NORWEGIAN PETROLEUM DIRECTORATE

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Project execution on the Norwegian continental shelf

English translation of the report *Prosjektgjennomføring på norsk sokkel*

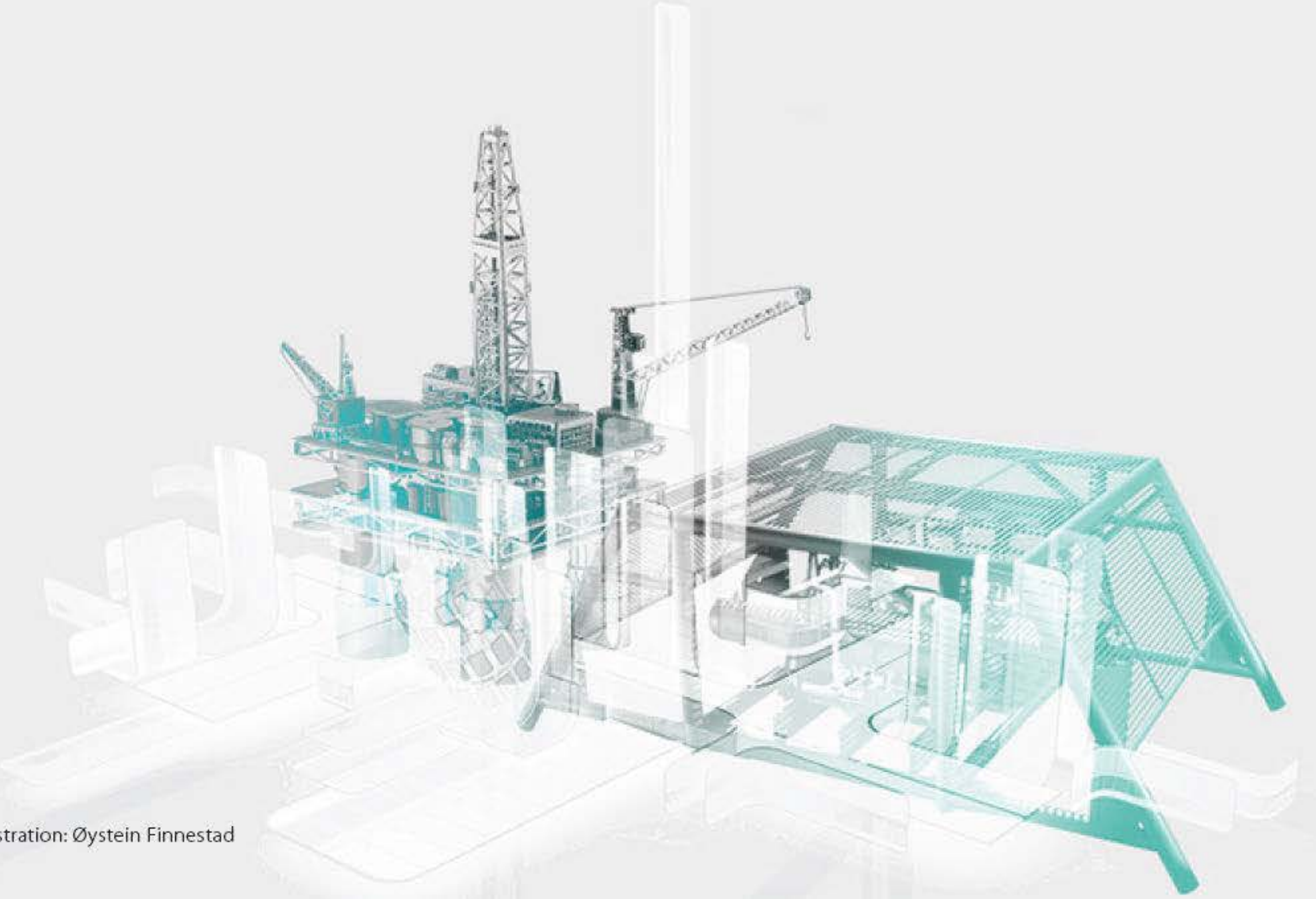

Illustration: Øystein Finnestad

Contents

1 Introduction

This report evaluates development projects approved on the Norwegian continental shelf (NCS) in 2007-18 and the experience gained by the industry related to their execution. It provides an assessment of how far the licensees have succeeded in implementing projects to the planned schedule and cost estimate. An important purpose of the report is to share this type of information and the experience acquired by the Norwegian Petroleum Directorate (NPD) through its regular follow-up of the projects. Finally, the report looks at the types of developments which can be expected on the NCS over the next few years and some of the associated challenges. It is important that the licensees on the NCS make active use of the findings in this report and other relevant experience in their project development work.

The NPD published its report on *Vurdering av gjennomførte prosjekter in 2013*, covering experience with and lessons learnt from five developments. On the basis of this review, a number of key factors were identified which are considered important to take into account when executing any new project. In the wake of this report, the authorities have strengthened their follow-up of developments in an early phase to ensure that important factors are in place. However, responsibility for planning and executing projects rests with the licensees within the framework specified by the authorities.

A successful project is one completed on schedule and within budget, and without incidents related to health, safety or the environment (HSE). The field concerned must also meet expected production rates. It has been necessary during work on the report to limit its scope. The Petroleum Safety Authority Norway (PSA), which is responsible for HSE in the oil and gas sector, recently published a report which studied three development projects /5/. In this report, the NPD has emphasised costs, schedules and reserve developments as well as operator experience. In order to describe progress with costs, the review has been based on projects with an approved plan for development and operation (PDO) or plan for installation and operation (PIO) in 2007-18. The Ministry of Petroleum and Energy (MPE) reports the status of progress in development projects to the Storting (parliament) annually in Proposition 1S. As a result, the cost figures used in this report are already in the public domain. Particular attention is devoted in the report to projects developed with platforms or subsea installations, since these account for the majority of the cases considered. Final costs, start-up date and reserve developments are compared with plans and estimates in the PDO documentation.

2 Summary

The NPD has reviewed 66 developments pursued on the NCS between 2007 and 2018. This review shows that most of the projects end up with costs which fall within the estimates given in the PDO. Relatively few projects experience cost overruns, and this number has decreased further in recent years. An important reason for this is that the licensees have done sufficiently detailed early-phase work before sanctioning the project. Market trends following the oil price slump have also made a positive contribution, since the availability of resources and capacity at the suppliers has been better than in the years before the downturn.

Just over 80 per cent of the selected projects have been delivered within or below the uncertainty range in the estimate. Subsea developments very often progress as planned, and 90 per cent of them were completed in line with or below the PDO estimate. Experience shows that platform-based developments are more challenging, and several of these have cost overruns. Nevertheless, the review reveals that 71 per cent of these projects were delivered or are being developed in line with the estimated cost.

On average, projects were completed about 3.5 months later than planned. The average delay is longer for platform developments than for subsea projects.

The report compares projects approved in 2007-12 with those given the green light in 2013-18. This review shows that project execution improved in the second period compared with the first. More of the projects in 2013-18 have been developed in accordance with the time and cost estimates.

While a majority of the large and medium-sized fields on the NCS have seen their reserves increase, a majority of the small fields have witnessed a reduction. This tendency also applies to the projects covered by this report.

The NPD has regularly followed up projects in the execution phase for a number of years. Dialogue with the operator and licensees builds up the NPD's knowledge about and experience of project execution on the NCS. On the basis of this follow-up, the report highlights the following factors which are important when planning and executing new projects.

- The operator must establish a project organisation with sufficient expertise and capacity to plan and execute the project.
- Detailed planning, with a good process for concept selection and enough time to mature the selected concept before the PDO, is crucial for the project to get off to a good start and achieve execution success. In this context, a quality assurance system is important for ensuring sufficient technical detailing and maturation at the various project milestones.
- The project organisation should actively seek to learn lessons and transfer experience from execution and operation of other developments, and take account of these in its planning.
- A contract and execution strategy must be established which is tailored to the expertise and capacity of the operator and the supplier. Continuity of main contractor(s) from front-end to detail engineering could be positive for execution, since it helps ensure that contractors are familiar with the project when detail design begins and that they have ownership of the solutions chosen.
- The operator must manage the project on the basis of risk assessments, cost developments and progress, and adjust project follow-up as well as taking action should problem areas be identified.

In addition to the operator, the other licensees have a responsibility for project execution. They must therefore contribute their expertise to the planning and execution of projects. In 2016 (with minor adjustments in 2018), the guidance for PDOs and PIOs was updated in part to make this responsibility clearer. More information is now required about project execution, including documentation of measures taken by licensees to fulfil their “see-to-it” duty.

The licensees have highlighted the topsides as particularly challenging in platform developments. Errors and deficiencies in engineering and constructing these structures are an important cause of delays and cost overruns. The topsides have incurred large cost increases even in several of the projects which have ended up overall with costs in line with the PDO estimate. In the NPD's assessment, expertise and experience in the operator's project organisation will be more significant for the outcome in this type of project than with subsea developments. Companies with a portfolio of such projects on the NCS and with a project organisation which builds experience and expertise over time have better results than operators with few projects. Outcomes are more varied for the latter group.

Many large developments were pursued in the years before the oil price slump. Capacity constraints in Norway contributed to the award of several contracts to Asian yards. The review reveals no clear link between successful project execution and the geographical location of the construction site. Several of the operators have nevertheless pointed to factors which experience shows to have made building in Asia more demanding than in Norway with more familiar partners. It is important to have sufficient expertise about and understanding of the cultural and organisational conditions at the yards. The latter also lack expertise in complying with Norsok standards, and specialist teams with Norsok expertise and experience from similar developments were therefore established in several of the projects to compensate for this. More follow-up and a greater presence than expected have also been required at the yard's subcontractors. The effect of these conditions has often been insufficiently assessed when estimating costs and awarding contracts, and has in many cases been an important contributor to cost increases in this part of the project – even in developments which lie overall within the uncertainty range.

On average, projects on the NCS experience fewer delays and meet their cost estimates better than developments on the UK continental shelf (UKCS). Both continental shelves have seen an improvement in project execution during recent years.

The average size of current discoveries on the NCS is smaller than before. A majority are most likely to be developed with subsea facilities. Experience presented in this report shows that such projects are almost always executed in accordance with the approved plans, regardless of the operator's project development experience. However, reviewing developments after fields come on stream shows that reserves often decline for smaller projects compared with expectations in the PDO. Drilling many appraisal wells before a PDO is often not considered beneficial on small fields, and the decision base may then be relatively more uncertain than for larger discoveries. This indicates that achieving a good understanding and best estimate of the reserve base and choosing a development concept which can handle the uncertainties if the downside materialises are at least as important as executing a project on time and to budget.

Where fields on stream are concerned, good facility knowledge and maintenance planning are important in preparing a realistic decision basis for modification projects. Experience from some of these fields shows that changes have occurred because drawings were insufficiently updated, and it proved necessary to replace or upgrade more equipment than expected.

3 Developments on the NCS

This chapter addresses changes related to the industry, the market and regulation by the authorities since 2013.

3.1 Summary of the report on projects executed on the NCS

Vurdering av gjennomførte prosjekter på norsk sokkel /1/ (Assessment of projects executed on the NCS) was drawn up by the NPD for the MPE in 2013. This looked at five projects – Skarv, Yme, Valhall Redevelopment, Tyrihans and Gjøa. Its main purpose was to understand the reasons why the licensees either succeeded or failed to execute the project on time, to the specified quality and to budget in relation to the officially approved PDO/PIO.

The report concluded that most projects end up with development costs within the uncertainty range specified in the PDO. Despite this, the projects recorded big cost increases overall – largely as a result of a few cases with substantial overruns.

The review found that some important conditions must be in place for projects to succeed.

Early-phase work
A number of the projects in the review were managed on the basis of excessively ambitious plans, and the time allocated for planning work became too short. Front-end engineering design (Feed) had not been completed before the investment decision for several projects was taken. The basis for initiating construction and procurement was thereby inadequate, and major design changes were required in a number of the projects during the building phase.

Prequalification of suppliers
Following up all deliveries along the way will be very demanding in large offshore projects. The operator must therefore prioritise which areas it will supervise directly. Detailed prequalification of suppliers on the basis of earlier experience could reduce the risk of problems during execution and thereby the need for follow-up. The review showed that the operator relied far too much in a number of cases on the contractor being able to deliver on the specified requirements.

Contract strategy
The project's contract strategy must ensure cost-effective progress and quality, and give the operator opportunities for follow-up, control and corrective measures along the way. It should reflect the key risk elements in the project and be viewed in relation to the operator's direct follow-up and prequalification of suppliers. The review showed that the operator should consider taking greater direct contract responsibility for key equipment-package deliveries.

Operator's follow-up
All parts of the project require good and qualified follow-up, and ensuring this is the operator's responsibility. Follow-up must be tailored to the suppliers and contract model chosen. Understanding of the Norsok standards and Norwegian requirements are a bigger challenge at foreign yards than for domestic construction contractors, and the operator has a special responsibility to follow that up. This was summed up as a lesson learnt in several of the projects reviewed.

A high level of activity meant higher prices for input factors and a shortage of resources. Where projects had encountered difficulties, a high level of activity led to more restrictive conditions for execution and was viewed by the NPD as a contributory factor to the big time and cost overruns which occurred in some of the projects reviewed.

3.2 Changes to the licensees' project development process

Many operators on NCS in recent years have made concept selection earlier than before. While this used to be done immediately before or at the same time as the decision to continue (BOV), several examples have been seen more recently of the choice being made about half a year before this point.

Project development

Licensees pursuing projects on the NCS utilise varying development processes. A common feature is that they have several decision gates (DGs) over the life of the project, with defined requirements for the level of engineering and estimating to ensure the right quality at the various DGs. A schematic presentation of the project execution model as defined by the authorities in the PDO/PIO guidelines is presented in figure 1.

Oil and gas projects are split primarily between planning and execution phases. During the former, various concepts are evaluated in order to identify the best development concept, and the one selected is further matured towards an investment decision. A PDO of a petroleum deposit or PIO of facilities for transport and utilisation of petroleum is submitted. In the execution phase, detail engineering is completed and the selected concepts/facilities are built, installed and brought into operation.

The authorities define DGs for a project planning phase in their PDO-PIO guidelines.

- Concretisation decision – BOK: *milestone where the licensees have identified at least one technical and financially feasible concept which provides a basis for initiating studies that lead to concept selection.*
- Decision to continue – BOV: *milestone where the licensees decide to continue studies for one concept which leads to a decision to implement.*
- Decision to implement – BOG: *milestone where the licensees make an investment decision which results in the submission of a PDO or PIO.*

Choice of concept is an important DG in a project's planning phase. A shift then occurs from studying many options to focusing on a single concept which will be matured up to an investment decision.

The guidelines also describe expectations for cooperation between the licensees and the authorities and the documentation to be submitted to the authorities during the planning phase. Among other requirements, the licensees must inform the authorities at the BOK, the BOV, and possibly the choice of concept if this occurs earlier than the BOV. The aim is to lay the basis for efficient official consideration of the final plans.

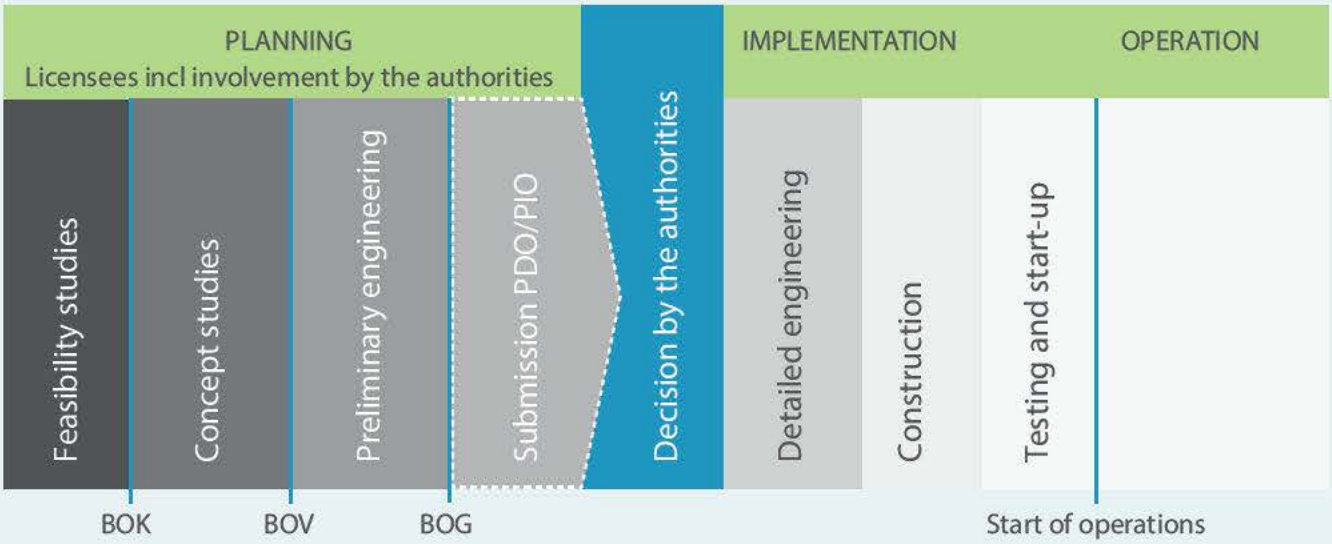

Figure 1 The project development process

The NPD's 2013 report concluded that several of the projects suffered significant deficiencies in their planning phase. Allocating time to maturing the concept before the BOV could make a positive contribution to project execution.

At the same time, conceptual choices made early could involve greater uncert ainty. Estimates for recoverable resources, costs and profitability become gradually more certain from the decision to concretise (BOK) to the BOV. Early selection can thereby increase the probability that later changes will be needed. This applies particularly to decisions taken before the BOK, where the risk could exist that good solutions are rejected too early. The authorities want the concept with the highest socio-economic value to be chosen, and for this to be adequately documented by the operator.

3.3 Strengthened follow-up of projects in the planning phase

Norway's framework for petroleum operations provides a clear division of roles and responsibilities between the authorities and the industry. The authorities regulate the sector by defining parameters which the companies operate within. Players in the industry have the greatest knowledge, expertise and information about opportunities and challenges in their business, and therefore conduct exploration, development and production activities. Full responsibility for operations, including project planning and execution, rests with the companies.

Given that certain projects have experienced big cost overruns and delays, the NPD has increased its expertise since 2013 on the subject of project execution and strengthened its follow-up of projects in the planning phase.

A dialogue will normally be conducted during the planning phase between the licensees and various government bodies. This is important in order to address the various development options and challenges during the planning process, including facilitating efficient final consideration of the plans.

Since 2013, the NPD's feedback to licensees at BOK and BOV has become more formalised. It will normally cover expectations which the authorities regard as important for their ability to approve the final plan, and which the licensees should therefore take into account in further work towards project sanctioning. In this phase, the NPD will also request assessments of key aspects associated with project maturation and execution. The experienced gained by the NPD is applied in its dialogue with the operators in order to achieve improvements.

The PDO/PIO guidelines were updated in 2017 as a consequence of large cost overruns in certain projects, and some further changes were made in 2018 on the basis of comments from KonKraft. Section 5.6 on organisation and implementation now requests more information on project execution than before, along with details of partner involvement and quality assurance. The PDO must contain a description of the project's management system, the contract strategy for the development, and the overall method for bid evaluation and supplier choice. It also has to describe experience transfer from recently executed and comparable projects, involvement of the partners in planning and execution, and the experience of the operator and the project organisation from comparable developments. Furthermore, a description must be provided of the licensees' risk assessments, including risk management and follow-up of the project.

When the PDO has been submitted, the NPD assesses the licensees' development plans, including estimates and execution strategy. The NPD's PDO evaluation provides a basis for the MPE's assessment and for further consideration by the government or the Storting (parliament).

In recent years, the NPD has also had more regular meetings with operators of selected projects to address such matters as project progress, cost developments, challenges and experience. This work gives the authorities knowledge of and experience from projects, providing the basis for looking at conditions in the planning phase which are important for project execution.

The Norwegian administrative model
Petroleum resources on the NCS belong to the Norwegian state, and the main objective of petroleum policy is to make provision for profitable production of the oil and gas resources in a long-term perspective. That goal is enshrined in the Petroleum Act, which has been adopted by the Storting to define the framework for administering the industry.

The Norwegian framework for petroleum operations involves a clear division of roles and responsibilities between the authorities and the industry. This distinguishes between regulation and commercial activity. The authorities do not develop the petroleum resources themselves, but contribute to value creation by making provision for their commercial exploitation. They regulate the sector by establishing and maintaining a framework in the form of statutes, statutory regulations and licences. That gives licensees on the NCS both rights and duties.

The licensees create value within these parameters. They are the industry players with the greatest knowledge of, expertise about and information on opportunities and challenges in their business. They are therefore in charge of exploration, development, operation and cessation. The companies bear the full responsibility for these day-to-day activities, which includes ensuring that they are conducted in accordance with the parameters set by the authorities.

All the licensees in a production licence are responsible for project execution. While the operator has a particular responsibility for the actual implementation, the other licensees have a see-to-it duty to ensure that it fulfils its responsibilities.

3.4 Clarifying the see-to-it duty in planning and executing projects

Day-to-day management of operations is conducted by the operator on behalf of all the licensees. It therefore has a special duty to ensure that activities are conducted in a prudent manner and in accordance with the regulations in force at any given time. The licensees have a duty to see to it that the operator fulfils its obligations, including planning and execution of projects.

In connection with amending the PDO/PIO guidelines, the authorities have emphasised the see-to-it duty of the licensees related to planning and executing projects and now require more explicitly than before that licensees document their plans:

> The operator has practical responsibility for preparation of PDOs and PIOs. This work must take place in close cooperation with the other licensees. The licensee group shall function as an internal control system in the production licence. The purpose is to ensure a high-quality decision basis, and a strategy for efficient quality assurance should be prepared as early as possible in the planning of a PDO and PIO, where involvement of the licensees and transfer of experience from other projects is safeguarded.

This means that the see-to-it duty represents a key part of quality assurance for developments on the NCS. Pursuant to the guidelines, all licensees other than the operator must account in writing for the activities they have conducted/are planning in order to fulfil this duty in relation to the preparation and implementation of the PDO.

3.5 Market developments

The petroleum industry is raw-material-based and, like most such sectors, its level of activity is governed by the raw material price. This has a direct impact on the projects. It is often the case that high oil prices lead to many developments being sanctioned, with consequent resource and capacity constraints at the suppliers. This can make it demanding to implement a project as planned and budgeted. Low oil prices make it more demanding to get projects sanctioned. Resources and capacity become more available, but tougher competition and lower earnings put pressure on suppliers. The unpredictability of oil prices is a challenge in itself for such capital-intensive projects.

Since Norway's oil activity started more than 50 years ago, the industry has experienced many price-related upturns and downturns. Oil prices fell to low levels in 1986, 1998, 2001 and 2008, leading to changes and restructuring. High and stable oil prices in 2010-14 boosted activity but eventually also the level of costs. The breakeven price for new developments moved in some cases towards USD 80 per barrel. Oil prices fell markedly in 2014, from a peak of more than USD 100/barrel to less than USD 30/barrel at bottom. This had big consequences for many companies in the industry, and has resulted in major changes. Although oil prices today have improved from the lowest level, licensees continue to focus on the need for new projects to remain profitable when prices are low.

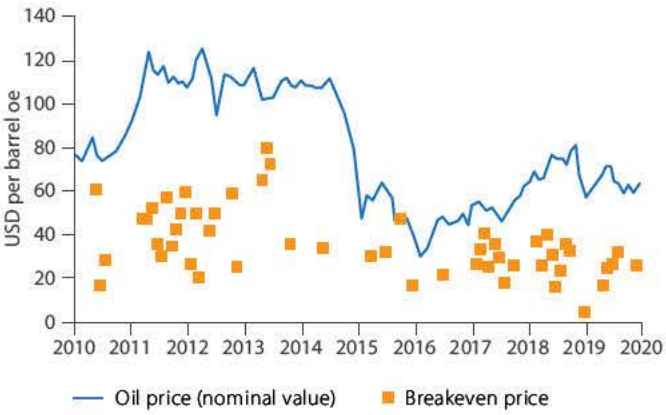

Figure 2 Oil price developments and breakeven prices for projects on the NCS.

The 2014 oil price slump meant that the oil companies devoted increased attention to costs and cost efficiency. Many planned projects – both large developments and modifications – were therefore halted or postponed. As current projects were completed and the level of activity declined, substantial downsizing took place at all levels of the industry. Hardest-hit were the supplier and service sectors. That has led to restructurings. Companies were taken over or merged, and some went out of business.

One factor which helped to moderate the downturn after 2014 is the Johan Sverdrup discovery in 2010. This meant that the level of activity on the NCS since 2014 has been higher in relative terms than might normally have been expected. Many of the contracts have been awarded to Norwegian suppliers and thereby helped to maintain the level of activity at a time of low oil prices.

A number of measures have been implemented by the industry in recent years to improve efficiency and reduce the level of costs. These steps have yielded results in the form of reduced costs for investment in new projects, production wells on producing fields, and operation and exploration. Oil prices rose to about USD 60/barrel in 2019. Earnings in today's market are good – in some cases, as good as or better than in 2014. However, the supplier and service industry reports that its earnings are still under pressure, and that it must improve this in order to continue delivering good services.

The NPD has noted that many development projects over the past year have faced risks related to shortages of labour and capacity in certain areas. Such a development could lead to cost increases and capacity constraints which might have a negative effect on project execution.

3.6 Changes to forms of contract and collaboration

The contract strategy says something about how suppliers and competitive prices will be secured for the project, and how it will be managed and followed up in the execution phase. This strategy must take account of many elements, including project size and complexity, operator and supplier expertise and experience, and capacity in the market.

The operators can choose to divide up a project and award contracts in various ways. Their degree of follow-up work could vary according to contract types and who is awarding them. Putting together various parts of a project in a single (turnkey) contract means that a main contractor deals with the interfaces between the different deliveries. One of the NPD's recommendations after its 2013 project review was that the operators should consider accepting greater direct contract responsibility in connection with the delivery of key equipment packages.

Turnkey assignments have been the most widely used form of contract for building platforms on the NCS. On the basis of its experience with the most recent big projects, Equinor has opted for a mix of approaches – both turnkey contracts and a split into engineering/procurement and construction assignments have been used.

Several of the oil companies, such as Aker BP and Centrica (now Spirit) have emphasised long-term contracts (alliances) with a few selected suppliers rather than competitive tendering for each project.

Collaborating with the same suppliers over a longer period could be advantageous. This achieves continuity from planning to execution and thereby avoids the risk associated with changing supplier along the way. At the same time, such long-term agreements can have the disadvantage of limiting competition between suppliers and reducing the number of technological solutions assessed. The licensees in the production licence determine the contract strategy, and thereby also decide if the operator's alliance agreement with the suppliers is appropriate for the relevant project.

Alliance

An alliance is a collaboration model between oil company and supplier, and often also between suppliers where several are in alliance with the oil company. Through this approach, the oil company seeks to engage the suppliers at an early planning stage and create incentives (common goals and financial interests) which motivate the identification of good solutions. The suppliers generally follow the project through all its phases, from planning to construction. Aker BP has also chosen a model where the project organisation can be staffed with personnel from both operator and suppliers. According to the company, this can contribute to more efficient work processes which help in turn to shorten planning and execution times and reduce costs. Operators who have entered into alliances usually base these on a frame agreement.

Frame agreement

In this context, a frame agreement is a contract entered into between an oil company and a supplier. It specifies key contractual terms (price, what is to be delivered and so forth) for later call-off to the contract. Frame agreements are generally entered into with several suppliers within a segment, which opens for competition when call-offs are made.

Turnkey contract

This term involves assembling various parts of a project into a single assignment where the main contractor is responsible for the interfaces between the various deliveries. Such a contract typically covers engineering, procurement and construction (EPC), but can also include transport from yards to Norway and possibly installation (EPCI) on the field. Commissioning (c) may also be covered.

The table below explains some of the concepts utilised in connection with contracts on the NCS and later in this report.

	English	Norwegian
Feed	Front end engineering design	Forprosjektering
E	Engineering	Prosjektering
P	Procurement	Innkjøp
C	Construction	Konstruksjon
F	Fabrication	Fabrikasjon
Ma	Management assist	Prosjektassistanse
I	Installation	Installasjon
H	Hook up	Sammenstilling
C	Commissioning	Uttesting

Table 1 Main activities normally included in contracts for offshore projects.

4 Project execution on the NCS

This chapter summarises experience acquired from completed and ongoing projects on the NCS, with particular attention paid to the post-2013 period.

Cost data for the projects have been taken from Proposition (Bill) 1 S to the Storting, which is drawn up annually by the MPE as part of the input to the national budget. This presents the project's PDO estimate, the latest updated cost estimate, and cost trends since the PDO and over the previous year. The figure presented is the project's total costs, which include possible gain/loss on changes to the exchange rates assumed in the PDO. Costs estimates in this report have been inflation-adjusted to 2019 value in line with the consumer price index. Operators report to the MPE up to the start of production. Work may still be outstanding in a project after the field has come on stream – related to drilling wells, for example. The figures in the national budget are therefore the latest cost estimate, which could vary from the final development cost.

Planning data are taken from the PDO and the NPD's fact pages. The actual start date is compared with the planned time stated in the PDO. The latter is often specified as a month rather than a day. In those cases where no specific date is stated, the base data is attributed to the last day of the month.

Developments in field reserves are taken from the NPD's resource accounts, based on reporting to the revised national budget for 2019 (reported in the autumn of 2018).

4.1 Overview of sanctioned development projects

PDOs for 36 projects were approved in 2007-13. The corresponding figure for 2013-18 was 30. Figure 3 presents an overview of the types of development concepts chosen for these projects. Most were subsea developments, followed by fixed and floating facilities.

The distribution of development concepts is comparable for the two periods. Total estimated costs came to just over NOK 470 billion for both, and break down more or less equally between the various development concepts. See figures 4 and 5. Fixed facilities account for roughly 45 per cent of the estimates, with subsea developments and floating facilities representing about a quarter each. [1]

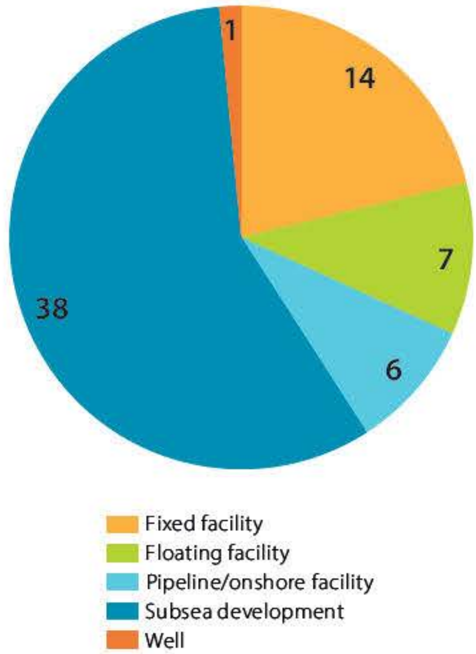

Figure 3 Projects by development concept. A total of 66 projects had an approved PDO/PIO in 2007-18.

Big variations may exist within each category in the functionality, complexity and cost of development concepts. Fixed facilities, for example, include phase 1 of Johan Sverdrup, with four such facilities and a PDO estimate of almost NOK 130 billion, as well as Oseberg west flank 2, an unmanned wellhead platform estimated at about NOK 8.5 billion in the PDO. The floaters cover various hull types – Aasta Hansteen is a Spar, Goliat has a circular floating production, storage and offloading (FPSO) unit, Knarr and Johan Castberg have ship-shaped FPSOs and Gjøa is a semi-submersible. Most of the projects are newbuilds, but

[1] Most projects incorporate subsea installations and wells in their development concept. In this report, the fixed and floating facility category covers fields developed with such installations (but which may also feature subsea wells/equipment). The subsea development category covers fields where the seabed facilities are tied back to existing infrastructure, and the well category encompasses a project limited to wells. The costs specified in this report are the total figure for a project, and are not broken down by discipline.

some are also large modifications. Njord Future involves upgrading the existing Njord A and B facilities. Yme New Development is based on reusing equipment left from the earlier project on this field, along with readying the *Maersk Inspirer* drilling rig for production.

The *subsea development* category also embraces big variations in concepts and complexity, with the number and type of wells and pipelines as well as the distance from and scope of work on the host facility differing between the projects. Investment estimates vary from about NOK 1.5 billion for Skogul and Hyme to just under NOK 20 billion for Snorre Subsea Expansion (SEP).

Fifty-three of the projects had come on stream in 2019, with 12 still under development. One – Yme, with its PDO approved in 2007 – was terminated without completing the project. A new Yme development was approved in 2018. This is still in progress and forms part of the base data.

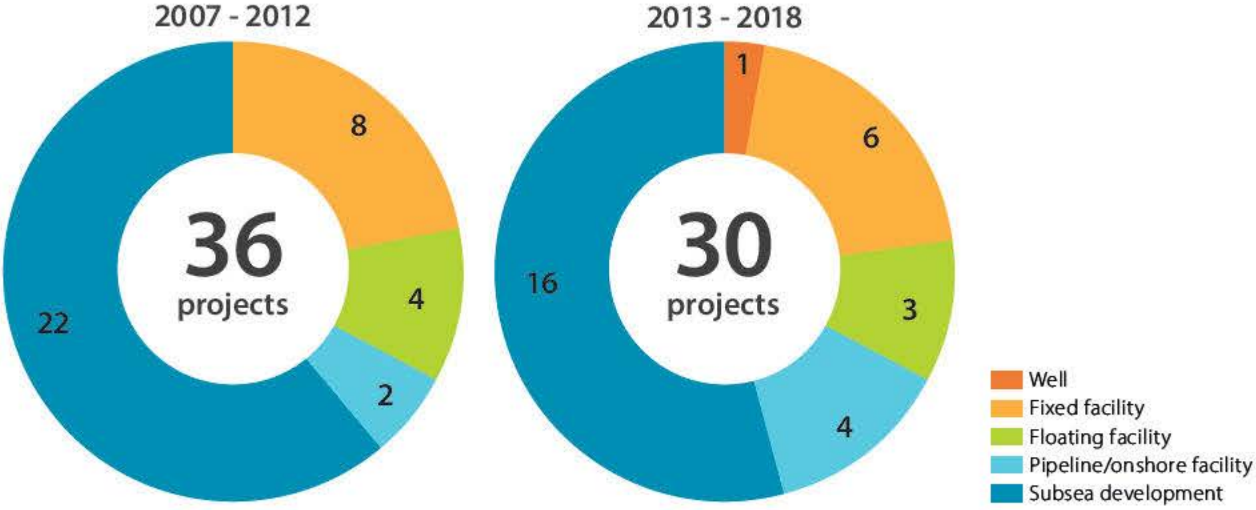

Figure 4 Projects by development concept and period. Thirty-six projects were sanctioned in 2007-12 and 30 in 2013-18.

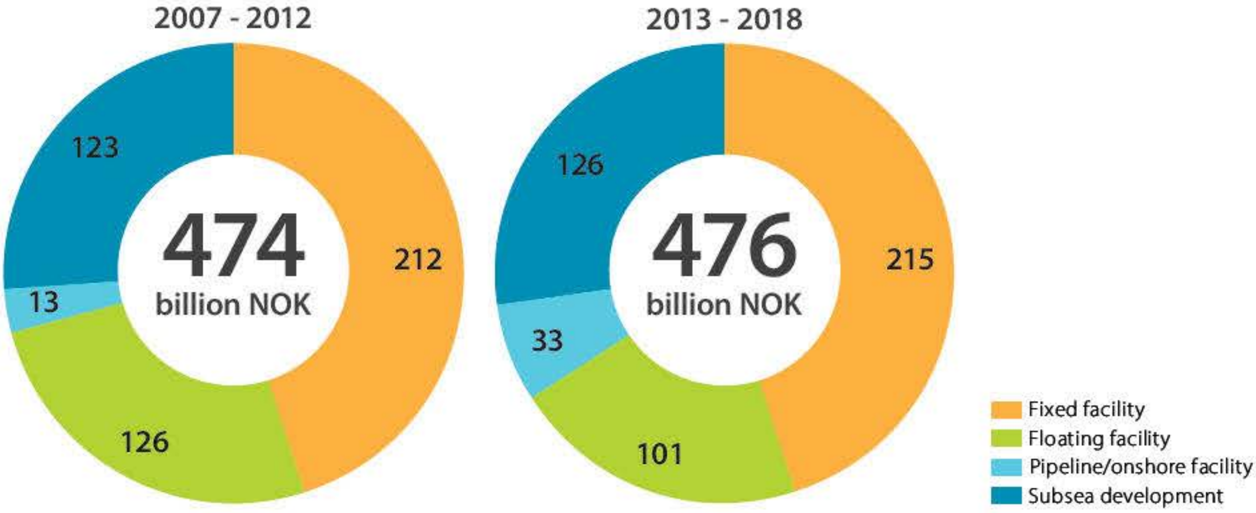

Figure 5 Distribution of PDO cost estimates by development concept and period. Planned investment for projects in 2007-12 totalled NOK 474 billion in 2019 value. The overall cost estimate for 2013-18 was NOK 476 billion in 2019 value.

An overview of projects covered in this report and their operator is provided at the end of the report. Equinor accounted for about half of the developments and of all planned investments. The remaining half breaks down between 16 operators who were responsible for one-three projects each.

4.2 Cost developments

All costs underpinning the decision taken at the PDO/PAD stage are estimates. These will take account of uncertainties in the project, and therefore lie within an interval expressing a certain degree of confidence. More detailed engineering is required to firm up the estimates. How firm the latter must be before a project is sanctioned will always be a matter of judgement.

Licensees on the NCS normally require that estimated costs have a maximum uncertainty of +/- 20 per cent within an 80 per cent confidence interval at the PDO. This means that, if a given project is repeated many times, estimated costs would be within the +/- 20 per cent uncertainty range in eight out of 10 cases. A project where costs increase or decrease by less than 20 per cent of the PDO estimate is thereby considered to have been implemented to budget.

At the PDO stage, the licensees prepare a master control estimate (MCE). Their project organisation monitors cost developments (and the plan) throughout the execution phase. Updated cost estimates and plans – known as the current control estimate (CCE) – are prepared regularly for the projects, and the latest of these is used as the basis for reporting to Proposition 1 S. Monthly project reports sum up progress and cost developments compared with the latest CCE update and the MCE.

Projects which came on stream in the autumn of 2019 (Johan Sverdrup phase 1, Utgard, Valhall flank west) are included in this report, but will secure a new and more updated cost estimate in the 2021 national budget. The base data also include a number of projects not yet on stream. Their costs estimates are thereby more uncertain and could change.

Most projects are implemented without cost overruns

Figures for the 66 projects with approved PDOs in 2007-18 show that 83 per cent were completed either within the uncertainty range in the PDO estimate or below. See figure 6. In the order of 73 per cent of the projects were completed in line with the PDO estimate. Just under 17 per cent had cost overruns and 11 per cent saw costs reduced by more than 20 per cent. That includes projects which are still ongoing.

Viewed overall, the projects saw their costs rise by about eight per cent (roughly NOK 75 billion) from the PDO estimate. The category of fixed and floating facilities made the largest contribution to an overall increase in costs for the projects. See figure 7.

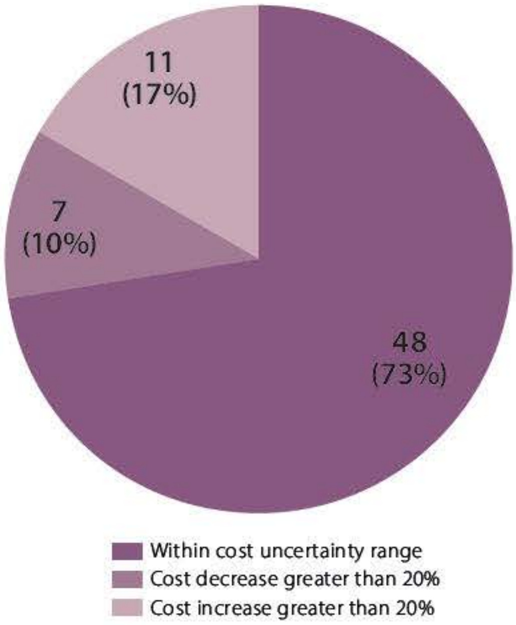

Figure 6 shows the number of projects completed within the PDO uncertainty range (+/- 20 per cent) and the number completed with costs increases/decreases greater than 20 per cent. Total of 66 projects. The figure also includes projects which are not yet completed.

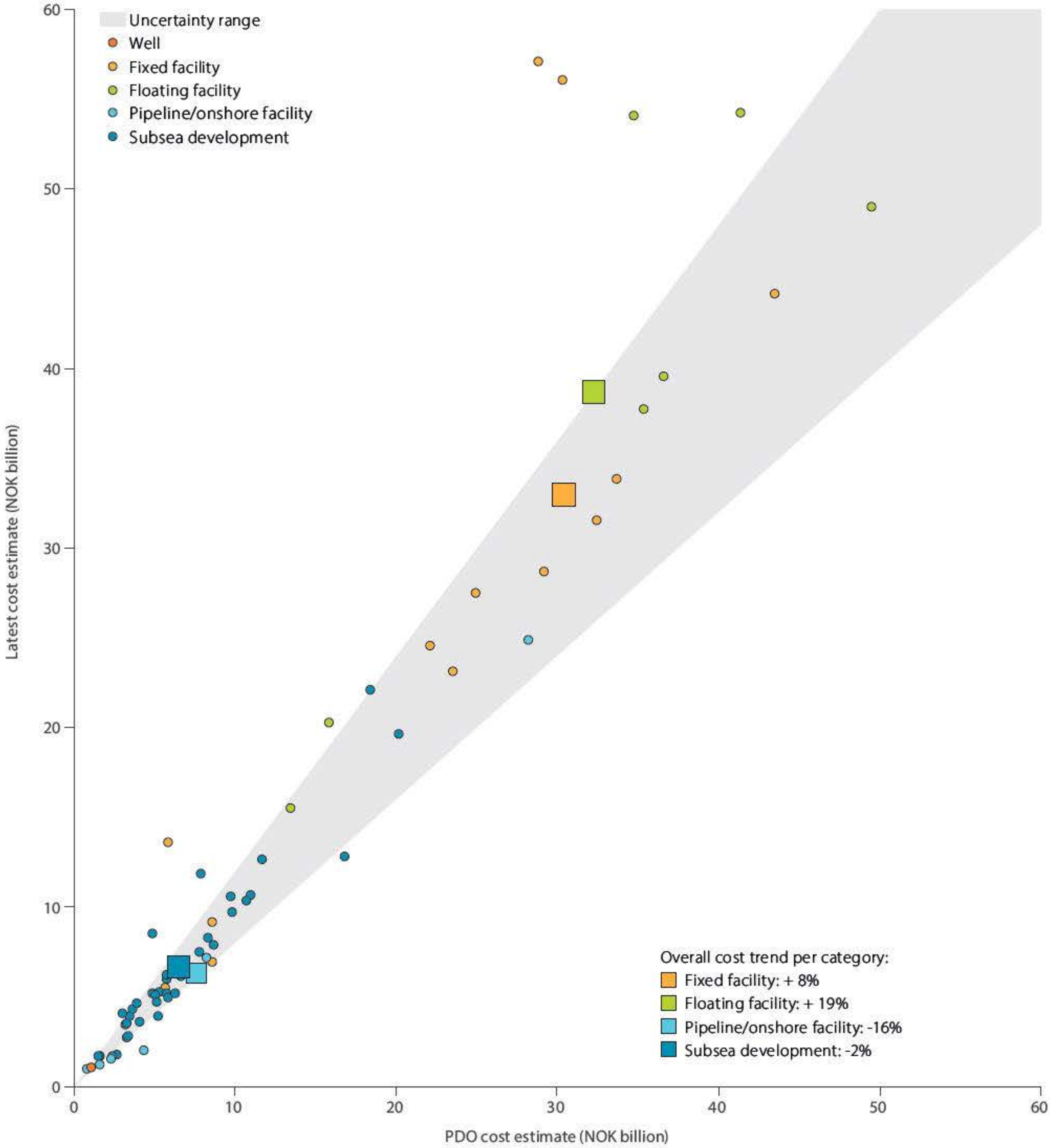

Figure 7 Cost developments for 66 projects in NOK billion in 2019 value by development concept. Each dot represents a project, and its colour indicates the development concept. The squares represent the total cost trend for projects in a development category. Johan Sverdrup phase 1 is not presented as an individual project because of the size of the investment, but has been incorporated when calculating the overall cost trend for the fixed facility category.

Project execution improved from the first six-year period to the second

A comparison of projects approved in 2007-12 and 2013-18 respectively shows that execution in more recent years was better than before. This is illustrated by figures 8 and 9. Projects approved in recent years have hit their cost estimate better, and fewer have had overruns. The final status of developments yet to be completed remains uncertain.

Overall, costs for pre-2013 projects increased by about NOK 115 billion or 24 per cent from the PDO estimate. Eight of the projects ended up with cost overruns – Vega and Vega South, Valhall Redevelopment, Skarv, Yme, Goliat, Brynhild, Jette and Martin Linge. Of these, Martin Linge is still not on stream and Yme was terminated without being completed. Two projects in this period – Troll P-12 and Troll B gas injection – witnessed a cost reduction of more than 20 per cent.

The post-2013 projects saw an overall cost reduction of NOK 40 billion or eight per cent from the PDO estimate. Three had cost overruns – Flyndre, Varg gas export and Njord Future. No less than six competed projects – Oseberg west flank 2, Maria, Ekofisk 2/4, Sverdrup construction stage 1, Edvard Grieg oil pipeline and Rutil in Gullfaks Rimfaks Valley – reduced costs by more than 20 per cent.

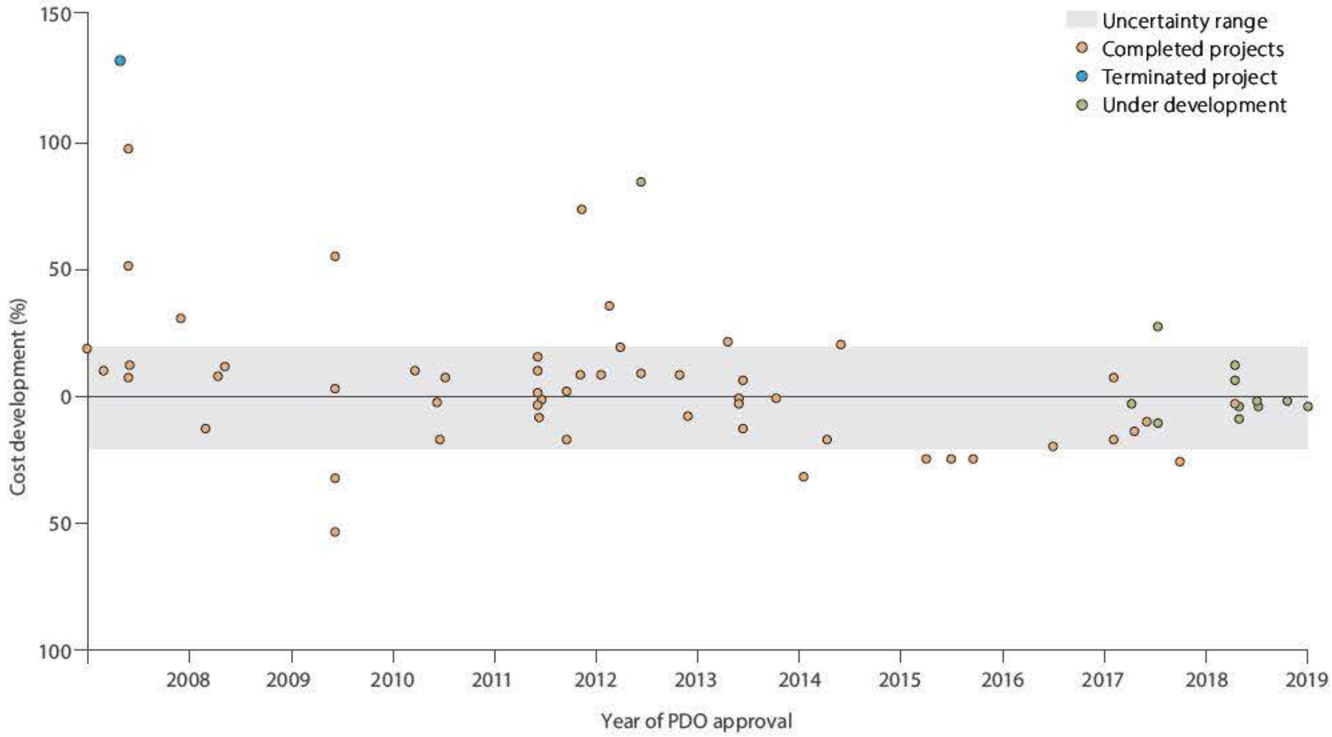

Figure 8 Cost trends for development projects (percentage change from the PDO estimate) compared with the year of official PDO/PIO approval.

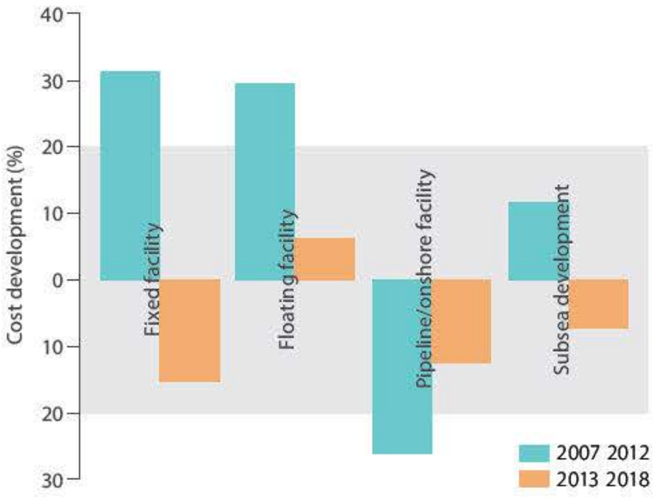

Figure 9 Overall cost trend for development projects by development concept. The grey area shows the normal +/- 20 per cent uncertainty range in the cost estimates.

4.2.1 Fixed and floating facilities

This section looks in more detail at cost trends for developments based on fixed or floating facilities. A total of 21 projects fall into that category. Figure 10 provides an overview of their cost performance in per cent.

For the period as a whole, 71 per cent of the projects (15 of 21) ended up within or below the uncertainty range for costs. Six had cost overruns, and one reduced costs by more than 20 per cent.

Most projects with overruns had their PDO approved before 2013. Since 2013, only one project has had overruns – Nord Future, currently under development. Johan Sverdrup phase 1 had savings of 24 per cent (about NOK 31 billion). Several of the projects with large overruns were covered in the NPD's 2013 report.

Topside costs for many projects are more than 20 per cent above the estimate, but the total cost may nevertheless remain within the uncertainty range. This will often be the case if the project manages to stay on schedule and costs for other elements are below the estimate. Examples are Gina Krog, Ivar Aasen and Edvard Grieg.

Major modifications and upgrades of existing facilities could help to increase complexity, since

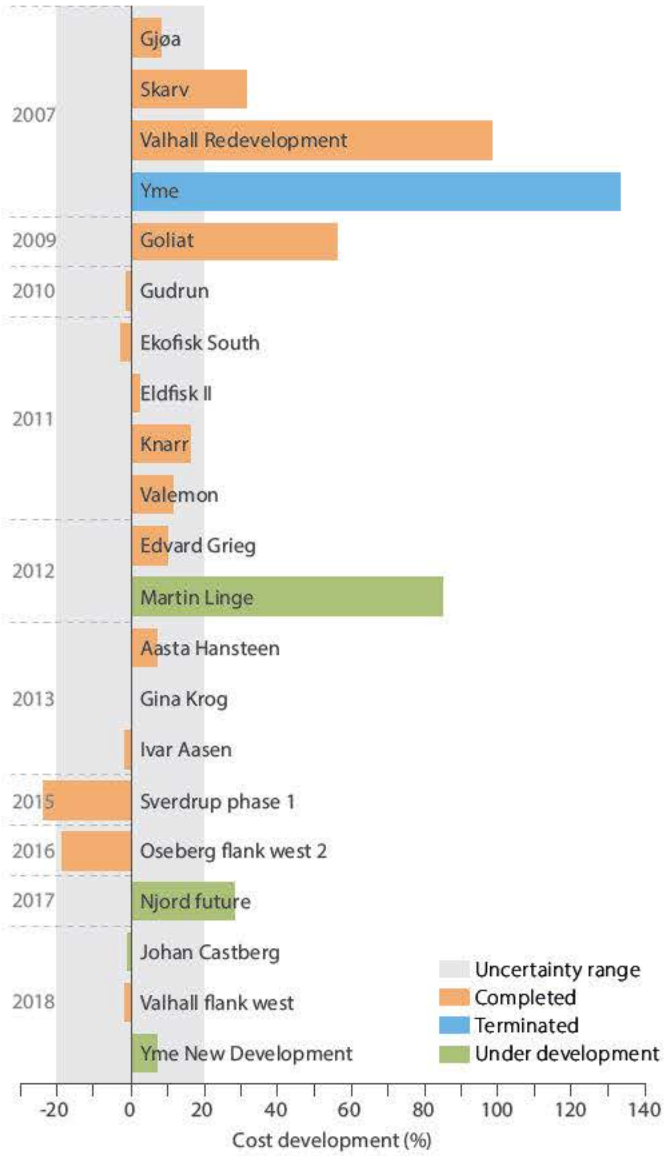

Figure 10 Cost changes in per cent for development projects involving fixed or floating facilities.

the condition of the facility may be uncertain. Njord Future involves upgrades and modifications to both the Njord A production facility and the Njord B storage ship. Converted tankers were chosen as storage ships for both Gina Krog and Martin Linge rather than building new vessels. Both were significantly delayed.

Estimates for the steel jackets on fixed platforms are normally good. Floater hulls have experienced cost increases in some projects. That applies to both Goliat and Aasta Hansteen, where the hulls were larger and more complex than with similar earlier concepts. The hulls for Skarv (apart from the turret) and Gjøa were cheaper than estimated.

Erroneous assumptions about the krone exchange rate in their PDO contributed to a substantial cost increase for several projects. Aasta Hansteen, Martin Linge and Johan Sverdrup phase 1 suffered foreign exchange losses of several billion kroner. Despite negative currency effects for several of the projects approved in 2013 and later, these had an overall cost reduction of about NOK 40 billion.

4.2.2 Subsea developments

This section takes a closer look at cost trends for subsea developments. A total of 38 projects fall into that category. Figure 11 presents an overview of their cost performance in per cent.

Ninety per cent of the projects ended up with costs within the PDO uncertainty range or below. Seventy-nine per cent (30 of 38) were completed to the budget presented in the PDO. Four (10.5 per cent) had cost overruns and four were below the uncertainty range. The proportion completed to the PDO estimate was larger than for fixed and floating facilities.

A further improvement has also been achieved in recent years. Most projects with a PDO approved post-2013 are set to end up with costs lower than estimated. Only one of these 16 – Flyndre – has so far had a cost increase above the PDO range, and no less than three – Maria, Rutil in Gullfaks Rimfaks Valley and Ekofisk 2/4 VC – have seen costs reduced below it.

In connection with the cost trends reported annually in Proposition 1 S, the MPE provides a brief summary of the reasons for any changes to cost estimates. A review of this summary for subsea developments shows no clear reasons for the cost variations.

Work on a producing facility calls for good planning to limit the impact on day-to-day operations. Estimating the scope of the modifications can be demanding. Nevertheless, the NPD has not found this to be an area where the projects fail to succeed more often than others. However, three of those

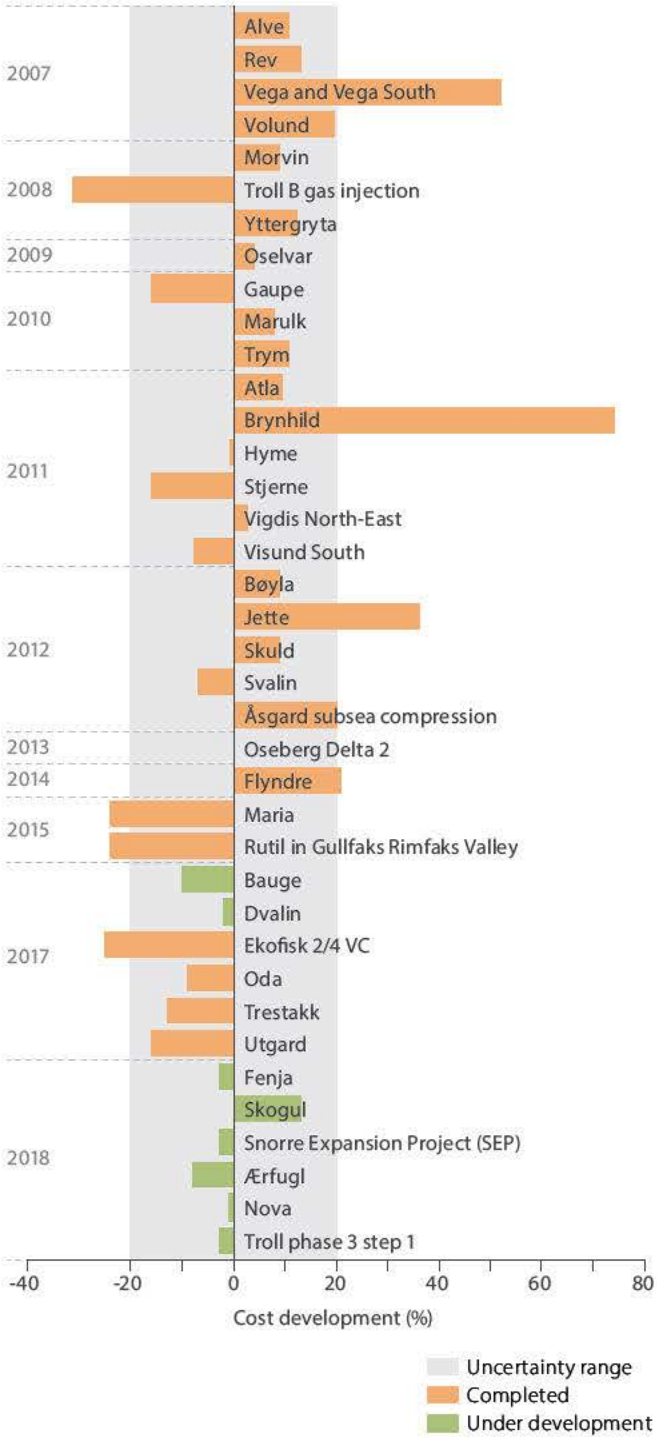

Figure 11 Cost changes in per cent for development projects involving subsea installations.

with cost overruns – Jette, Flyndre and Brynhild – reported modifications as a source of overruns.

A common denominator for the four projects which reduced costs by more than 20 per cent is that drilling proved cheaper than the PDO estimate. Maria, Rutil in Gullfaks Rimfaks Valley and Ekofisk 2/4 VC all benefited from industry improvements related to drilling efficiency in recent years.

4.3 Schedule

Figure 12 shows the deviation between scheduled and actual start-up for completed projects. A majority came on stream within a reasonable time, but the overall average delay in relation to the schedule was about 3.5 months. Some individual projects in particular took significantly longer. Martin Linge is not included in the base data since it remains uncompleted. Nor has Yme been included since it was halted in December 2012 without being finished. That corresponded at the time to a delay of about four years from the planned start-up date.

The average delay for fixed and floating facilities in 2007-18 was just under seven months. Four of the projects – Ekofisk South, Eldfisk II, Johan Sverdrup phase 1 and Valhall flank west – were completed before or on schedule. Projects approved in 2013 and later did better than in the preceding period, with an average delay of 3.5 months.

Subsea developments experienced an average delay of just under two months. Projects approved in 2013 and later again did better than in the preceding period, being completed on average two months ahead of schedule rather than three months behind.

When developing a field, many interdependent activities must be planned and executed. Great uncertainty could exist over the duration of these and over delays which might propagate further through the project. A planning risk analysis is normally carried out to identify how different risks could affect the schedule. That forms the basis for establishing a probability distribution for when the project could be completed and a best estimate for coming on stream.

In order to meet the expected start-up date when building facilities with a large amount of offshore work (such as topsides installation and hook-up), it is generally important to ensure that departure from the yard occurs in spring or early summer. Much of the installation work is weather-sensitive and must occur between April and September. A few months of delay from the yard could thereby put the project a whole year behind schedule.

Subsea developments also depend on a sufficiently good weather window for carrying out certain

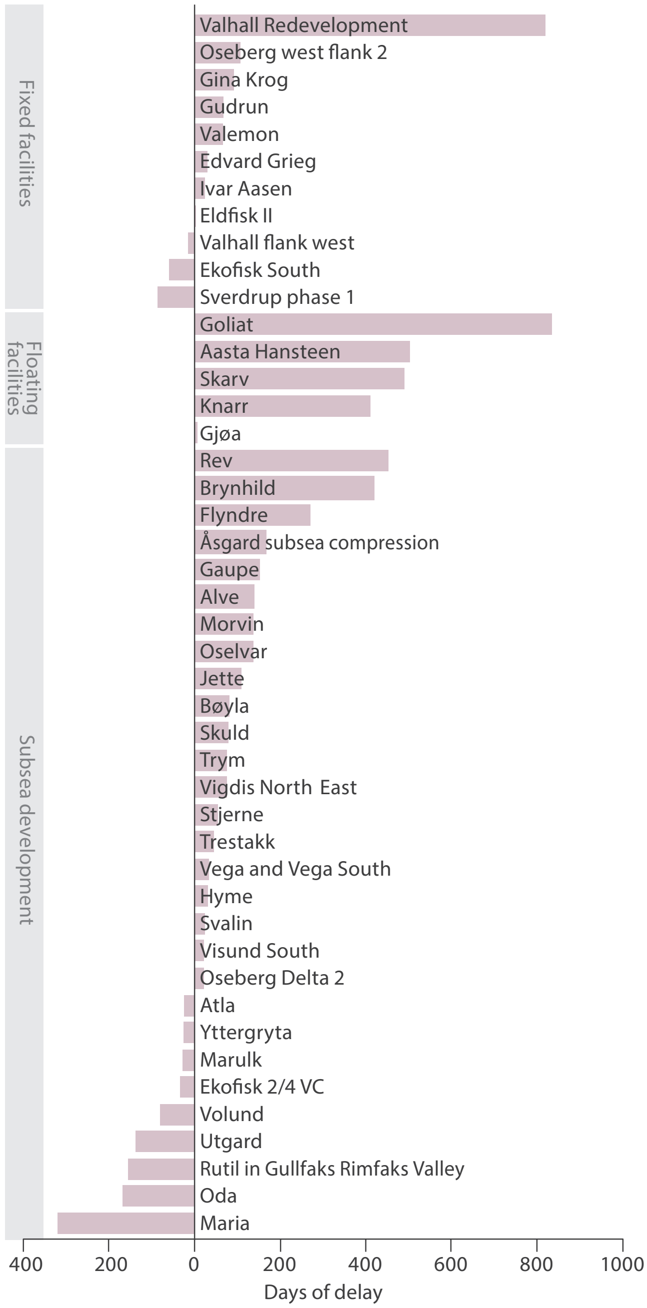

Figure 12 Number of days of delay by project and development concept. Ongoing projects are not included. Projects with a negative number of days have come on stream ahead of schedule.

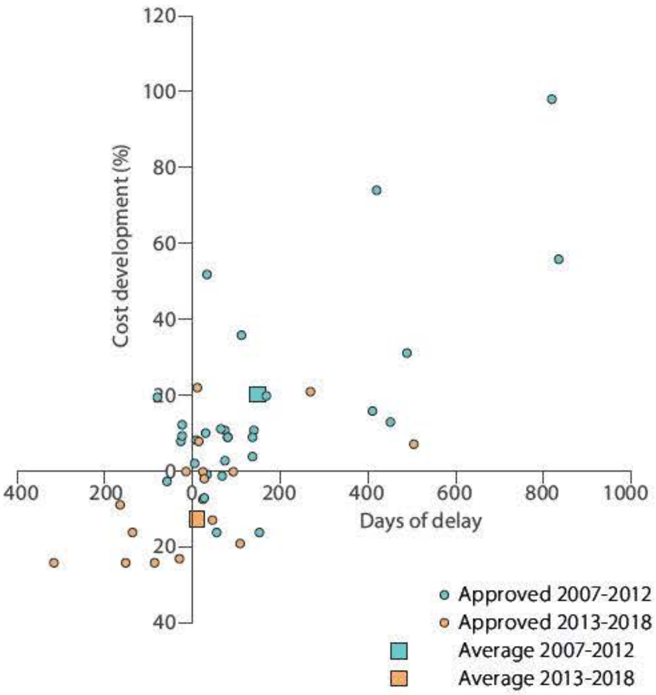

Figure 13 Variation from the planned start-up date for completed projects compared with changes in costs for projects with a PDO approved in 2007-18.

activities, but are less vulnerable if some deliveries are delayed.

Figure 13 shows that a relationship exists between delays and cost developments. The spread in the numbers is relatively large. This could be because cost increases and delays occur only in parts of the work, while possible savings are made elsewhere. Contractual relationships as well as the operator's project portfolio and opportunities to swap installation activities and vessels are also significant here.

4.4 Regularity

Development projects may often be assessed on the basis of development costs and execution time. However, it is also important that the facilities can be operated in a good way and that production takes place as expected.

Regularity, field lifetime and the level of safety can be affected if equipment which has been fabricated and installed fails to meet the desired quality. Based on a review of reported production from the fields as well as information about operating experience provided in the annual status reports, the NPD's assessment is that projects with cost overruns and delays have an increased risk of lower uptime after coming on stream. This could be because production facilities have not been fully completed when these fields start up.

Goliat, Skarv and Knarr are examples of projects which spent significantly longer than planned in the execution phase, and where regularity was been low in the first two years after coming on stream. Various types of work and system testing have been needed on these fields after starting production.

4.5 Changes to reserves

Being able to produce oil and gas resources in accordance with or better than the plans is a very important indicator of success for a development project. In the PDO, the operator describes expectations for resources in place and recoverable reserves. These estimates are given as an expected value with an uncertainty range from low to high.

A study from the University of Stavanger has compared actual production during the first four years on stream with the operator's PDO estimates /8/. This work covers 56 oil developments on the NCS from 1995-2017. One conclusion is that production from the projects during their early years on stream is for the most part overestimated, and that only 25 per cent of developments have ended up with output inside their uncertainty range during the first four years.

At the same time, the NPD's data reveal that many fields will yield more over their producing lives than the amount which formed the basis for their development. The *Resource report* for 2019 /4/ shows that field reserves have increased substantially in recent years. Generally speaking, there has been a trend for reserves to rise in the larger fields and decline for smaller ones. The resource report notes that there could be several explanations for this. Licensees with large discoveries often take a development decision based on the resources needed for profitability, and a flexibility is built in which allows additional resources to be realised over time.

About a third of the 66 projects covered in this report result from the licensees seeing opportunities to initiate measures which yield additional resources in producing fields. An example is Vigdis North-East, the third PDO on the Vigdis subsea development.

About two-thirds of the projects involve developing new fields – in other words, the first PDO for the discovery. Figure 14 presents reserve changes since the PDO on these fields, which are divided into large, medium-sized and small. Several of the small fields have seen a substantial percentage decrease in their post-PDO reserves. One example is Maria, where production experience and data acquisition have established that volumes in place and reservoir properties differ from those described in the PDO. The licensees are working on measures which could increase reserves from the reduced 2018 estimate.

Drilling many appraisal wells before a PDO is often not considered beneficial on small fields. This means that the decision base may be relatively more uncertain than for larger discoveries. It is therefore important that licensees planning to develop small discoveries maximise data acquisition from production wells and other sources in order to improve understanding and reduce uncertainty. A possible measure could be to reduce the number of predrilled wells, and instead drill some of the wells after production has begun.

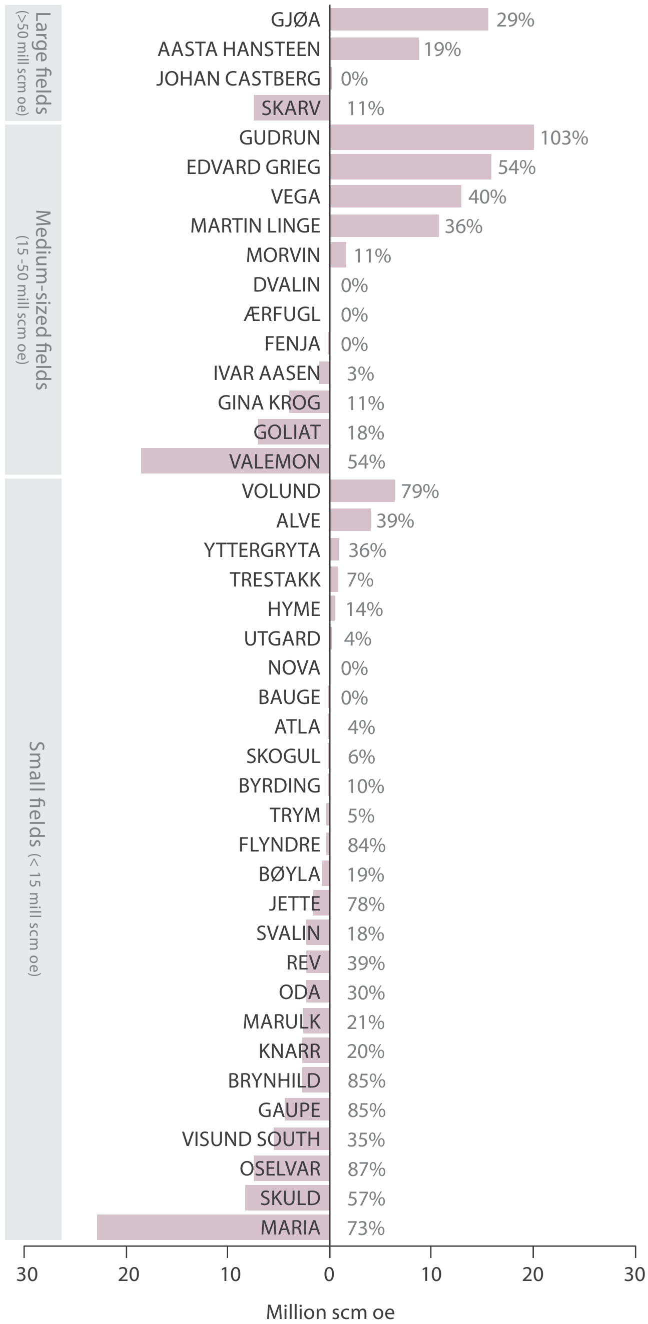

Figure 14 Reserve changes (million standard cubic metres of oil equivalent – scm oe) compared with the PDO for projects covered by the report. Only those representing the first PDO on the field are included (not further development and improved recovery projects). Johan Sverdrup is excluded because of its size (up by 130 million scm oe when phase 2 was sanctioned). Reserve changes based on historical production and remaining reserves on the 2018 resource accounts.

5 Project experience

The NPD has held a number of meetings since 2014 with development operators. These sessions report on progress and cost trends as well as challenges, and how these are being tackled. Lessons learnt and experience gained are summarised and applied in the NPD's early-phase follow-up of projects to help licensees take account of important factors for achieving good execution.

Another key purpose is to share experience with the industry. This chapter therefore covers important experience and lessons from the developments. These are primarily based on meetings held by the NPD in 2014-19, but other studies dealing with the subject have also been referenced.

This chapter is divided into different topics which discuss and provide examples of experience and learning considered by the NPD to be important for successful project execution. However, the specific project examples in the chapter do not provide a complete explanation of why a project has been successful or less so. The PSA published a detailed review in 2019 covering three of the developments in the period covered by this report /5/.

5.1 Detailed planning before the PDO

The planning phase precedes the investment decision and submission of the PDO. See figure 1. In the NPD's 2013 report, several of the projects reviewed were found to have major deficiencies in this phase. Several were characterised right from the start by a much too ambitious execution plan. Little time was thereby also allocated to early-phase work. Experience shows that projects which fall short in this area need to make extensive changes during the construction phase and to repeat work. The result is then often overruns and delays.

Various development concepts are matured up to the BOV, when the licensees choose one of them and decide whether to continue pursuing the project. Making integrated and detailed assessments and taking the right choices in the preceding phase reduce the risk of post-BOV changes. This assumes that the decision basis is sufficiently matured and that good cross-disciplinary interaction prevails in the project team so that concept changes are avoided at a late stage. The concept should permit action to be taken if the sub-surface proves to differ from earlier assumptions – altering well locations, for example. Should many issues remain unclarified at the BOV, sticking to the plan may prove very resource-intensive and this could have consequences for project execution. The licensees should consider whether it might be better to postpone a BOV until basic uncertainties are clarified.

During the post-BOV phase, the chosen concept is matured to an investment decision and PDO. Sufficient time should be allowed for studies to ensure good-quality documentation for the execution phase. A good rule is to try as far as possible to avoid introducing significant changes in the concept after the BOV. If alterations have to be made, enough time must be allocated for maturing these to the right level before the project is sanctioned. Goliat is an example where the decision base was inadequately matured at both BOV and PDO /5/. Experience from Martin Linge is rather similar.

The NPD finds that many projects developed in recent years or still in progress highlight good planning as the reason why execution has gone well. Operators report that they handle surprises effectively during the execution phase because of the preparation made at an early stage.

As described in section 3.2, greater attention is being paid to an early choice of concept. If this helps the operator to allow more time for maturing the chosen solution, it could improve the quality of the decision basis. However, a balance needs to be struck between making an early choice and maturing the alternatives sufficiently to ensure a good selection.

Project organisations appear to have learnt the lessons from a period with many examples of cost overruns. In addition, market changes have influenced the way companies plan their projects. Levels of activity and prices were high up to 2014. The oil price slump caused licensees to devote more attention to costs and cost efficiency – projects also had to be profitable at low oil prices. Certain licensee groups decided during this period to devote more time to planning to ensure profitability under the new conditions. The extra time was used to mature the project further and to make improvements before the execution phase. Developments sanctioned since oil prices fell have often benefitted from greater availability of capacity at suppliers and higher priority at construction sites. Should the downturn lead to downsizing by suppliers, however, the consequences could be negative for capacity as well as for HSE and quality. In some cases, a risk has also existed that suppliers could go into liquidation.

Dvalin and Oda are two subsea developments where the operators have emphasised good planning as the reason why project execution has gone well.

Based on input from Equinor and Total

Martin Linge

The development concept for Martin Linge is a fixed facility with processing and oil transfer to a floating storage and offloading (FSO) unit. The gas is exported to the St Fergus terminal. Wells are drilled by a separate jack-up rig, and power is supplied from shore.

Project status

Total was operator for project planning and development until its interests and the operatorship were transferred to Equinor in 2018. The latter now holds 70 per cent, while Petoro has 30 per cent.

In Proposition 1 S (2019-2020), Equinor reported that the cost estimate has risen by almost NOK 26 billion or 85 per cent since the PDO to NOK 56 billion. Production is now expected to start in the third quarter of 2020, compared with the PDO estimate of December 2016.

Project experience

The authorities were informed in October 2011 that the licensees had passed the BOV milestone, with the PDO submitted in January 2012.

Feed work had not been completed at the PDO. The concept of power from shore was introduced in 2011 and identified as an execution risk in the PDO, since design changes came late and the solution had not been studied in detail. Another risk was the weight of the process module in relation to the capacity of the crane vessels available at the time.

The jacket contract was awarded immediately after PDO submission. Contracts for the FSO, topsides and subsea equipment/flowlines were placed in early 2013. According to the 2014 national budget (based on reporting to the MPE in August 2013), the investment estimate had risen by NOK 3.4 billion because of higher costs in a tight market, the subsea installations, more extensive engineering, a bigger project organisation than originally planned and power from shore.

When the PDO was submitted, plans called for the topsides to be installed as three modules – the quarters and utilities, the well and process module, and the flare boom. The quarters and utilities were built separately with the intention of hooking these up and testing the systems before offshore installation in a single lift. Estimates for the maximum permitted lifting capacity were reduced post-PDO. Combined with a weight increase, this contributed to a conclusion that quarters and utilities had to be installed separately. It was then discovered in 2012 that the process module exceeded lifting capacity and had to be split into a further module, which was connected to the flare boom. Topside structures also needed to be removed before lifting the modules. These factors meant that integration work originally due to be done at the yard had to be carried out offshore. Weight challenges are therefore an important reason why hook-up and completion work offshore is taking significantly longer than with other developments.

Technip and Samsung Heavy Industries (SHI) were awarded a turnkey contract for the topsides, including transport to Norway and offshore hook-up/completion. Total also found, like many other operators, that the engineering hours needed were significantly above the estimate. Constructing the topsides in South Korea proved challenging, both because of engineering delays and because many competing projects at the yard made the resource position challenging.

The licensees decided to postpone the planned departure of the topside modules from the summer of 2016, initially by a year until the summer of 2017.

An audit of Martin Linge at SHI conducted by the PSA in March 2017 focused on technical safety, electrical facilities and maintenance management. Several breaches of the regulations were identified with the modules.

In addition to challenges caused by a big workload and quality shortcomings, construction work was temporarily halted by an accident at the yard on 1 May, when six people employed on the Martin Linge project died. Departure from SHI was postponed until the end of 2017.

The process and utility modules were positioned at the Rosenberg yard in Stavanger from March 2018 for inspection and verification before being taken offshore in July 2018.

Apply Leirvik was awarded the quarters contract as an SHI subcontractor. Lack of capacity meant that engineering and fabrication were moved from Stord to Apply Emtunga in Gothenburg. The quarters module was transported to Norway in 2018.

The FSO solution had not been determined in the PDO. Shipping company Knutsen was awarded the contract to convert tanker *Hanne Knutsen* for this role in Poland. The work was challenging and very delayed.

Delays related to the FSO and quarters never became critical for Martin Linge.

Offshore hook-up and completion, estimated in the PDO to last seven-eight months, could take about two years under current plans. The higher workload substantially increases the hours required. This rise has occurred partly because the modules were incomplete when they left the Asian yard and because additional work has since been identified through systematic system reviews. Topsides design combined with weight challenges has also contributed to additional hours offshore by limiting opportunities for testing and hook-up on land. Efficiency on the field has also been lower than expected.

Photo: Equinor/Arne Wold/Bo B. Randulff

Based on input from Spirit Energy:

Oda

Oda is a subsea field in the North Sea comprising a seabed template with two production wells tied back to Ula and an injection well for pressure support. Spirit Energy (formerly Centrica) is the development operator. The PDO was approved in 2017.

This project is the operator's first development on the NCS. Acquiring expertise and maturing through Feed have been important in the preparations. Spirit had meetings with other operators and industries in order to establish a best practice for project planning and execution. Alliances were entered into in 2015 with a few selected contractors. This was prompted in part by a desire to involve the suppliers early in the planning phase, to give them greater ownership and involvement, and to ensure supplier continuity from Feed to detail engineering and construction. According to the operator, another consideration was that it would help its own organisation to be more easily adapted and scaled to the level of activity.

Low oil prices in 2016 meant that about six additional months were required before the Oda project was sanctioned internally and in the production licence. In addition to increased requirements for checking and maturity in the design work, all commercial agreements – such as tie-back to the Ula host platform – were to be in place before sanctioning. A high level of maturity in the Feed studies and using the same contractors from Feed to detail design meant no post-PDO changes were made.

The field came on stream in March 2019, five months ahead of schedule and NOK 500 million under the PDO cost estimate. Results from production drilling have shown that the reservoir is more complicated and less extensive than expected. This was a sensitivity in the PDO volumes. Reserves have been written down by 30 per cent. However, the Oda template has a spare well slot, and opportunities for increasing and/or accelerating reserves have been identified.

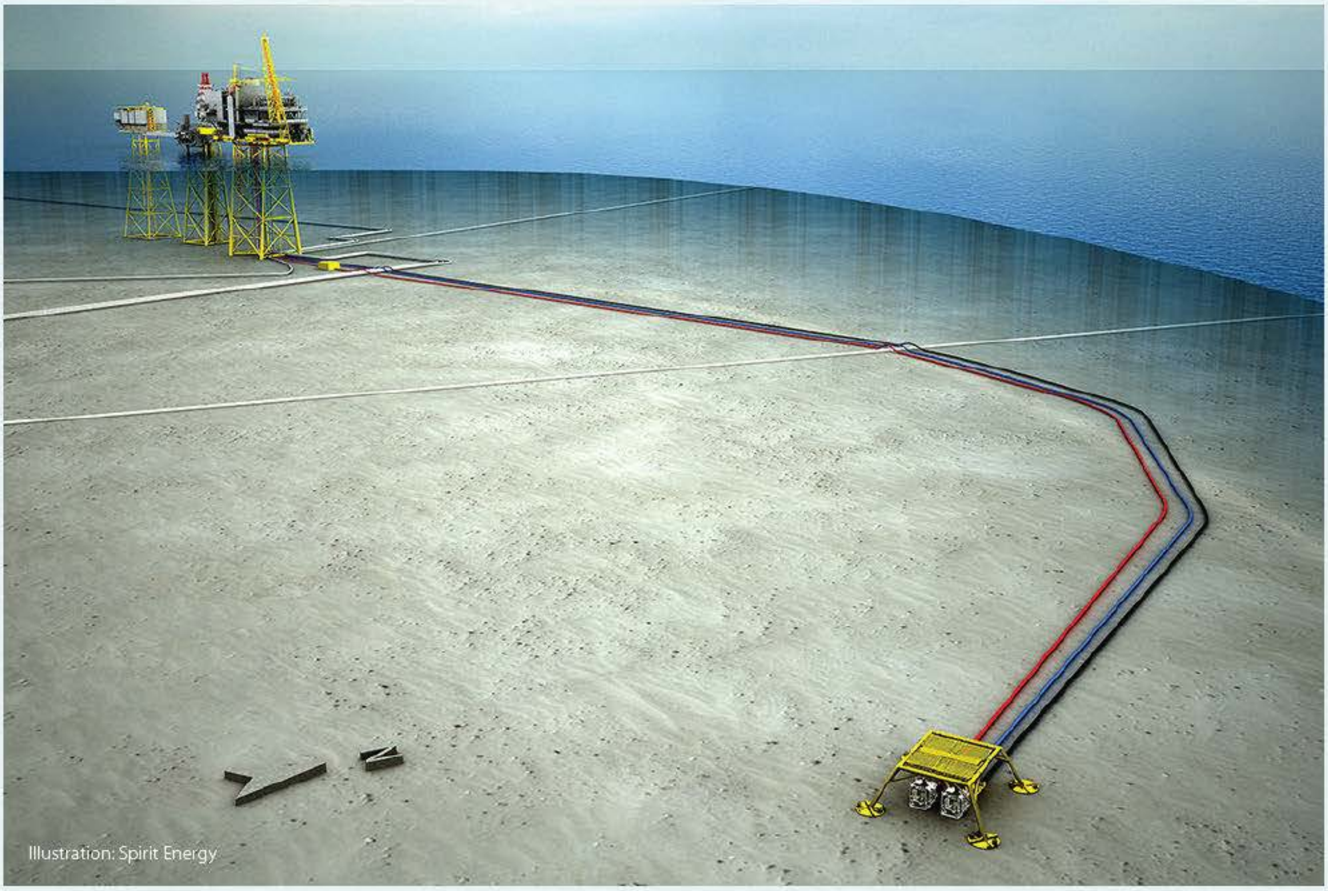
Illustration: Spirit Energy

5.2 Project organisation with enough expertise, experience and capacity

Equinor is the largest development operator on the NCS and has pursued such activities for many years. The company has both large and small projects under way at any given time. It works actively to learn lessons from these developments and continues to refine working methods and governing documentation. The same applies to ConocoPhillips, which has had a portfolio of projects in the Ekofisk area over many years.

Other operators have pursued few NCS developments. In other words, companies making discoveries off Norway may have very different starting points when a project is to be planned and executed.

Figure 15 shows that Equinor has had few cost overruns on projects involving either subsea installations or fixed/floating facilities. Similarly, the remaining operators have been successful with subsea developments. Five of 12 projects based on fixed/floating facilities have ended up with overruns – Skarv, Goliat, Valhall Redevelopment, Martin Linge and Yme. Examples of projects without overruns are Ekofisk South, Eldfisk II, Edvard Grieg and Ivar Aasen.

Companies which have had few or no earlier developments must build up a project organisation, including possible governing documentation, while also pursuing planning work. Several of the project teams which the NPD has held meetings with emphasise the importance of inexperienced development operators building up an organisation with experienced project personnel. That applies particularly where a stand-alone field centre is involved. Such projects call for a big organisation with a number of disciplines, since they involve a number of interfaces requiring a large degree of involvement and management by the operator in both planning and execution phases.

When subsea developments have the same operator as the host facility, modification work on the latter is organised as an integrated part of the project. Where the operators are not the same, two project organisations are established with the operator of the host facility responsible for the necessary modifications. Collaboration between two operators differs from relations between oil company and supplier. The operator developing the field has limited opportunities to manage the part of the work which lies on the host facility. This makes it important, when planning a project, for the players to establish good routines for interaction and exchanging information, so that a sound basis is created for planning, execution and operation. In the NPD's view, this type of collaboration functions well on the NCS.

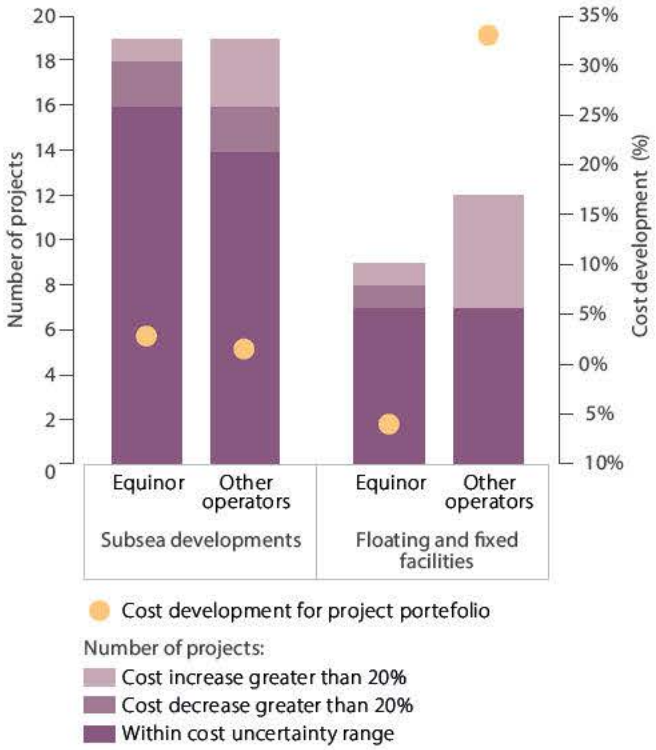

Figure 15 Projects and project results by operator (Equinor and "other") and development concept (subsea installations or fixed/floating facilities).

In meetings with the NPD, several operators have emphasised the importance of good collaboration in the planning phase, independently of possible parallel commercial discussions. Some operators have found that collaboration has generally been more demanding before commercial agreements are in place than in the execution phase.

Based on input from Wintershall Dea:

Dvalin

Dvalin is a subsea development in the Norwegian Sea which comprises a seabed template with four gas producers tied back to the Heidrun platform. Gas is exported in a new pipeline to Polarled. The development operator at the PDO was DEA Norge, which merged in December 2019 with Wintershall Norge to form Wintershall Dea Norge.

This field represented DEA's first development. It was important for the operator to prepare well for the execution phase. In the DEA case, this involved establishing necessary project management procedures and systems. Experience transfer from other operators formed an important part of these preparations.

Aker Solutions and IKM each performed Feed studies related to the subsea installations. A Dvalin PDO was postponed in 2014 because the project was not considered sufficiently profitable. It also took time for the operator to establish a tie-in agreement with the host facility. The PDO was submitted in 2016 and approved in 2017.

The operator utilised these two years to mature the project further and prepare for the execution phase. To create the best possible conditions for competitive tendering and the subsequent execution phase, the operator gave suppliers who had not conducted Feed the opportunity to acquaint themselves with the project.

Dvalin has a reservoir with high pressure and temperature. Only Aker Solutions was originally qualified to deliver subsea equipment for the higher temperature. The operator therefore used the two-year postponement to give FMC and OneSubsea the opportunity to qualify the necessary components. Tender evaluation was completed and the contract ready for signing at PDO submission. That helped to reduce uncertainty in the PDO cost estimates.

DEA emphasises that a close collaboration with the host facility is important for success. As Heidrun operator, Equinor contributed in the planning phase with quality assurance and suggestions on part of DEA's work. Ahead of the investment decision, the parties established a collaboration procedure which defined areas for interaction and information flow between the projects. Furthermore, DEA has been represented in the modification project which Equinor was responsible for. That helped to make DEA very familiar with the status of that part of the work.

The project is still in progress and on target to reach production start-up as planned in 2020.

Photo: Wintershall Dea/Screenstory

5.3 Including experience from project execution and operation in planning work

It is important that the project organisation understands lessons learned from other projects. That could relate, for example, to suppliers, project follow-up and contract strategies. Also important will be knowledge of Norwegian conditions and how these should be taken into account when establishing an execution strategy and timetable, when training personnel, when prequalifying and when evaluating contractor bids.

In meetings with the NPD, many operators have emphasised experience transfer from earlier and ongoing developments as an important part of project planning. That applies to both inexperienced and very experienced development operators. It seems to the NPD that licensees on the NCS are very willing to share experience. This represents an asset for Norway's petroleum industry, and retaining it is important.

Devoting attention in an early phase to minimising offshore hook-up and testing is important. Solutions should be chosen and plans laid which permit as much testing and completion as possible to be done on land. Restrictions on personnel numbers (berths) are greater offshore and access is more difficult. More work offshore as a result of faults and deficiencies which are not rectified before transfer to the field could also impose big extra costs and delays. The same applies if insufficient allowance has been made for possible weight increases during execution, so that modules originally intended for installation in a single lift have to be split up.

Operating experience should be incorporated in all stages of a project. During an early phase, it will be important to identify good operational and maintenance solutions. Establishing plans for delivering the facility in an appropriate way to the production organisation is important. Operations personnel must also participate in the project during completion and delivery in order to ensure an efficient hand-over, to become familiar with the facility, and to prepare for the production phase.

Where modification projects are concerned, input from the operations organisation on equipment experience and the condition of the facility is important in ensuring that the requirements for upgrading are adequately assessed and taken into account in the design. Inspections should be conducted where the condition is uncertain or unknown and to verify that the underlying drawings are updated. The scope of work in a number of modification projects has increased because the estimates failed to take sufficient account of the need to replace and update equipment.

5.4 Contract strategy tailored to expertise and capacity of operator and supplier

One of the recommendations in the NPD's 2013 project report was the need for a clear contract strategy which helps to ensure quality and progress. The operator's follow-up and prequalification of suppliers should be part of this strategy. Thorough supplier prequalification on the basis of earlier experience can reduce the risk of problems along the way and thereby the amount of follow-up required. The review showed that, in several cases, operators relied far too much on the ability of the contractor to deliver in line with the specified requirements.

The significance of ensuring continuity of main contractor(s) from Feed before the PDO to detail design afterwards has been highlighted by several development operators in meetings with the NPD. This helps to ensure that suppliers are familiar with the project when detail design starts and have ownership of the chosen solutions. If a supplier is changed, the schedule must provide time for the newcomer to become familiar with the project and have the opportunity to take ownership of earlier work. Changes will occur more often with a change of contractor, and time must be allowed to handle these.

To ensure continuity of suppliers and competition, operators have often opted for parallel Feed studies. One example is Fenja, a subsea development being tied back to the Njord facilities. The licensees chose parallel Feed studies for both subsea installations and pipelines. Fenja's development concept involves building and installing a new type of heated pipeline. The two suppliers could each offer their own variant of this concept, which both required technological qualification. Parallel studies increased the likelihood of success with such qualification while also securing competing tenders. Where the subsea installations were concerned, parallel Feed gave both suppliers good insight into the project and the best possible basis for a realistic bid.

Many parallel studies in each technical discipline increase costs, can be more demanding to follow up, and make big demands on expertise and capacity in the project organisation. Allocating time after the studies to ensure that sufficient quality has been achieved should be considered, particularly for large developments. In the alliances which certain operators have established in recent years, the supplier is involved early in the planning phase. This form of contract ensures continuity from planning through execution. The operators report that they save time on competitive tendering processes as well as eliminating the risk associated with changing supplier along the way. The idea is also that interaction between the alliance partners over time can help to improve project planning and execution.

Many large developments have been pursued on the NCS since 2007. A lot of these have been awarded as turnkey contracts to yards in South Korea and Singapore. They are usually placed with a consortium comprising a European engineering contractor and a yard. The latter will historically have drawn most of its experience from building ships, which are less complex than offshore process platforms. The work was made even more demanding by late delivery from the engineering contractor. In many cases, the operator also lacked sufficient understanding of the cultural and organisational differences between yards in this part of the world and familiar partners in Norway. These were underestimated when the licensees awarded contracts to Asian yards.

By allocating additional resources for follow-up, Equinor and Det Norske ensured that the topsides for Gina Krog and Ivar Aasen respectively were completed on schedule.

When choosing a construction site for Edvard Grieg, Lundin emphasised that the suppliers needed to have the right understanding of what was required and made its own estimates of how many hours would be needed to build the topsides. The supplier whose estimate was in the same order of size as the operator's was chosen, rather than the competitors who had tendered lower costs but with estimates for total work hours which the operator considered unrealistically low. According to Lundin, less follow-up was needed than would have been the case with an Asian yard. Since Edvard Grieg was sanctioned before several other large projects in a period characterised by a high level of activity, the company had greater freedom of choice over a yard than a number of other operators.

Turnkey assignments have been the most frequently used form of contract for building platforms on the NCS among the projects covered in this report. Equinor is the operator with the largest number of projects involving construction in Asia. Most have been EPC contracts. In recent years, contracts awarded to Norwegian suppliers have been EPCs, while those given to Asian yards have been for fabrication and construction (FC) with the EP parts going to a Norwegian supplier (see table 1 and the description of the Johan Sverdrup project).

A division into several contracts will make greater calls on the operator's experience and resources. That could be demanding for an inexperienced project organisation. At the same time, experience shows that good interaction with and control of suppliers is also crucial when using turnkey contracts. These require close follow-up of progress and quality, a presence at the supplier, and being prepared to take control if a change of course is needed. It is then important that satisfactory mechanisms for collaboration and control are established in the contract, rather than taking it for granted that the contractor will deliver in line with specifications and plans. When operators with limited project experience want to use turnkey contracts, selecting suppliers with a solid ability to implement such assignments will be important.

With Gjøa, the licensees agreed that Statoil would develop the discovery and Gaz de France Norge (GDF) would take over in the production phase. Similarly, the licensees for 7324/8-1 Wisting in production licence 537, where OMV is operator, recently agreed that Equinor would lead the development. As on Gjøa, OMV will take over the operatorship when the field comes on stream. This approach was used on the NCS in the 1980s, before Statoil acquired enough development expertise, and can also be a future model for demanding projects in production licences where the operator has limited development experience.

Contract formats vary significantly between subsea developments, from extensive splitting between different vendors to turnkey assignments. Operators with less development experience use the latter (EPC or EPCI), with possible alliance partners in addition. Equinor tailors its strategy to the individual project and has chosen both to award turnkey contracts and to utilise extensive separation of assignments.

Subsea developments are completed to a large extent within cost and schedule, and such projects appear to have opted for appropriate contract strategies based on the expertise of suppliers and operators.

Norwegian projects with contracts in South Korea

An MSc student at the University of Stavanger wrote a thesis on *Managing the Efficiency of Foreign Engineering Contracts: a Study of a Norwegian and South Korean Project Interface* /9/ in 2015.

This concluded that four principal factors add to challenges for Norwegian EPC projects in South Korea: cultural differences, industrial practices at the yard (shipbuilding), engineering design and quality control, and the EPC contract form.

Understanding the country's culture is important, since it differs significantly from that in the west. Confucianism, a Chinese philosophical tradition, is strong. It influences the understanding of contracts, yard organisation, social relations, and communication both internally and with the client and suppliers.

The thesis noted that South Korean yards have traditionally concentrated on shipbuilding. They have also had many offshore projects, but mostly the fabrication of such structures as steel jackets for fixed facilities and hulls. When the 2008 financial crisis hit the shipyards, the big ones in particular wanted to take greater responsibility for large offshore projects. Transferring the Lean principle, which has helped the yards to achieve high shipbuilding productivity, to offshore production facilities is not entirely straightforward since these are more complex and largely custom-designed. The yards achieve their high productivity at the expense of flexibility. Handling change is challenging. Extensive use of contract labour represents another challenge. Although this helps the yards to be competitive, it gives them less control over resources and quality.

Cross-disciplinary engineering expertise, important for designing and building highly complex structures, is largely lacking at the yards. In addition, the thesis found that the Norsok standards and Norway's performance-based regulations are difficult to understand, which means that users must have the experience and knowledge required to benefit from their advantages.

These considerations make it difficult for the yards to exercise turnkey responsibility in an EPC contract. The thesis also found that, with shipbuilding, the yards normally secure contracts from a shipping company over a number of years. That helps to build long-term relations. Similarly, relationships are built up with sub-contractors. About 85 per cent of equipment and materials for shipbuilding are delivered by local suppliers. These share a common culture with the yard and an understanding of what is to be delivered and how. Where offshore projects are concerned, the operator and the engineering contractor are in many cases new to the yard. A large part of the equipment and material will also be delivered by suppliers the yard is not used to collaborating with. In addition, Norwegian turnkey contracts are formulated differently from shipbuilding orders. This is highlighted as another challenge.

Based on input from Equinor:
Johan Sverdrup

Phase 1 comprises four fixed platforms, for risers (RP), drilling (DP), processing (P1) and utilities and quarters (LQ) respectively. These have been designed and built with the aid of suppliers worldwide. Equinor is the operator, with Lundin, Aker BP, Total and Petoro as partners.

At the BOV, offshore installation was based on traditional crane vessels, which have a lifting capacity of roughly 10 000 tonnes. All the platforms were originally due to be built as several modules and installed by a crane vessel offshore. *Pioneering Spirit*, a new vessel with a lifting capacity up to 48 000 tonnes, was under construction and made topside installation as a single lift possible. Feed studies of both modular and single-lift solutions were conducted in parallel. Midway through this process and before PDO submission, the decision was taken to adopt a single-lift strategy for the DP, P1 and LQ topsides (22 000, 26 000 and 18 000 tonnes respectively). This offered substantial savings in both workload and time for offshore hook-up and testing.

Equinor established a strategy for weight control of the platform topsides early in the planning phase to ensure that the modules were liftable. This included the establishment of margins for both operational weights and lifting capacity, which were followed up in Feed, the detail design phase and the construction contracts. Equipment lists were followed up in detail and quality-assured through benchmarking and by securing experience from other projects. The steel jackets were also designed with robust weight margins, and strict change control was imposed from choice of concept/BOV.

Given the project size and market conditions, Equinor chose to tailor Johan Sverdrup contracts to the market by introducing a greater degree of separation compared with earlier developments. Where two of the platforms were concerned, the engineering contractor was given responsibility for engineering and procurement while construction went to Asian yards to take advantage of their spare capacity and experience from earlier projects. In such a model, Equinor takes responsibility for handling the interface between engineering, equipment deliveries and fabrication, and influences execution in a managed way.

Aker Solutions carried out conceptual and Feed studies before receiving an EPMa contract covering detail design and procurement for the P1 and RP topsides, and an integrated responsibility for design and interface management covering overall construction. Building the P1 and RP topsides was awarded to Samsung Heavy Industries in South Korea under an FC contract.

Aibel secured an EPC contract for the DP topsides and carried out the engineering. The topsides comprise three modules. One was built at Aibel's yard in Thailand, another in Haugesund and the third by Nymo in Grimstad. They were lifted by the *Thialf* crane ship onto a barge in the fjord outside Stord, and then hooked up on this vessel at the Aibel yard in Haugesund.

The LQ topsides were awarded as an EPC contract to a joint venture comprising Kværner and KBR. Engineering and procurement were handled by KBR's London office. Construction took place in Poland and at Stord. Built in aluminium, the quarters were a fixed-price sub-delivery from Leirvik AS. The topsides were completed and tested at Stord before installation offshore.

Hook-up work for platforms and bridges on the field was awarded as two contracts to Aibel and Aker. Two parallel contracts were chosen in order to ensure sufficient capacity and flexibility in executing the complex work of completing the whole field centre. Testing both on land and offshore was planned and executed under Equinor's leadership.

Three of the steel jackets were delivered by Kværner and built in Verdal, while the fourth came from Dragados in Spain. All were awarded as fixed-price EPC contracts.

Phase 2 of the Johan Sverdrup development comprises a new P2 processing platform, an equipment module for installation on RP, and integration work at the field centre. The following main contracts have been awarded for the project.

- Steel jacket for P2: EPC contract for Kværner Verdal
- Topsides for P2: EPC contract for Aibel, with overall responsibility for engineering and interface control for phase 2 at the field centre. The main support frame will be built at Aibel's Thai yard, the upper process modules at Haugesund and the HVDC module by sub-contractor Navantia in Spain. As in phase 1, the modules will be lifted together by a crane ship off Haugesund. Hook-up and testing will be done on a barge berthed in Haugesund before installation offshore as a single lift.
- RP utility module and integration work on the field: joint venture between Aker Solutions and Kværner responsible for engineering, procurement, construction and integration. A 5 000-tonne module will be built at Stord and installed offshore with a crane ship.

5.5 Good routines for quality assurance

Quality assurance is a significant part of early-phase work. Various forms of it are usually conducted during planning, and particularly at the project's DGs. It is important that quality assurance is good enough to pick up possible deficiencies in the underlying material and that follow-up covers their rectification and, where necessary, revision of the plans to allow enough time for this work.

Day-to-day planning and execution of projects is done by the operator. At the same time, the see-to-it duty requires the other licensees to help ensure good quality in the decision basis through participating in management committee meetings, sharing experience and project verifications, and conducting their own and external studies. See section 3.4.

A basic requirement for achieving the right project maturation is that the licensees have a good internal decision system which sets requirements for the level of engineering and cost estimation at the various DGs. One observation in the NPD's 2013 review of the Yme project was that the operator had failed to implement such a solution. Another key requirement is that the companies comply with governing documents and do not sanction projects which are insufficiently mature. Acona's report /5/ concludes that the Goliat project failed to satisfy both Eni and Equinor's requirements for project maturation at both BOV and BOG.

Estimating weights and work hours is important for large newbuild projects, and central to good cost estimating. The quality of estimates will generally improve as more detailed studies are conducted up to the PDO. Comparing the estimated figures with those from other projects (benchmarking) can provide increased assurance of their quality.

Equinor has a big project portfolio which can be used for benchmarking. The company also employs external consultants who have specialised in comparing projects.

Most development operators on the NCS have a relatively small project portfolio, and will therefore have few Norwegian projects to benchmark with. That makes it particularly important for these players to secure external benchmarking.

Many of these companies participate in the Performance Forum, a joint industry project (JIP) where the operators can benchmark their projects. The Forum for Exchange of Experience and Results from Modification Projects (Ferm) is a similar body, which Equinor, ConocoPhillips, Aker BP and Shell belong to.

When oil prices are experiencing big changes, the risk arises that experience data used for cost and planning estimates do not reflect market changes and improvement initiatives (such as drilling efficiency). Inviting tenders for important parts of a project pre-PDO could help to achieve greater assurance of estimate quality. The NPD understands that some companies have requirements in their governing documentation that bids for a substantial proportion of the contracts must have been obtained by the investment DG.

As well as obtaining bids, awarding contracts can further improve the quality of cost and planning estimates. Contractual obligations cannot be entered into until a PDO is approved, unless the MPE consents. In order to receive such consent, the licensees must prove that the disadvantages of postponement are significant. This consent does not represent any form of advance approval of the development plans, and the licensees act at their own risk. See the PDO/PIO guidelines for more information.

5.6 Continuous risk assessment, follow-up and implementation of measures during the execution phase

Project follow-up involves taking care of HSE, following up contractual aspects, ensuring good cost control and progress, managing and following up engineering and construction work, and handling procurement and quality assurance. The division of duties between operator and supplier can vary, and is regulated through the contract. Ultimate responsibility rests in any event with the operator on behalf of the licensees, who must make sure that the project is pursued in accordance with the regulations and approved plans.

Factors contributing to the operator's success in executing the project include maintaining close follow-up from the start, identifying risk and adapting follow-up, as well as taking action if problem areas are identified.

Detail design is the first part of the execution phase, and involves preparing the final construction drawings. It is important that this stage has been completed before fabrication begins. Starting too early increases the risk of faults and of having to redo work.

The number of engineering hours has been underestimated in many large developments, resulting in a significant increase during detail design. That has created challenges related to the progress and quality of engineering and of equipment packages. This will be demanding in any project. In a meeting with the NPD, the operators have stated that Asian yards are efficient at construction when the drawings and equipment/materials are in place.

A high level of activity at yards with many simultaneous projects has contributed to further challenges. Resource shortages, combined with delays to equipment/drawings, made it difficult to stay on schedule. Operators had to fight to secure priority for their project, which was not beneficial for either costs or execution time. Incentive schemes which reward the supplier for progress have been attempted for many projects in a bid to secure resources for their contracts.

To avoid delays, many operators have posted more personnel than planned to the engineering companies and followed up equipment packages more closely through a presence at suppliers for the most critical deliveries. Technical teams with experience of similar projects and Norsok expertise have been established for several developments to help the yards plan their work. Since taking decisions was demanding for the yards because of the challenges with design progress and quality, it has been important for operators to contribute to or manage this interface.

In meetings with the NPD, the operators have also emphasised that relationship-building at top management level is important in securing the necessary priority and communication with the yard. The NPD's understanding is that it has been less demanding to build at yards where the operator is the only customer.

Plans may also have to be adjusted for some projects. Postponing departure from the yard could be relevant, for example. Since weather conditions mean that production facilities on the NCS must be installed in the summer season, a few weeks longer at the yard could mean delaying the start to production until the following season – roughly a year later. Postponements also impose additional costs related to contracts already awarded (crane ships, flotels, drilling rigs and transport vessels).

At the same time, efficiency offshore is significantly lower than on land. Completion work on the field should therefore be minimised to avoid increased costs, delays and the risk of HSE incidents.

When assessing whether plans should be amended, having a realistic picture of remaining work is therefore very important. Acona writes that the Goliat facility was originally intended to spend time at a yard on the Norwegian coast for installation preparations. However, it was decided to go directly to the field. This decision was very likely to have been different if the project organisation had a better overview of outstanding work.

Close follow-up, on-going implementation of measures, assessing their effects and adjusting them along the way are important for any project. The scope of follow-up must naturally be tailored to the relevant development. Operators building at Asian yards, for example, have had from just over 100 to more than 300 of their own employees and contract personnel following up work there. When awarding fabrication contracts for big developments in Norway, experience from some projects indicates that fewer personnel have been necessary for follow-up.

6 Project execution internationally

The EY consultancy published *Spotlight on oil and gas megaprojects* /11/ in 2014. This report studied costs and schedules in 365 projects covering upstream oil and gas, LNG, pipelaying and refineries costing more than USD 1 billion apiece. It found that 64 per cent experienced cost overruns, while 73 per cent suffered delays. The average cost increase was 59 per cent.

The Oil and Gas Authority (OGA) in the UK analysed 58 projects from the 2011-16 period in a report on *Lessons Learned from UKCS Oil and Gas Projects 2011-2016* /2/, published in 2017.

Thirty-eight of the 58 had been completed. These overran their estimated cost and schedule by an average of 35 per cent and 10 months respectively. The corresponding averages for the 20 projects still under way were 20 per cent and 13 months. Subsea developments had the lowest average delay and overrun.

Eleven of the 58 projects were reviewed in more detail with the aim of acquiring and sharing relevant experience with other developments. These projects varied significantly, with some above and others below their cost estimate. Three stood out in particular with overruns of more than 140 per cent.

The OGA published *2018 UKCS Projects Insights Report* /3/ in 2019. This report concluded that project execution was better in 2018. Sixty per cent of the projects were delivered on time, compared with 25 per cent in 2011-16. Developments completed in 2018 met their cost estimates to a much greater extent. The OGA believes the industry has addressed many of the issues identified in its 2017 report. One reason for the improvement is that operators are involving suppliers earlier and now have a better dialogue and collaboration with the suppliers on challenges and solutions. The projects are better defined towards the end of Feed, and the risk registers address uncertainties which must be handled in detail design. A further observation is that the operators are paying greater attention than before to continuity of project personnel from Feed to detail design, which ensures ownership and understanding of the scope of work.

Comparison of conditions on the NCS and the UKCS

Comparing the NPD's findings with the conditions described in the OGA's 2017 report shows that the 58 British projects in 2011-16 had higher cost increases and longer delays on average than NCS developments. According to this report, roughly half the projects were implemented as planned. More than 80 per cent of the 66 developments on the NCS were completed in accordance with the uncertainty range in the PDO or below (the OGA does not define the criteria which must be met in order to accord with the development plans, so the figures are not necessarily fully comparable).

As on the NCS, subsea developments on the UKCS seem to be the project type which is most often executed as planned but with a higher average delay and cost increase. Challenges are greater for stand-alone field developments on both continental shelves. An improvement in project execution has been seen on both the NCS and the UKCS in recent years.

The NPD's conclusions on project experience coincide with conditions identified by the OGA. To succeed, it is important that projects are sufficiently well matured to a good level of quality before being sanctioned. Feed must be completed before detail design starts, and the latter stage before construction begins. The OGA highlights the significance of building a competent project organisation with continuity of personnel throughout. Suppliers should be involved at an early stage, and a good collaboration should be developed with them.

7 Future developments on the NCS

On the basis of the discovery portfolio and projects being planned on producing fields, this chapter looks at what kinds of developments might be seen in the years to come. This will change in line with ongoing project maturation, exploration activity, oil price trends and technology advances, but nevertheless gives a picture of what types of projects and associated challenges and opportunities are in prospect on the NCS.

Experience described in this report and the NPD's 2013 study will also be relevant for future projects. It is important that licensees make active use of this and other experience in the work of pursuing developments on the NCS.

7.1 Discoveries

At 31 December 2018, the licensees of 85 discoveries on the NCS had yet to submit a PDO /4/. Resources in this portfolio break down into 360 million scm of liquids (oil, natural gas liquids and condensate) and 300 billion scm of gas. The total investment required to develop all the discoveries is estimated at NOK 400 billion in 2018 value.

The number of discoveries in the portfolio at the end of 2018 was about the same as in 1999. However, their average size had declined from 20.8 to 7.8 million scm in recoverable oe over the same period. The biggest discoveries have been developed, while new ones are largely smaller than before.

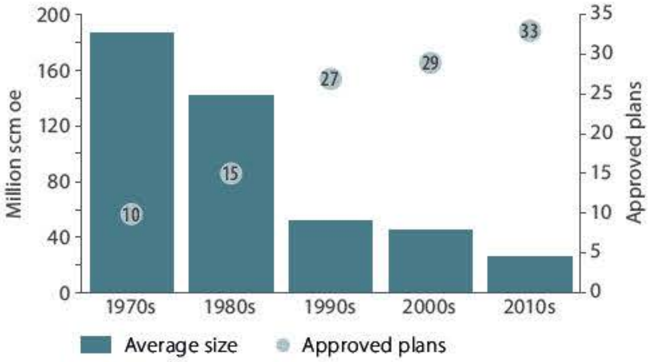

Figure 16 Average size at first PDO and number of approved development plans /4/.

Phasing in to existing or future infrastructure makes it possible to exploit discoveries which are too small to be profitable as stand-alone developments. Under current plans, some 80 discoveries with about 500 million scm in recoverable oe could be developed in this way. See figure 17, which shows discoveries and resources in the portfolio by their most likely development concept.

Subsea facilities are relevant for a large majority of the discoveries, followed by wells drilled from existing facilities and wellhead platforms. Fixed facilities are being assessed in the North Sea for the area between Alvheim and Oseberg, and a floater in the Barents Sea on Wisting.

Experience from the NCS in 2007-18 is that subsea projects have almost always been implemented in accordance with the approved plans, regardless of the operator's development experience.

About 75 per cent of the discoveries being considered for a tie-back have the same operator as the intended host facility. That will make it easier to understand the scope of work related to modification work on the latter, and provide greater incentives for the licensee group to come up with good solutions. This will also be positive in terms of coordinating the development with other activities on the facility. Collaboration between the players to find good solutions is also important where different operators are involved. In such circumstances, dialogue and information flow between the two must be good. Technical assessments which form the basis for the execution phase should not be influenced by undeclared commercial considerations.

The review of reserve developments shows that, in many cases, the size of small fields has declined from the PDO estimate. This makes it important that the licensees have a good grasp of the resource base in order to reduce uncertainty. Flexibility in the development concept to deal with the uncertainty could have great value if the downside for resources materialises. A spare well slot on a subsea template, for example, could provide flexibility at a relatively low additional cost. Appraisal and data acquisition when drilling production wells – such as pilots – will also be important.

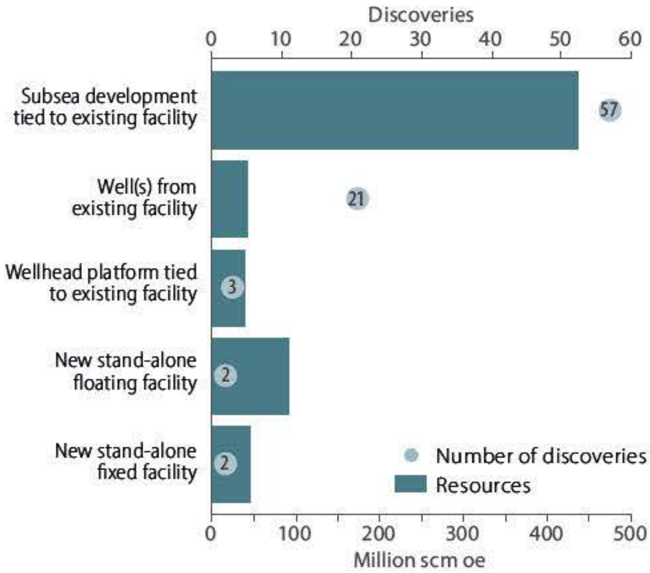

Figure 17 Discoveries and resources in the discovery portfolio by most likely development concept.

7.2 Fields

To maintain value creation on fields in operation, it is important that the licensees assess measures for improving the recovery of socio-economically profitable resources. Fields contain 85 per cent of remaining discovered petroleum resources on the NCS.

The companies reported about 150 specific projects for improving oil and gas production (resource classes 4 and 5) in 2018. In addition come possible but non-specific improved recovery measures (RC 7). A number of the projects on producing fields could involve the need to submit a PDO, as with many of the developments discussed earlier in this report. However, a lot will not require a PDO.

An overview of various types of specific but not sanctioned projects is presented in figure 18. Reported projects are dominated by new wells. Others which make a substantial contribution are further developments – particularly subsea projects – as well as improved recovery through low pressure production.

PDOs have been approved since 2013 for reopening two fields – Yme and Tor II (2019). At present, 10 projects reported to the NPD aim to recover additional resources from six abandoned fields.

Virtually all fields on the NCS produce for considerably longer than forecast in the PDO. Lower operating costs, improved recovery measures and a bigger resource base than expected extend producing life. Phasing into existing infrastructure is not only a precondition for developing today's discovery portfolio but also an important contribution to extending the producing life of existing fields. Maintaining good control of the condition of facilities and carrying out necessary maintenance and upgrades are important for safeguarding own production and regularity, and when planning tie-in projects with associated modifications to the facility. A number of parallel activities are often under way on a field, limiting available berths. The licensees will aim to assign work which requires a production shutdown to planned maintenance turnarounds. Good knowledge of a facility's condition, updated drawings and good maintenance planning therefore represent important contributions to establishing a best-estimate decision base for modification projects.

A number of projects in recent years have assessed reuse rather than newbuilding. Njord Future involves upgrades and modifications to the Njord A production facility and the Njord B storage ship. Converting a tanker for storage instead of building a new vessel was chosen for both Gina Krog and Martin Linge. Experience from these projects is that modifications are demanding and pose the risk of surprises along the way.

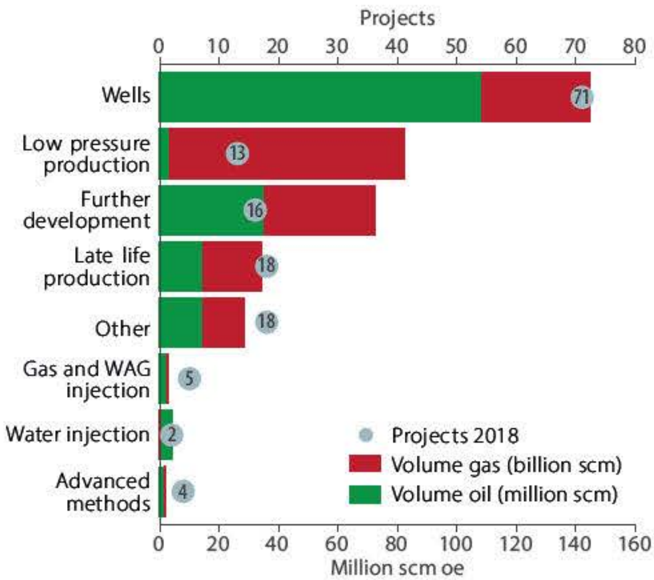

Figure 18 Projects and estimated recoverable oil and gas volumes by project category.

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Overview of projects

Large Norwegian companies (Equinor)	Alve, Gjøa, Vega and Vega South, Rutil Rimfaks Valley, Morvin, Troll B gas injection, Troll P-12, Yttergryta, Åsgard subsea compression, Visund South, Oseberg Delta 2, Valemon, Gudrun, Svalin, Aasta Hansteen, Gina Krog, Stjerne, Skuld, Vigdis North-East, Hyme, Johan Sverdrup phase 1, Oseberg west flank 2, Bauge, Byrding, Njord Future, Trestakk, Utgard, Johan Castberg, Snorre Expansion Project (SEP), Troll phase 3
Small companies	
Medium-sized companies	Lundin (Brynhild, Edvard Grieg), Marathon (Bøyla, Volund), DEA (Dvalin), Maersk (Flyndre), Wintershall (Maria, Nova), Talisman (Rev, Varg gas export, Yme), Repsol (Yme New Development), Aker BP (Ærfugl, Skogul, Valhall flank west), Det Norske (Ivar Aasen, Jette), BG (Gaupe, Knarr)
Majors	BP (Skarv, Valhall Redevelopment), ENI (Goliat, Marulk), Total (Atla, Martin Linge), ConocoPhillips (Ekofisk 2/4 VC, Ekofisk South, Eldfisk II)
European gas/power companies	VNG (Fenja), Centrica (Oda), Dong (Oselvar, Trym)
Others	Edvard Grieg oil pipeline (EGOP): Lundin as operator for Edvard Grieg conducted conceptual studies and evaluations for oil transport in the concept phase. Statoil took over as operator with the establishment of the EGOP joint venture in 2012 and pursued the chosen concept to the PIO. It was responsible for development. Utsira High gas pipeline (UHGS): As with the EGOP, Lundin was responsible for the concept phase and Statoil took over as operator for further planning and development on behalf of the licensees in the UHGS joint venture. Polarled: Equinor was responsible for the pipeline and Shell for upgrading at Nyhamna. Kårstø expansion project (KEP2010): Gassco is operator for the Kårstø plant on behalf of the Gassled joint venture. Equinor is responsible for technical operation of the plant, and thereby handled project planning and execution.

Table 2 Operators* and developments

* In those cases where operator/company type have changed during the execution phase, the table shows the operator who submitted the PDO. Martin Linge thus stands under Total, even though the latter's interest and the operatorship were acquired by Equinor some way into the execution phase.

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