because achieving a high recovery factor makes good economic sense. Another factor favouring a platform is a complex reservoir – increasingly common on the NCS. That calls for greater flexibility. In such a case, a subsea facility would mean high operating costs in the form of new wells and workovers, and major assets could remain in the ground because the wrong development solution was chosen. On the other hand, a platform could also represent an erroneous approach if the reservoir has been overvalued. The resulting development could fail to justify the investment cost.

When a development decision is taken, knowledge of the field will be limited – including future opportunities and challenges which might arise in its producing life. Flexibility is accordingly crucial to a valuation. The danger is that the greatest weight will be given to initial investment savings, because these are the easiest to tackle or because a short-term approach is being taken. The development team will be satisfied if it can achieve a reasonable project, and the company and its present management receive positive media coverage. However, what matters in the long run for an oil company is the life-cycle economics expressed in the project's net present value – including the relevant options available. But it must be stressed in this context that realising these options could involve substantial extra costs which must be taken into account.

Oil companies have developed financial models which take account of many such options. Accuracy in applying these models depends on good communication between the various disciplines and close collaboration. Decision support models have been substantially improved, but call for suitable input parameters. According to company financial teams, they do not always get these from their petroleum technology colleagues when seeking to calculate real option values. The option models are often complex and difficult to solve, and could accordingly have limited freedom in terms of input format. Obtaining suitable input depends

on detailed knowledge of the decision support models among petroleum technologists and on their willingness to estimate suitable parameters. Ideally, the various sides should also agree on what constitutes suitable input to the decision analysis. If the input parameters are not tailored to the models, the danger is that the size of the initial investment dominates when decisions are made. Naturally, developing decision models tailored to available and relevant parameters also poses a challenge to the economists. A problem the latter face is that time will be a critical factor. The financial analysis is the final link in the chain, and the analysts have little time available. This does not seem to be the best point for the oil companies to reduce the time taken – quite the contrary, in fact.

Defending more expensive solutions on the basis of gut feeling and industrial instinct calls for considerable courage on the part of management. It is frequently the case that quantitative effects dominate qualitative ones – the former are often harder to challenge and easier to audit afterwards. An increased concentration on auditing and transparency can have the unintended consequence that excessive weight is given to easily measureable conditions when taking decisions. At certain times, too, management of the operator company – or the partners in the licence – work with a self-imposed rationing of capital, and may then opt for the cheap solution even though this yields a lower expected net present value.¹⁷

3.1 Supplementary considerations

It was demonstrated above that platform-based developments provide greater flexibility, which permits a higher recovery factor and thereby substantial additional revenues. However, a number of advantages of subsea systems have not been taken into account in the discussion and the numerical example. An important characteristic of subsea solutions is that they simplify a phased delineation and development of fields, and thereby normally provide an earlier start to production with the gathering of useful information. They usually involve pre-drilling, so that plateau production is reached more quickly. Pre-drilling can also be conducted with fixed installations, but that involves extra investment and risk. Faster development and shorter time to plateau almost always increases net present values. However, this argument assumes that a rig is available. To the extent that a tie-in is required to an existing installation, too, this opportunity must

¹⁷ See Osmundsen et al. (2006, 2007).

be available with the desired capacity at the anticipated time. Experience shows that these requirements are not always met. It was necessary to wait for spare capacity until other fields went off plateau, and tariff negotiations took time. A tie-back may also require modifications, which have often turned out to be more expensive and time-consuming than the net present value calculations assumed. But it is clear that not having to design, order and build one or more platforms with equipment and so forth helps in terms of timing. Pumps, compressors and turbines/generators have all taken several years to deliver in periods. I have been unable to obtain figures on development times for alternative concepts.

The number of well slots on a platform is determined before construction begins. Extra wells must wait for spare slots (additional slots are cheap if they are included from the start). Additional slots may therefore pose a bigger challenge on a platform than with a subsea solution where more templates can be installed. The challenge is to secure enough capacity in pipelines and control systems. Pre-investment is cheaper than wisdom after the event, but has an immediate impact on net present value calculations. Another strength of subsea solutions is that drilling locations can be dispersed to optimum points in relation to the reservoir, avoiding unnecessarily long and expensive wells.

Payment for tie-in and tariffs for subsea solutions primarily involve marginal costs on the platforms as well as a share of the fixed operating costs. Should a new platform be built, all operating costs must be borne by the discovery itself. However, this difference is only relevant for a tie-back phased in towards the end of a field's producing life – all costs must otherwise be met by the new fields. Major unexpected maintenance-related costs have arisen for fields in their final phase. As a rule, all tied-in fields must contribute to meeting these, and a subsea solution can quickly prove to have been sub-optimal in such circumstances.

4. Inadequate well maintenance

The main problem facing subsea developments is that the threshold for new infill wells and well interventions is too high. Active efforts are being made by the industry to lower this through the use of cheaper rigs, light well intervention vessels and standardised solutions.

Bente Nyland, director-general of the Norwegian Petroleum Directorate, has said that the maintenance backlog for subsea systems represents a challenge in the work of recovering the profitable reserves from existing fields on the NCS. “Many wells are out of operation,” she told Offshore.no.¹⁸ “Subsea developments present many advantages, but some challenges as well. And the industry must put better maintenance systems in place.”

So why have subsea wells not been maintained? Reserves frequently represent a conservative figure, and such estimates may often indicate in a given year that too little oil remains to justify a well intervention in the light of high rig rates. If this condition remains fairly constant for a few years, the realisation with hindsight is often that one should have intervened earlier and made more money but that it is now definitely too late. Nor were rig availability and total drilling costs given enough emphasis to ensure optimum earnings. The combination of small reserves and an uncertain upside for remaining resources in a field led – and continues to lead – to well intervention on subsea installations being neglected.

Plans to build light intervention rigs existed as early as the late 1980s, but foundered through lack of collaboration in the industry, new business models in the oil companies and uncertain crude prices in the early 1990s. The fields were in full plateau production and nobody wanted to make themselves unpopular by proposing that lots of money be spent on something which was a problem for the future. The concentration on short-term production indicators could have played a part here. Well tools were developed around 1990 when the subsea licences joined forces to create a pool of installation and maintenance equipment. The same should have been done for light well intervention vessels. As illustrated in figure 2, developments have shown that this was an erroneous decision. The well maintenance backlog is now substantial and has led to production losses which cannot be retrieved (confer the downgrading of reserves on the Halten Bank).

5. Case – Gullfaks South

¹⁸ Offshore.no, 14 January 2011; http://www.offshore.no/sak/Subsea-br%C3%B8nner_st%C3%A5r_uvirkosomme

Gullfaks South lies due south of Gullfaks in the northern North Sea. It has been developed with 12 subsea templates tied back to the Gullfaks A and C platforms.

5.1 Description of the field

Discovery year: 1978

Development approved: 29 March 1996

On stream 10 October: 1998

Operator: Statoil Petroleum AS

Present licensees: Petoro AS 30.00%, Statoil Petroleum AS 70.00%

Gullfaks South has been developed in two phases. The plan for development and operation (PDO) of phase I embraced the production of oil and condensate from the 34/10-2 Gullfaks South, 34/10-17 Rimfaks and 34/10-37 Gullveig deposits. Approved on 8 June 1998, the PDO of phase II embraced the Brent group in Gullfaks South. The 34/10-47 Gulltopp discovery was incorporated in Gullfaks South during 2004. Gulltopp was produced through an extended-reach well drilled from Gullfaks A. The PDO for Rimfaks IOR and the 33/12-8 A Skinfaks discovery was approved on 11 February 2005, and embraced a new template and a satellite well. Incorporated in Gullfaks South, Skinfaks came on stream in January 2007.

The Gullfaks South reservoirs lie in Brent group sandstones from the middle Jurassic, and in the Cook, Statfjord and Lunde formations of early Jurassic and late Triassic age. Production occurs from the Brent group and Statfjord formation. These reservoirs lie 2 400-3 400 metres deep in rotated fault blocks. Gullfaks South's reservoirs are extensively segmented by many faults, and the Statfjord formation has poor flow properties. The other formations have fairly good reservoir quality.

Production from Gullfaks South is now being pursued by pressure reduction after gas injection ceased in 2009. On Rimfaks, the Brent group is producing with full pressure maintenance by gas injection, while the Statfjord formation has partial pressure support by the same means. The Gullveig and Gulltopp deposits are being produced by pressure reduction and natural water drive, and their output will be influenced by Gullfaks production. Oil is piped to Gullfaks A for processing, storage and export by shuttle tanker, while the rich gas is

processed on Gullfaks C and exported via Statpipe to Kårstø for further processing and dry-gas export to continental Europe.

Data source: *Facts about the Norwegian Petroleum Sector*, 2010.

5.2 Controversial development solution

Gullfaks South is an example of a controversial choice between a platform and a subsea installation. The project was regarded as marginal, and earlier developments on Gullfaks – all platform-based – had involved high capital spending (with substantial overruns) and are viewed with hindsight as having low profitability. Gullfaks South lies in relatively shallow water, and the reservoir was known to be complex. An optimistic plan was drawn up with a minimum of wells. Rumour has it that discussions on the choice of solution indicated that a platform could be defended if recovery were increased by four-five per cent. Disagreement prevailed in the licence over the development solution, but the majority was convinced that it would be possible to achieve a recovery factor similar to the other Gullfaks fields even with a subsea installation, despite the complex reservoir. Gullfaks South's wells were drilled by a semi-submersible. Progress was poor and costs doubled. While platform-based developments also experience cost overruns, as on Gullfaks, these are of a much lower order of magnitude (in percentage terms, well to note). A number of problems have been experienced during the production phase which could have been resolved better with a platform solution. According to unofficial estimates, 20-25 per cent of the reserves will be recovered compared with 60-70 per cent for the other Gullfaks fields. The loss of reserves is substantial and, even allowing for possibly greater reservoir complexity, industry observers maintain that Gullfaks South could probably have attained a recovery factor of about 40 per cent with a fixed installation and a drilling rig constantly available.

The lessons have hopefully been learnt from this experience. We see that many NCS developments have opted for a platform, including Ringhorne, Kvitebjørn, Gudrun and Valemon. Relatively high oil prices at the decision point may have been a factor here.

6. Conclusion

Developers have eventually become better at and more conscious about implementing real options in their decision support systems when choosing development concepts for petroleum fields. But are they taking account of all relevant options? In practice, the position is probably that the large number of complex and mutually dependent real options available in such circumstances do not fit completely with existing decision models. Model calculations must accordingly be supplemented by judgements. It is important that petroleum technology expertise is incorporated in such decisions. This case perhaps also represents an example of the way decision-takers can be strongly influenced in certain circumstances by “the latest experience”, and that their perspective can thereby become sub-optimal. At certain times, the perspective at the decision point seems primarily to be the lowest possible initial investment. It is accordingly important that the companies work systematically on learning and experience transfer in a decision-making context.

Another relevant question is whether the basic estimates utilised as input to the decision models are the best. Experience from the NCS and the UK continental shelf shows that the number of wells required in a field development are often underestimated – by 30 per cent, according to an unofficial estimate. This points towards a platform-based solution, where drilling is much cheaper once the initial investment has been made. If real options and the best cost estimates are not taken adequately into account in the decision analysis, a substantial IOR potential could have been lost as early as the choice of development solution. A subsea facility is often a relevant option in really deep water.¹⁹ It is also a good choice for small fields and reservoirs with a low level of complexity. The technological progress made in cooperation with the major suppliers, a number of whom have their main base in Norway, has been useful and necessary, and has represented an impressive export success. Continuous advances in subsea technology have also gone some way in reducing the disadvantages of such developments. When choosing a concept, account must also be taken of the fact that topside technology develops and that new production solutions devised after the development date will often be easier to adopt if a platform has been chosen. Pilot projects are essential for assessing alternative IOR methods, both present and future. These are easier to pursue from a fixed installation. So platform-based developments are favourable for continued innovation on the NCS.

¹⁹ Some exceptions exist here. A floating installation is being considered for the Luva field in 1 270 metres of water, for instance.

The analysis has illustrated that the choice of concepts is complex, with inputs from many parties and technical disciplines. Establishing good communication is crucial here. When choosing a concept, it is often impossible to establish which solution is unambiguously and objectively the best since so many sources of uncertainty exist. In such circumstances, decisions are influenced not only by knowledge but also by power. The relative strengths of the various technical disciplines (reservoir/drilling/facilities/project execution) will mean a great deal in practice. This is difficult to handle in all organisations. Much can be achieved through the requirements and internal control bodies established by the company for work processes and the way assignments should be handled.

In addition, it is important that some kind of balance of power exists between these disciplines. The limited power and influence of people with sub-surface expertise represents a problem in this context. There are several reasons for this. In numerical terms, the petroleum technology disciplines (including geologists, geophysicists, reservoir engineers and production engineers) form a relatively small group. Furthermore, a culture of seeking senior executive positions no longer seems to exist within Norway's petroleum technology disciplines, as it does among economists and in part of the facilities discipline. Efforts should be made to correct this imbalance, partly by adjusting the composition of company managements and partly by taking more care to include arguments from petroleum technologists in decision processes.

When the sub-surface community comes up with a new idea, it is met with a well-nourished structure of control which consists not of hunters but of controllers and critics. These functions are also important, but a balance must exist. Furthermore, the facilities discipline can have its own agendas which do not always coincide with high reservoir utilisation. Sub-surface expertise accordingly needs support and backing in the executive management. This should be perceived as natural, since the biggest challenges to the oil companies for the moment are on the resource side, related to production curves and reserve replacement. It is accordingly appropriate that sub-surface expertise strengthens its position in the top management of the companies – through the creation of a post of resource vice president, for instance. The top management and board should have a cross-disciplinary composition, and a number of considerations indicate that sub-surface expertise is not adequately represented.

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