MAIN REPORT

Study of field development projects on the Norwegian continental shelf

English translation of the report

«Utredning av feltutbygningsprosjekter på norsk sokkel»

Revision and approval overview of the Norwegian original

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Overview of figures

Abbreviations

AaH	-	Aasta Hansteen
AIV	-	Acoustic induced vibrations
Alarp	-	As low as reasonably practicable
API	-	American Petroleum Institute
ASD	-	Ministry of Labour and Social Affairs
ATM	-	Worker participation
BAT	-	Best available technology
bbl	-	Barrel
b/d	-	Barrels per day
BOP	-	Blowout preventer
CB&I	-	Chicago Bridge & Iron Company
D&W	-	Drilling and well
DG1	-	Decision gate one – concretise
DG2	-	Decision gate two – continue
DG3	-	Decision gate three – implement
DG4	-	Decision gate four – production
DNV	-	Det Norske Veritas
DP	-	Dynamic positioning
EICT	-	Electrification, instrumentation/control and telecommunication
EPC	-	Engineering, procurement and construction
EPCI	-	Engineering, procurement, construction and installation
Ex area	-	Hazardous areas with a potential for explosions
FAR	-	Fatal accident rate
Feed	-	Front end engineering design
FPSO	-	Floating production storage and offloading
FSU	-	Floating storage unit
GOR	-	Gas-oil ratio
Hazid -	-	Hazard identification
HC	-	Hydrocarbon
HHI	-	Hyundai Heavy Industries
HSE	-	Health, safety and the environment
HVAC	-	Heat, ventilation and air conditioning
IEC	-	International Electrotechnical Commission
IECT	-	Information, Electronics and Communication Technology
IMCA	-	International Marine Contractors Association
IMO	-	International Maritime Organisation
IMR	-	Inspection, maintenance and repair
ISO	-	International Organisation for Standardisation
ISS	-	Insulation, scaffolding and surface treatment
ITT	-	Invitation to tender

JOA	-	Joint operating agreement
KLD	-	Ministry of Climate and the Environment
KPI	-	Key performance indicator
LAS	-	Liquid additive system
MC	-	Management committee
MPE	-	Ministry of Petroleum and Energy
NCS	-	Norwegian continental shelf
NEA	-	Norwegian Environment Agency
NFD	-	Ministry of Trade, Industry and Fisheries
NGL	-	Natural gas liquids
Norsok	-	Competitive position of the NCS
NPD	-	Norwegian Petroleum Directorate
NVE	-	Norwegian Water Resources and Energy Directorate
oe	-	Oil equivalent
PDO	-	Plan for development and operation
Petec	-	Petroleum technology
PIO	-	Plan for installation and operation
pdQ	-	Production, drilling and quarters platform with facilities for partial processing, drilling area without rig and quarters
PdQ	-	Production, drilling and quarters platform with facilities for processing, drilling area without rig and quarters
PDQ	-	Production, drilling and quarters platform with full facilities
PL	-	Production licence
Plem	-	Pipeline end manifold
PSA	-	Petroleum Safety Authority Norway
QA	-	Quality assurance
QC	-	Quality control
RBI	-	Risk based inspection
RNB	-	Revised national budget
Sage	-	Scottish Area Gas Evacuation System
SAR	-	Search and rescue
scm	-	Standard cubic metre
SCR	-	Steel catenary riser
SD	-	Ministry of Transport
SMOE	-	Sembcorp Marine
SSIV	-	Subsea safety isolation valve
Surf	-	Subsea umbilicals, risers and flowlines
TLP	-	Tension-leg platform
Trace	-	True advanced collaboration environment
UCCI	-	Upstream capital cost index
VOC	-	Volatile organic compound

1 Background and methodology

1.1 Background for the study

Certain field developments on the NCS have faced major challenges from costs and delays over the past decade, with associated examples of quality and HSE problems – particularly in the start-up and production phases. Goliat is a case in point. The challenges in this project have attracted a great deal of attention from both the general public and the government. The White Paper on HSE in the petroleum sector (Report no 12 to the Storting, page 65) published in the spring of 2018 addresses this as follows:

> Most developments on the NCS are implemented within the uncertainty range for time and costs specified in the PDO. However, certain developments have faced challenges with substantial overruns for both costs and execution time. This may also be significant for quality and HSE in engineering and construction.

The purpose of this study is to identify possible deficiencies in project execution and to propose both measures and learning points for improving company implementation methodology and for regulatory supervision. The PSA has therefore decided to commission a study of three field developments on the NCS in order to identify learning points relevant for HSE. This work is to identify challenges, underlying causes and recommendations for improvement measures in all phases of a field development.

Appendix A concerning earlier project reviews on the NCS summarises the main findings from similar studies conducted earlier as a reference for the findings made here.

1.2 Object of and scope of work for the study

Goliat and two other field developments will be reviewed in order to contribute to learning lessons and building expertise in government and the industry. Both challenges and positive experiences will be identified. The study will cover all project phases from the award of the production licence, through exploration phases, feasibility studies, the concept phase, preparation and approval of the PDO, design, construction, completion and start-up, and over at least the first year on stream.

For each of the production licences, the study will cover the operator company, the licensees and the government's role. The following will be included for the various phases in the actual study.

Follow-up by the companies, including:

- the quality of the decision base for the various phases
- involvement of and collaboration with the workers
- involvement by government
- qualification, utilisation and follow-up of suppliers/contractors
- organisation of the work
- the company's own follow-up
- follow-up by the licensees.

Follow-up by the government, including:

- permits, approvals and consents
- supervision and the use of enforcement powers.

1.3 Selection of projects

According to the PSA's specification for the study, it will cover three field developments on the NCS. One has to be Goliat, the other two must be projects with a PDO approved in 2010-15. Since the study is to cover the start-up and production phase, eight developments were identified which satisfied the selection criteria. The relevant projects were Gudrun, Valemon, Gina Krogh, Aasta Hansteen, Martin Linge, Knarr, Edvard Grieg and Ivar Aasen. Evaluation was based on documentation made available by the PSA.

The criteria applied fall into two groups. Assumptions utilised describe important characteristics for the project, while the measurable end result is a quantification of the final outcome.

Assumptions:

- the project’s organisation and size
- operator experience/governing documentation
- partnership composition
- robustness of the concept
- extent of new solutions/technology
- operator’s NCS expertise
- maturity at DG3/later changes
- execution strategy and choice of contractors
- quality of contractor follow-up/risk management
- HSE during project execution.

Measurable end result:

- number of serious incidents/investigations (PSA database)
- delays
- cost overruns
- quality of the facilities (production achieved in first year on stream).

Parameters qualifying for a green, yellow or red traffic light in the evaluation are defined for each of these criteria. See Figure 1-1.

Criteria definition

Criteria	Green	Yellow	Red
Project organisation and size	Capex < 15 GNOK	Capex : 15 – 30 GNOK	Capex > 30 GNOK
Operator experience/ management system	Established as an international operator	Established operator on other types of projects or insufficient management system	First time operator for a large project or inadequate management system
Partnership	No of owners: 3 to 6	No of owners <3 or > 6	< 3 owners with major difference in priority
Conceptual robustness	Break even (BE) < 50 USD/boe	BE between 50 og 70 USD/boe	BE > 70 USD/boe
New technical solutions/ new technology	Limited amount of new technology	Value of “new” solutions > 5 GNOK capex or new technology not fully qualified at DG3	Value of “new solutions» >10 GNOK capex, or new technology with increased cost in execution
The operators NCS competence	Established NCS operator	No former NCS operatorship	No former NCS operatorship, limited use of Norwegian experience/ personnel and standards
Technical maturing at DG3/ late scope changes	In accordance with management system and given requirements	Not in fully accordance with management system and given requirements	Needed more than a year to clarify scope and formal requirements after DG3
Execution strategy and selection of contractors	Experienced contractor related to scope and contract format	U-optimalt valg av strategi basert på operatørens kompetanse og markedets pris og tilgjengelighet	Gjennomføringsfasen ga store tids og kostnads overskridelser (+25% for tid og/ eller kost)
Quality of contractual follow up/ risk management	< ½ year before important risks were identified	> 1 year before important risks were identified	Insufficient risk management
HSE in execution	No fatalities during execution	No fatalities but other serious incidences	One or more fatalities during execution
Measured results:			
Incidences reported to and investigated by PSA	No serious incidents, no investigations	1 – 3 serious incidents, no investigations	> 3 serious incidents or one or more investigations
Schedule delays	< ½ year delay (DG4)	½ year - 1 years delay (DG4)	> 1 years delay (DG4)s
Cost overruns	< 10 %	10 – 25 %	> 25 %
Quality of production facilities	< 15 % deviation from PDO year 1	15 – 30% deviation year 1	> 30% deviation year 1

Figure 1-1. Selection criteria.

Four of these projects have been executed with Equinor as the operator, while the four others were implemented by other operators. Selecting three different operators is desirable in order to ensure the broadest possible basis for comparison in the study.

1. Among Equinor’s projects, Aasta Hansteen stands out as the one which most resembles Goliat in size, concept, geographical location, contract strategy and choice of contractors. This development has had a delayed start in relation to its PDO.

2. Where the other projects are concerned, Martin Linge was dropped because of the lack of start-up and production data within the time frame specified for the study.
3. Of the three remaining projects, Ivar Aasen has an execution strategy which most resembles Goliat and Aasta Hansteen. At the same time, it shows a "green light" for all the result parameters, including HSE.

Based on the specified criteria, the following three projects were selected:

- Goliat – operated by Eni (now Vår Energi)
- Aasta Hansteen – operated by Statoil (now Equinor)
- Ivar Aasen – operated by Det Norske (now Aker BP) .

All three operators have changed their name once or more during the period. This study largely utilises their original designation when past incidents are described, and preferably their present name in the summary and recommendations for the future.

A selection from the measurement of results (Figure 1-1) is summarised in Figure 1-2.

Criteria	**Ivar Aasen**	**Aasta Hansteen**	**Goliat**
HSE in project execution			
HSE in operations			
Schedule delays			
Cost overruns			
Quality at production start		4Q 18	

Figure 1-2. Measurement of results. (Source: Acona)

Given the intention of the study, which is to review experiences from projects and processes which have been shown to present HSE challenges and to identify lessons from projects with a positive outcome, Aasta Hansteen (Equinor) and Ivar Aasen (Aker BP) were chosen as the two developments to be studied in addition to Goliat. See *Utredning om feltutbygginger på norsk sokkel – valg av to tilleggsprosjekter* (24 October 2018).

1.4 Focus areas

The starting point for the study is the PSA's definition of HSE "...embraces safety, the working environment, health, the natural environment and material assets (including production and transport regularity)". See section 1 of the framework regulations with comments and Figure 1-3. Learning points with relevance for HSE are to be described.

1. Health
   - The Working Environment Act is respected and complied with.
   - Workers' rights and participation are taken care of.
   - Requirements on noise, ergonomic stress, chemical handling and so forth on the facilities are understood and complied with.
   - The workload is acceptable.

2. Environment
   - Regulations governing discharges/emissions to the natural environment are understood and complied with.

3. Safety
   - Requirements for the identified technical solutions comply with Norwegian requirements and regulations.
   - Major accident risk – identification and use in managing the project.
   - The facilities are engineered and built to the specified requirements.
   - Work in the development phase (onshore and offshore) is executed in accordance with best practice.
   - Production preparations and work procedures comply with best practice on the NCS.
   - Established working procedures are respected and complied with.

Figure 1-3 provides an overview of important factors in the project's execution phase which influence and are significant for HSE results and value creation in the overall project.

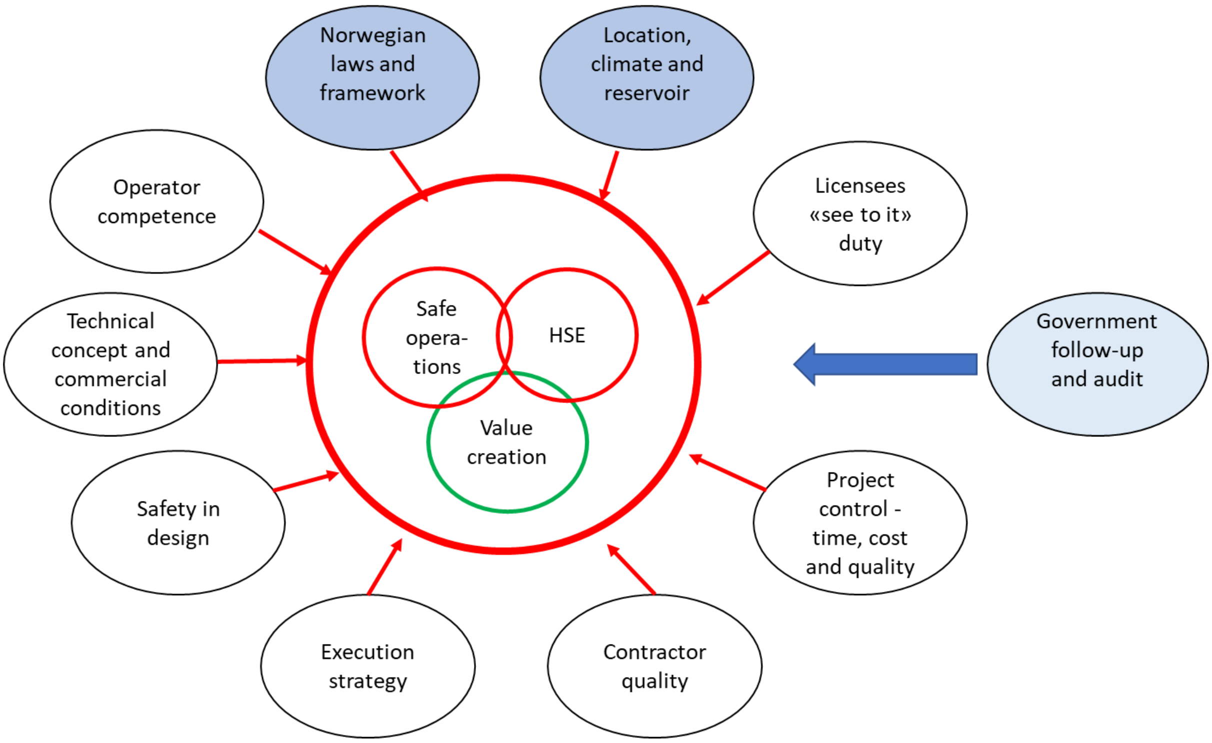


Figure 1-3. Influences on the HSE results. (Source: Acona)

1.5 Methodology

Each of the projects has been reviewed in the following stages:

- review of documents received from the regulators involved (PSA and NPD)
- review of documents based on access to all relevant documentation from the operators
- interviews with key personnel from the three projects and relevant government agencies
- analyses conducted and working hypotheses developed for each field
- more in-depth investigation of available documentation based on these hypotheses
- a new round of interviews with representatives from the operator's management and the partner companies.

This material has thereafter been used to compare the three projects. The purpose has been to identify learning points related to both good and less good practice.

- Comparison between the three projects.
- Learning points with proposals for future improvement.
- Final report with associated presentational materials.

1.6 Execution

The PSA is the client for the study. A tendering process was conducted in the third quarter of 2018. This assignment was awarded to Acona in September 2018. The project team has comprised:

- Helge Hatlestad (leader) – discipline: management in the early phase, development and production
- Jonas Odland – discipline: platforms and marine operations
- Hans Jørgen Lindland – discipline: subsea installations, drilling and well
- Hilde Oddaker – discipline: HSE/technical safety
- Ernst Abrahamsen – discipline: project management, execution and project control
- Martin Tveiterå (admin support) – discipline: risk

The project team has been followed up closely by the PSA through monthly and working meetings.

2 Parameters for the three selected projects

This chapter identifies elements in the operating parameters which characterise the three selected projects compared with other developments executed since 2000.

2.1 Location and natural conditions

Ivar Aasen lies in a North Sea area which is well known and where a developed infrastructure exists for oil, gas and supply services. The water depth is only 113 metres, permitting the use of conventional fixed platforms with wells conducted to the topsides level. Drilling can be performed by a jack-up rig.

Goliat lies in the Barents Sea, not far from Snøhvit. It was the first oil field discovered in the area, and infrastructure is lacking for both oil and gas exports. The water depth is about 350 metres, similar to northern parts of the North Sea and the Halten Bank. Waves, winds and currents are no worse than in areas of the North Sea, but Polar lows can occur. Low temperatures with possible snow and ice can occur, and light conditions are poor in winter.

Aasta Hansteen lies in the Norwegian Sea area known as the Vøring Plateau. The water depth is about 1 300 metres, and the combination of waves, winds and currents is among the most challenging on the NCS. It is a considerable distance from land and the area lacks infrastructure. Development depended on establishing a new infrastructure for gas, which involved laying the new Polarled gas pipeline to Nyhamna on the Møre coast.

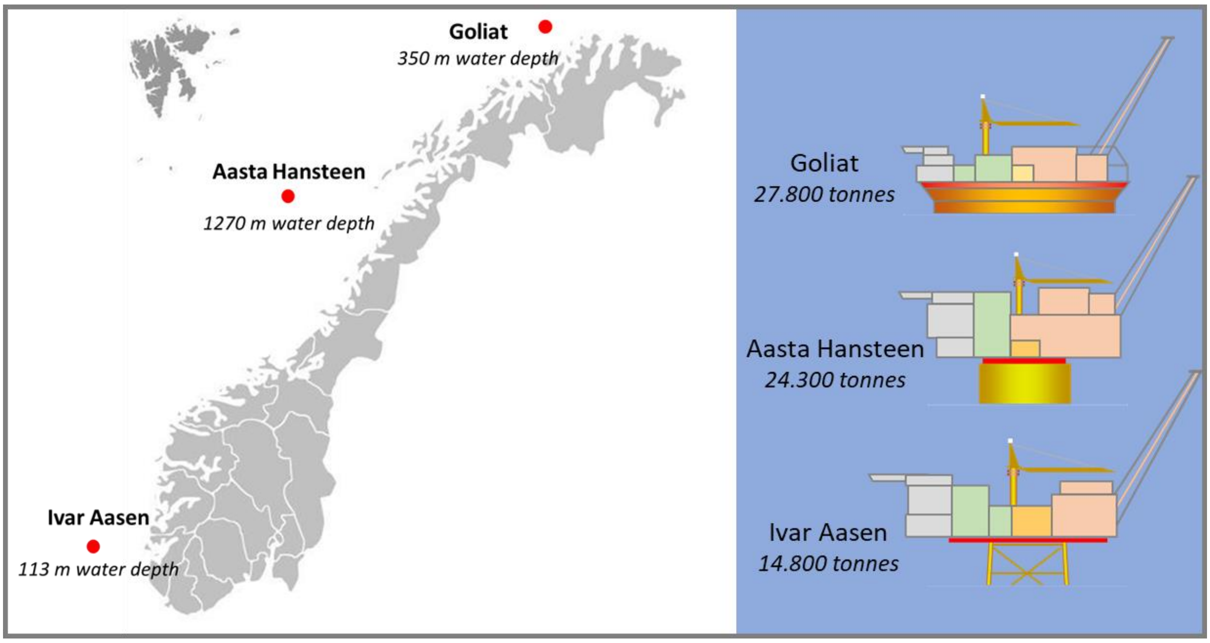


Figure 2-1. Location of the three selected projects. (Source: Acona)

2.2 Reserves base and sales products

The reserves base for the three fields is shown in Figure 2-1, measured in scm oe. Compared with other fields on the NCS, they are to be regarded as small to medium-sized. HCs in the reservoirs are a blend of lighter and heavier components which are separated into various sales products, depending on the available infrastructure. Most fields deliver a liquid product (oil or condensate) and a gaseous product which can be split into sales gas and NGLs at a land terminal

Ivar Aasen lies in an area where both oil and gas can be sold through existing infrastructure. This means that both oil and gas create value.

Goliat is an oil field where the crude is exported by offshore loading directly from an integrated store into tankers. No opportunity currently exists for marketing the associated gas separated from the oil. It is therefore injected back into the reservoir and helps to maintain its pressure. The gas could be recovered again and sold at a later date. In other words, the Goliat platform is equipped with gas treatment and compression without these providing direct income.

Aasta Hansteen is a gas field with a small proportion of condensate. Investment in a new pipeline to Nyhamna and expansion of the terminal there were needed to exploit the gas. To handle the marginal condensate flow, the platform incorporates expensive and complicating storage for this product with a system for loading it directly to tankers.

In general, it can be said that gas facilities require a quantity of heavy equipment for gas processing and compression. Oil platforms also have to handle a certain amount of associated gas, even if it is only injected back in some cases, must usually treat large quantities of produced water as well, and need special systems for water injection.

Figure 2-2a shows how reserves in the three fields compared with other Norwegian developments since 2000 which feature stand-alone platforms.

Figure 2-2b shows breakeven prices for the same fields. These are high for the three projects covered in this study. That reflects technical conditions as outlined above, as well as the fact that the development decision was taken at a time when the level of activity in the industry was very high and costs were generally high.

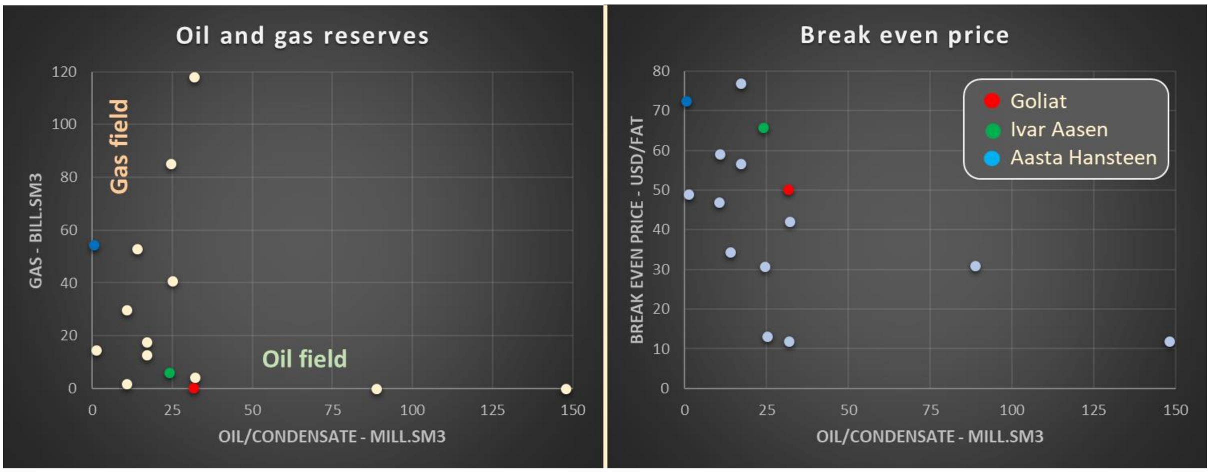


Figure 2-2. Oil and gas resources in Norwegian fields developed since 2000. (Source: Acona, based on White Papers from the MPE related to PDOs)

2.3 Oil price and cost trends in 2000-20

Projects are developed and matured through a series of decisions up to the final investment commitment, which is confirmed with the approval of the PDO. The project’s value creation potential is expressed as expected net present value.

Calculating expected present value is based on expectations of future market prices for oil and gas. Since great uncertainty prevails about price assumptions, emphasis is given to assessing the project’s robustness to low oil prices.

The breakeven price illustrates how robust a project is to lower market prices. It represents the average future oil price which a petroleum field must receive to cover all future costs while providing a specified return on the capital. Breakeven prices are calculated both before and after tax. Another term for the breakeven price before tax is the technical unit cost. This shows that the breakeven price can also be regarded as a weighted sum of all future costs divided by the saleable volume of oil and/or gas.

For a project to be profitable and provide acceptable robustness, a certain differential must exist between the expected market price and the calculated breakeven price. During periods when pessimism and a belief in low oil prices prevail, a pressure to reduce costs will weigh on all project decisions, particularly for marginal developments. When optimism and faith in high oil prices dominate, it will be easier to base decisions on robust cost estimates.

Figure 2-3 and Figure 2-4 show how the projects are placed along the time axis and how the level of costs has changed over time.

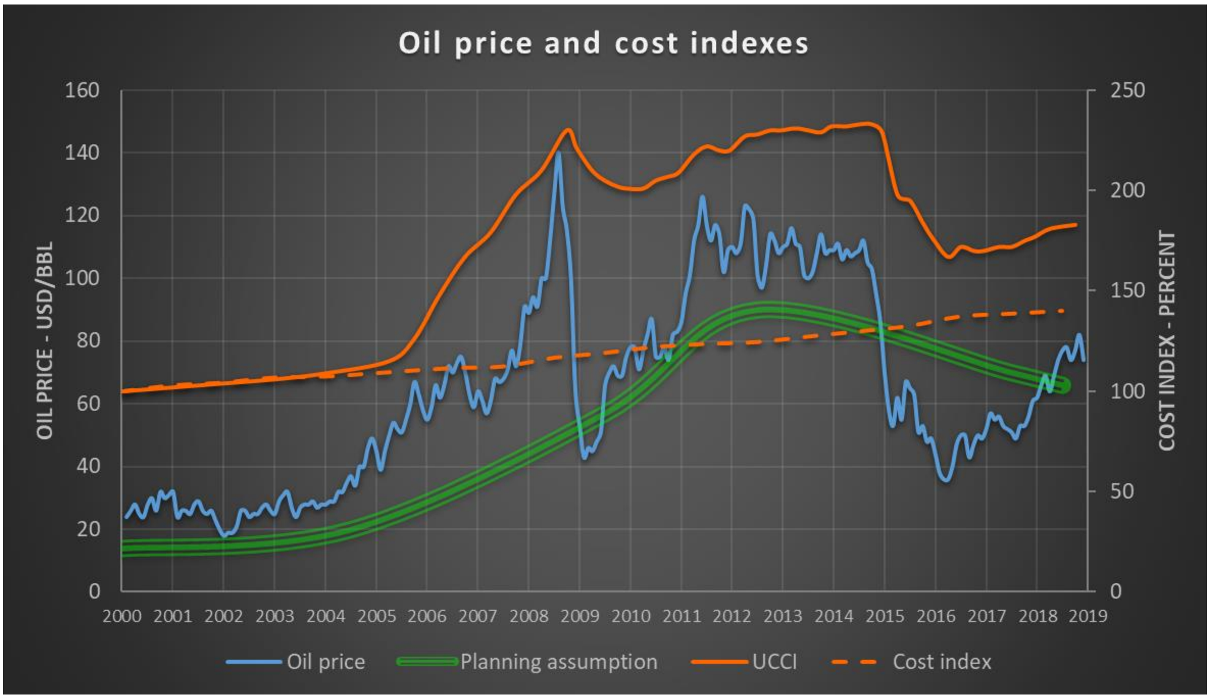


Figure 2-3. Oil price, planning assumption, general cost index and UCCI. (Source: Acona)

History shows that oil prices fluctuate greatly, both in the short term and over rather longer periods. This may reflect imbalances in the market, generally created by global incidents, international crises, financial crises and so forth. Forecasts for future oil prices are based on observations of the present level, trends and analyses. The various oil companies have their forecasts and planning assumptions, and each licence partnership selects which of these will form the basis for illustrating the profitability of the project before a project decision is made.

Immediately after 2000, an oil price of USD 14/bbl was assumed. Expectations of future prices increased in line with the rise in market prices, and an oil price of USD 90/bbl was assumed for a time around 2013. Following the big oil price slump after 2014, expectations were again reduced.

Figure 2-3 illustrates these conditions. The oil price shown is the market average for Brent Blend. The planning assumption is the oil price used by the industry in financial analyses, and varies from company to company. Its curve is intended to represent a typical level. The UCCI is an international cost index for offshore projects, while the dotted line is a general cost index (inflation factor). The dramatic slump in oil prices during the last half of 2008 was caused by the financial crisis.

Historically, the level of costs in the offshore industry has varied in line with the expected oil price. This means that the breakeven price also varies over time and reflects expectations for the market price. The breakeven price generally falls within a range of 50 to 90 per cent of the expected market price.

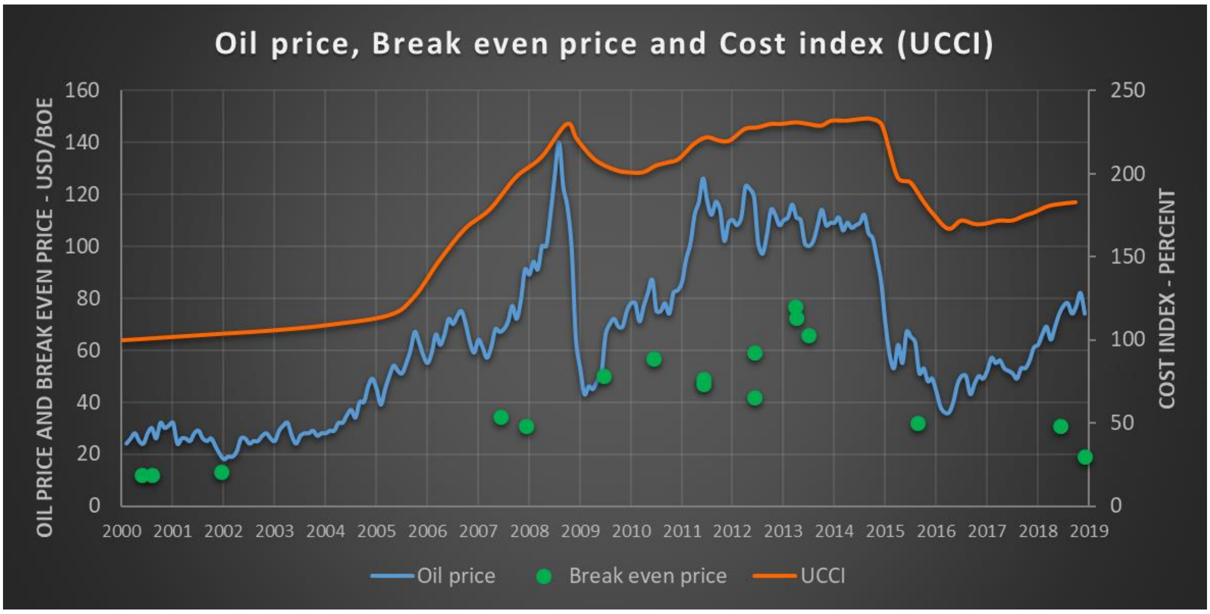


Figure 2-4. Oil price, breakeven price and the offshore cost index (UCCI). (Source: Acona)

Figure 2-4 presents the oil price and UCCI in the same way as in Figure 2-3, plus breakeven prices for 16 Norwegian platform-based developments at the time of PDO approval.

2.4 Division of roles between operator, licensees and government

The main goal of Norwegian petroleum policy is to facilitate profitable production of oil and gas in a long-term perspective. Value created will fall as far as possible to Norwegian society, administration will conducted within acceptable parameters for HSE, and account will be taken of protecting the natural environment and coexistence with other industries.

Norwegian petroleum operations are regulated by the licensing system pursuant to the Petroleum Act. Exploration or production licences are awarded by the MPE on behalf of the government. Production licences are allocated through regular licensing rounds and annual awards. The companies must have a grasp of geology, technical expertise, financial strength and expertise with HSE.

Chapter 4 of Proposition no 114 (2014-2015) to the Storting on the Johan Sverdrup PDO describes the Norwegian administrative model. A corresponding account was provided by the petroleum and energy minister in response to the Auditor General's investigation of government work to improve oil recovery from mature areas of the NCS (Auditor General document 3:6 of 2014-15).

2.4.1 Licensees and operator

All companies wishing to pursue petroleum operations on the NCS must be qualified as licensees or operators. They must demonstrate that they can contribute to increased value creation and have HSE expertise which helps to strengthen safety. New players are assessed by the PSA and the NPD on behalf of their parent ministries.

Licensee. A licensee is a company with a production licence awarded pursuant to the Petroleum Act. Generally, a licence will be held by several licensees, but only one of these is appointed as the operator. All licensees undertake to contribute actively to the licence, in part by checking that the operator has activities under good control.

Operator. The operator is the company in charge of day-to-day management of activities in the licence on behalf of all the licensees. It has overall responsibility for ensuring that activities are conducted prudently and in accordance with the regulations. The operator must see to it that everyone doing work for it complies with the requirements in the HSE regulations.

"See to it" duty. The "see to it" duty is a general, overall obligation additional to the company's duty to comply with the regulations. It derives from the Petroleum Act, and the operator's management system must describe how it will be discharged.

The see to it duty also applies to the other licensees, who must make provision for the operator to execute its functions and see to it that the operator performs these in accordance with the regulatory requirements. A licensee is responsible for taking action if it identifies conditions which do not accord with the regulations.

2.4.2 Government

The MPE's main job is to facilitate a coordinated and integrated energy policy. An overarching goal is to secure high value creation through efficient and environment-friendly administration of energy resources. Energy policy must be constructed to ensure the best possible utilisation, within environmentally prudent parameters, of the overall labour, knowledge, capital and natural resources available. As the secretariat for the political leadership, the ministry's goals will develop in line with the government's energy policy goals, as expressed in part through relevant White Papers and Propositions (Bills) to the Storting (parliament).

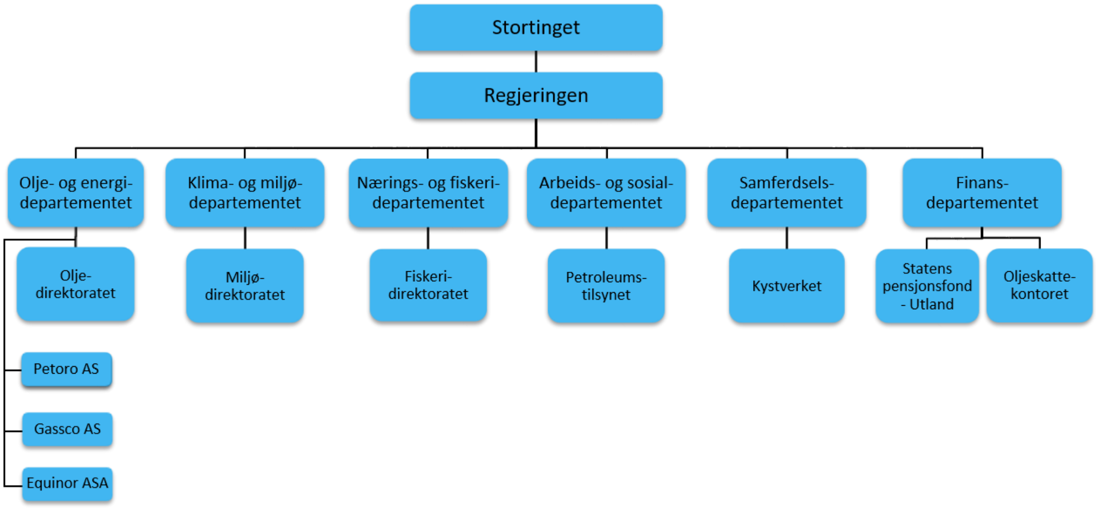


Figure 2-5. Overview of relevant government bodies. (Source: MPE)

The MPE coordinates the consideration of licence awards, PDOs and PIOs. This is done in cooperation with the ASD, the NPD, the PSA and the NEA. While the MPE/NPD are responsible for resource management and socio-economic aspects, the ASD/PSA handle HSE and the NEA is responsible for the natural environment, emission/discharge permits and oil spill preparedness. An overview of the government bodies involved is presented in Figure 2-5. See otherwise Norskpetroleum.no/en for further details.

Gassco is involved where the plans concern gas processing and transport. The same applies to the NVE in cases covered by the Norwegian Energy Act. In plans where the licensees are considering a connection to the electricity generating system on land, the NVE, Statnett SF and local grid companies have a role relating to the power system. The KLD, the NFD and the SD, together with their subordinate agencies and directorates, are consultative bodies for impact assessments.

The PSA monitors Norwegian development projects through every project stage – from the early evaluation phases, through concept development and definition, design, construction, commissioning and operation, to cessation. This monitoring takes various forms during the course of a project.

Activity plans, including a supervision plan, are established by the PSA for developments. Such plans are based in part on observations of and knowledge about conditions in and around a partnership, the operator, special circumstances with a project and so forth. The supervision plans can be adjusted along the way if a project encounters special challenges related to HSE.

The PSA will check that requirements for HSE are met from the choice of concept stage, through project development and on into the production phase. Furthermore, it will give consent to start-up/initiate defined operations. The government has a responsibility to ensure that an integrated approach is taken to regulating the sector and that regulatory developments keep pace with general trends in the industry. In addition, the PSA is responsible for assessing if the standards referenced in the regulations are good enough.

A key role in administering Norway's oil and gas resources is played by the NPD. It serves as an active driver of the companies in order to realise as much as possible of the resource potential on the NCS and thereby create the greatest possible value for society. The NPD monitors that the companies emphasise long-term solutions, upside opportunities, the benefits of coordinated operations and economies of scale, and not losing resources. Emphasis is given to making sure that the NPD has sufficient capacity and expertise to check that relevant improved recovery measures are studied by the licensees and that decisions are based on a long-term perspective.

The government defines the various milestones in the project development process in the following way.

Decision to concretise – DG1: Milestone where the licensees have identified at least one technically and commercially feasible concept which provides the basis for launching studies leading to a choice of concept.

Decision to continue – DG2: Milestone where the licensees decide to continue studies of one concept, which leads to the decision to implement.

Decision to implement - DG3: Milestone where the licensees take the investment decision which results in the submission of a PDO or PIO.

An overview of the principles for government involvement is presented in Figure 2-6.

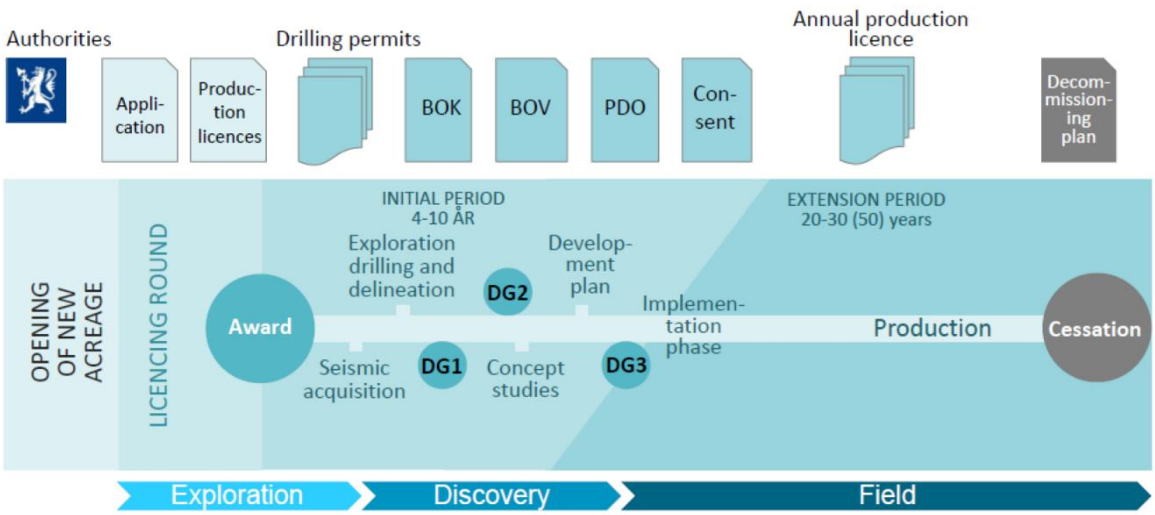


Figure 2-6. Overview of government involvement. (Source: NPD)

The division of responsibility in Norway's petroleum industry is clear: "The player who owns the risk also owns the responsibility for dealing with it. In other words, it is the licensees who are responsible for activities being conducted prudently and in accordance with the regulatory requirements."

It is neither possible nor desirable for the government to regulate the industry in detail. The PSA is responsible for setting HSE parameters for operations, and for following up that these are conducted prudently. This responsibility includes developing the regulations, supervising that the companies comply with the requirements and exercising its enforcement powers appropriately in the event of regulatory breaches.

2.4.3 Licensees' role and responsibilities

A licensee's responsibilities and duties derive from the Petroleum Act and associated regulations, and are also described in the licence documentation. The division of roles and responsibilities between the operator and the other licensees is described in the licence's joint operating agreement (JOA). The licensees establish an MC to which they all belong, with the operator's representative as chair. The voting rules are agreed at licence award. Each company is responsible for the safety of its own activities. This represents a basic principle in Norway's petroleum regulations.

The MC is the top decision-making body for the production licence, and must be in control of all operations related to this. It will also be responsible for strategies and goals, and for exercising control of the operator's activities.

Pursuant to section 10, subsection 2 of the Petroleum Act, the licensees must ensure that the activity can be carried out prudently, in accordance with applicable legislation, and in a manner which safeguards good resource management and HSE.

The established division of responsibilities and roles between government and licensees means that responsibility for commercial decisions concerning projects and fields on the NCS rests solely and entirely with the companies which conduct operations, take investment decisions and execute projects at their own expense and risk.

2.4.4 Operator's role

The operator conducts and administers the daily execution and management of all work related to the licence. These activities are executed and controlled in accordance with regulations adopted by the JOA. The operator is responsible for the safety of its own operations, because it possesses the necessary detailed knowledge, decision-making authority and – not least – resources to ensure that the requirements in the regulations are met and complied with. This means the operator is responsible for securing all necessary permits and consents and for entering into binding agreements and contracts on behalf of the licence. It has a duty to report to the management committee on all issues of significance for value creation and to operate safely in every phase from licence award to relinquishment.

Workers must participate
Worker participation is a regulatory requirement in Norway. The principle is that the person exposed to the risk must participate in decisions related to HSE. This is partly intended to ensure that the collective knowledge and experience of the workforce is utilised to ensure that issues have been adequately clarified before decisions are taken. Safety delegates and members of the working environment committees in the companies have a special role – and duty – in this respect. The companies must make provision for genuine worker participation, and ensure that legally prescribed bodies such as the working environment committee and the safety delegate service are used in a good and constructive manner.

Tripartite collaboration is a precondition
Tripartite collaboration between employers, employees and government has a long history in Norwegian industry. In the petroleum sector, this means that these parties sit down together to collaborate constructively on improvements – including to safety and the working environment. The Safety Forum and the Regulatory Forum are two of the most important arenas for such cooperation in the petroleum industry. Great agreement prevails about preserving the value represented by tripartite collaboration.

2.5 Management parameters for a project

Management parameters for projects are costs, execution time and quality. These can be more or less ambitious, but must basically be realistic. Risk factors exist in any project, and unforeseen incidents could create difficulties. Progress is monitored and assessed continuously, and corrective measures are applied for possible nonconformities. The right balancing of costs, time and quality represents a challenge for the project and an important part of its strategy. If the parameters are unrealistic, striking such a balance will be difficult and the project can get completely out of control. To restore that, the parameters may have to be adjusted.

Costs are an easily measurable parameter which directly affects the project's profitability and robustness to low oil prices.

Time, expressed by the date for starting production, is another easily measurable parameter which directly affects the income profile and thereby the project's profitability and robustness to low oil prices. In some cases, production start-up may be particularly important because of commercial commitments (such as gas deliveries).

Quality is not so readily measured in the execution phase, but a reduced level can have an effect during start-up and throughout the production phase in the form of increased safety risk, shutdowns and poor regularity, and thereby loss or postponement of output.

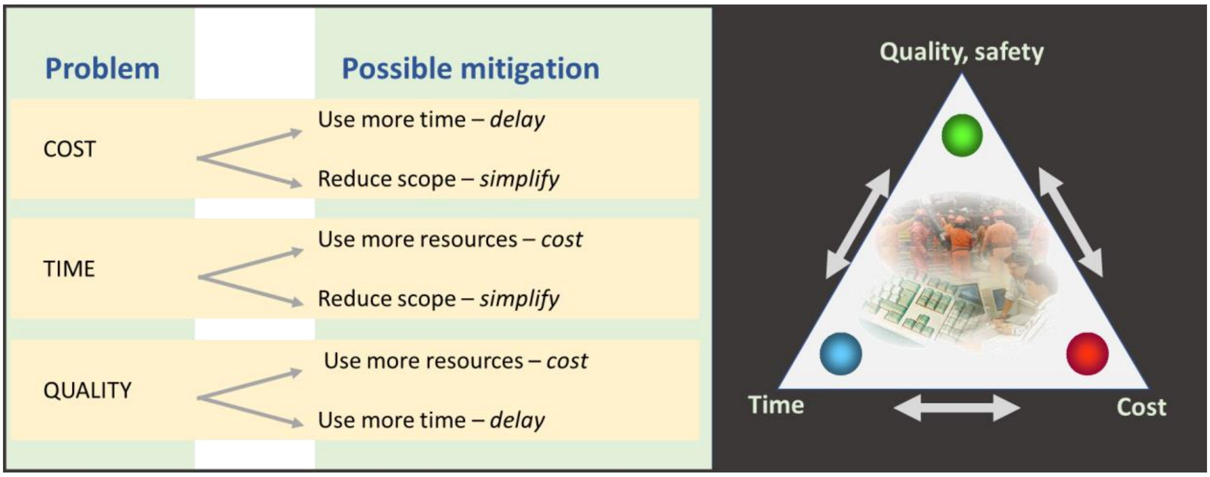


Figure 2-7. Balancing quality, time and costs. (Source: Acona)

Where projects get into difficulties, effective measures must be taken to ensure the best possible control over these three main parameters. The strategy could vary from one project to another but, depending on how great the pressure is, compromises may be necessary for at least one of the parameters. Some examples are provided below.

- Rising costs can be combated by allocating more time – the schedule is adjusted.
- Rising costs can be combated by reducing the scope of work, which can be regarded as a quality reduction. Simplification such as removing parallel equipment units, for example, could be relevant and acceptable, while measures which could increase the safety risk will not be considered acceptable.
- Delays can be combated by paying for additional resources (acceleration costs).
- Quality problems can be combated by allocating more time and/or accepting increased costs.

2.6 Norway's HSE regulations

The Norwegian HSE regulations primarily rest on performance-based requirements which specify the properties and qualities equipment should possess. How it should be designed to meet the regulatory requirements is up to the individual player. The performance-based HSE regulations mean that the players themselves must satisfy the requirements set by adopting specific requirements for methods and approaches which produce the required result. This freedom of choice is a distinctive feature of the Norwegian regulations and builds on an assumption that the players themselves are the ones who possess relevant expertise and who are best equipped to determine which approach yields the best result. The regulations lay the basis for utilising flexible and efficient solutions.

These performance-based regulations provide freedom, but also demand that the players actively interpret and supplement their provisions. Which solution should be chosen will depend on an interpretation of the level of safety sought by the regulatory requirement, which is often couched in general terms. A judgement must therefore be made of the quality of the various solutions and the risk associated with them, taking account of the intended utilisation and general cost-benefit considerations. This is a demanding exercise, and whether an intended solution meets the relevant regulatory requirements can easily be open to doubt.

To reduce this uncertainty, guidelines to the regulations have been drawn up. These contain more detailed descriptions of how the provisions are to be understood, and references to selected standards which provide a recommended way of meeting relevant regulatory requirements. The principle determining the relationship between statutes, regulations, guidelines and standards is presented in Figure 2-8. The guidelines are intended to provide the players with some assurance that they are applying an accurate understanding of the regulatory requirements, and will also ensure that the players adopt a virtually identical and adequate level of safety.

Neither the guidelines nor the standards they refer to are legally binding. Players are free to choose solutions other than those aimed at in the guidelines. This is a consequence of the systematic approach taken by the regulations and presupposed in section 24 of the framework regulations. This provision requires that a player using a solution other than the one recommended in the guidelines must be able to document that the chosen solution fulfils the regulatory requirements. This is “only” a procedural rule. In material terms, a different solution can be chosen as long as it can be demonstrated to fulfil the requirements in the regulations.

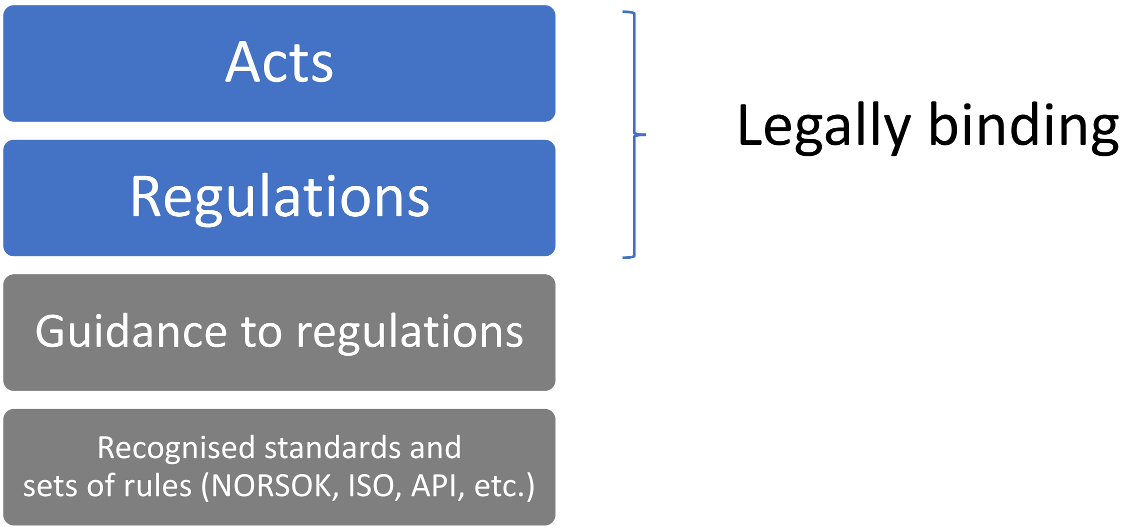


Figure 2-8. HSE regulations on the NCS. (Source: Menon publication 39/2016)

The standards referenced in the guidelines are not exclusively of Norwegian origin. On the contrary, a number of international standards and sets of regulations are referred to as indicative of the required safety level. These derive from the API, the ISO, DNV, the IEC, the IMO, Imca and the EN. Nor is it the case that the Norwegian standards are stricter than those in other norms. An international standard may well set stricter norms for safety and involve higher costs than Norsok or other Norwegian standards and sets of rules.

HSE requirements on the NCS are largely the same today as they were 15 years ago.

The PSA’s investigation reports show that inadequate design or faulty construction of equipment was found in every third incident investigated during 2006-15. Every fourth incident was caused by incorrect use of equipment. In many cases, the equipment has been used in direct conflict with the supplier’s user manual. The PSA has identified errors and inadequacies in safety-critical information on the facility in every fifth incident investigated.

Specification requirements determine how the manufacturer designs its equipment. Shaping these appropriately is therefore crucial for ensuring that the equipment is designed in a safe way and in accordance with its intended area of use.

2.7 Safety functions for a field development

Safety functions for a field development:

a. discover abnormal conditions
b. prevent abnormal conditions from developing into a hazard and accident
c. limit damage in the event of accidents.

The design philosophy and an overall system description are established early, while the details are developed through Feed and detailed engineering.

2.7.1 Risk reduction/barriers

Risk-reducing/barrier-secure and robust solutions are required which minimise the probability of incidents occurring. Where risk cannot be eliminated through a safe and robust design, barriers must be established which ensure that the necessary level of safety is attained. A barrier's function is to protect against faults, hazards and accidents which could arise. This function is implemented by barrier elements – in other words, technical, operational or organisational factors which individually or collectively identify conditions which could lead to faults, hazards or accidents, reduce the opportunity for specific faults or accidents occurring or developing, and limit or prevent harm.

The barrier concept is most frequently used in connection with incidents which have a major accident potential, but can in principle be generalised to other accidents where physical stresses could lead to loss of life or damage and health problems. However, attention in the rest of this section is concentrated on major accident prevention.

2.7.2 Leaks and ignition source control

Attention will be concentrated on avoiding leaks. Even with safe and robust solutions, however, some threat of leakage will exist. Other barriers must then ensure that the position is controlled in a safe way.

Separating ignition sources from fuel sources and living quarters from equipment which presents the greatest potential hazard represents an important principle. Ideally, fuel sources should be placed as far as possible from ignition sources so that leaks fail to ignite. In conventional land plants with no space restrictions, opportunities have generally be taken to do this. Achieving sufficient separation on its own is difficult with large multifunctional platforms. This must then be offset by introducing various types and levels of ignition source control.

In a project development phase, attention where such control is concerned will be concentrated on ensuring that possible ignition sources are positioned in a way which minimises the possibility of exposure to a gas leak, and that satisfactory ventilation is provided in outdoor areas. This is supplemented by measures which either reduce the presence of effective ignition sources or render possible ignition sources harmless in the event of a gas leak. In other words, ignition source control will involve a number of specialist disciplines in a design team.

To protect and safeguard against ignition of flammable liquids and explosive gases, potential electrical and non-electrical ignition sources must be systematically mapped. Necessary technical, operational and organisational measures must also be taken to minimise the risk of ignition.

Areas where explosive atmospheres can occur must be classified, and equipment and safety systems in classified areas must meet requirements for use in Ex areas.

2.7.3 Ventilation and weather protection

The effect of natural ventilation must be assessed and documented. All air intakes must be located in non-Ex areas and be as far as possible in practical terms from potential HC leaks. Outdoor work areas must have adequate weather protection in order to reduce the danger of health problems and errors. The desire for natural ventilation may conflict with the need for weather protection. Electrical installations must be designed with safety measures and other protection so that abnormal conditions and errors which could pose a threat to personnel and the facility can be avoided.

2.7.4 Detection, emergency shutdown, pressure blowdown and warnings

Platforms must have a fire and gas detection system which ensures rapid and reliable detection of incipient and full fires and gas leaks.

The emergency shutdown system must prevent abnormal process conditions developing into a hazard or accident, and limit the consequences of accidents if they occur. It must be possible to halt HC flows to and from the platform, and to isolate and/or separate off fire areas on the platform.

The blowdown system (gas emissions) must prevent escalation of hazards or accidents by rapidly reducing the pressure and quantity of ignitable gas in the process equipment. Design of a blowdown system is important since the flare boom is a large and dominant structural element on an offshore facility.

2.7.5 Communication equipment

Communication equipment and associated power supply must be designed and protected to ensure that the performance requirements are maintained in hazard or accident conditions.

2.7.6 Firewater and fire pumps

Firewater supplies and fire pumps must be able to fight fires, cool down equipment and structures, and dampen gas explosions if this can reduce explosive pressure. Permanently manned facilities must have a firewater supply from fire pumps or other independent source to ensure that capacity is adequate at all times even if part of the supply system is out of operation. Fixed fire-extinguishing facilities must be installed in Ex areas and in areas with a high risk of fire

2.7.7 Emergency power

The emergency power supply/system must ensure adequate electricity supplies for equipment and systems which need to continue operating during an emergency.

2.7.8 Escape and evacuation

Escape and evacuation will be ensured through a combination of several means of evacuation, such as helicopters, freefall lifeboats and escape chutes with liferafts. On field developments encompassing two or more platforms, a bridge to a nearby facility will be regarded as a means of evacuation.

3 Goliat

3.1 Overall project description

3.1.1 Location and reservoir description

Goliat lies in the Barents Sea, 85 kilometres north-west of Hammerfest and 50 kilometres south-east of Snøhvit. See Figure 3-1. The operator for the licence is now Vår Energi (previously Eni) with a 65 per cent interest and with Equinor as its partner (35 per cent).

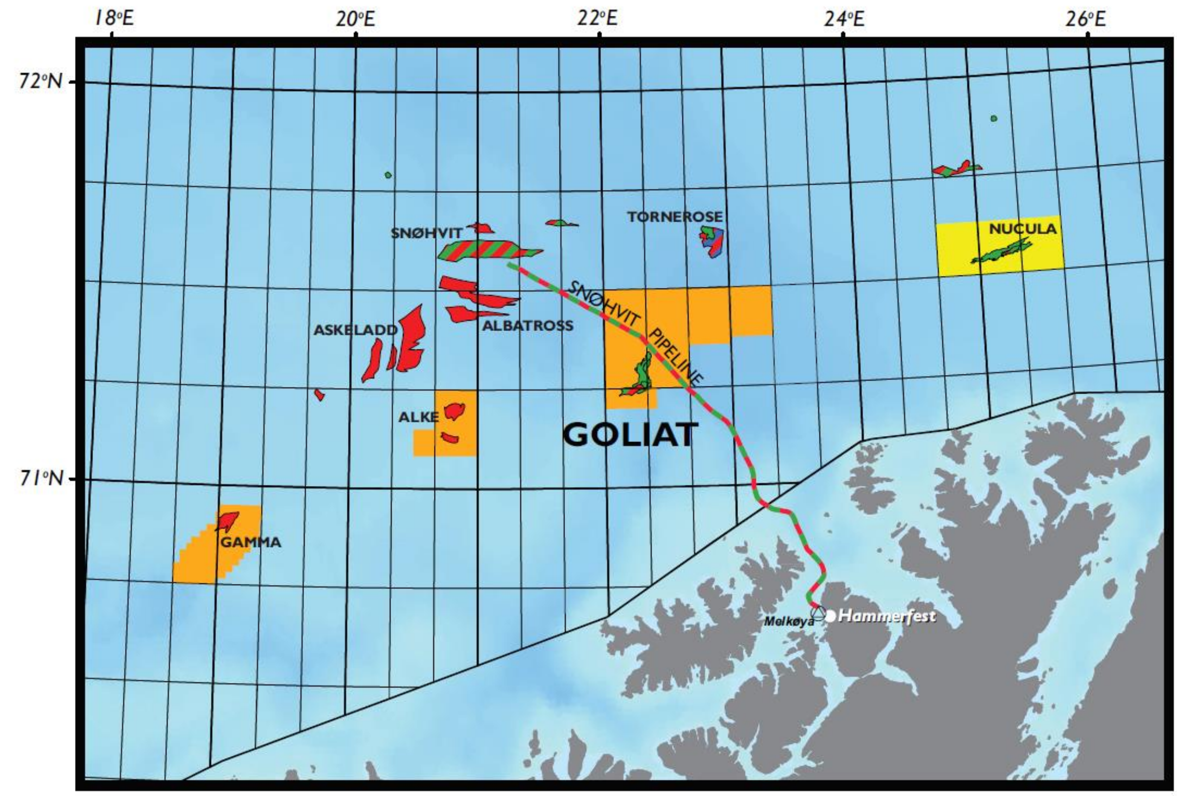


Figure 3-1. Location. (Source: Eni)

Goliat was proven by exploration wells in 2000, 2001 and 2005.

Two appraisal wells were drilled in 2006 and 2007, and the development comprises two reservoirs, Kobbe and Realgrunnen. See Figure 3-2. Total oil reserves are about 175 million barrels (28 million scm). See Figure 3-3 for further details.

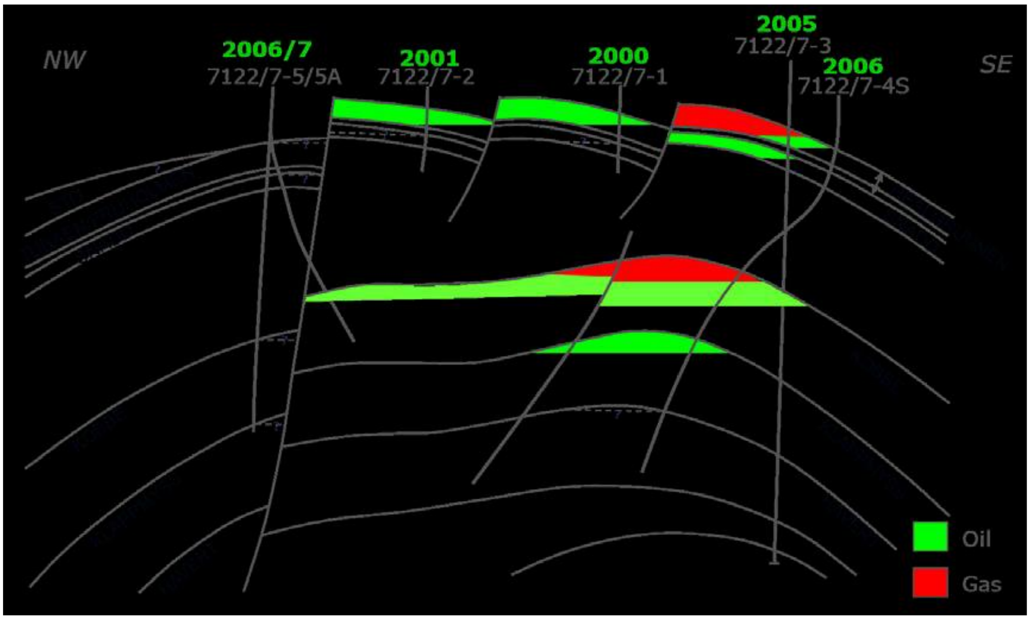


Figure 3-2. The Goliat reservoirs. (Source: Eni)

The water depth over the Goliat field is 320-420 metres, a moderate depth for operations tailored to the use of umbilicals. Pressure and temperature are relatively low, since the reservoirs lie at shallow depths. Associated gas is being used initially for gas lift operations in Realgrunnen, the shallower formation, and will thereafter be injected into the deeper Kobbe reservoir.

	P10	P50	P90	Mean	Base Case
Kobbe oil in place	42.9 MSm^3 (-27%)	58.5 MSm^3	84.5 MSm^3 (+44%)	60.7 MSm^3	59.3 MSm^3
Realgrunnen oil in place	25.2 MSm^3 (-20%)	31.6 MSm^3	44.0 MSm^3 (+39%)	32.6 MSm^3	33.8 MSm^3
Goliat total oil production	18.24 MSm^3 (-28%)	25.17 MSm^3	32.91 MSm^3 (+31%)	25.2 MSm^3	27.88 MSm^{3*}

Figure 3-3. Overview of reserves. (Source: Eni)

In the PDO documentation, the field was to be developed with 22 wells (11 oil producers, nine water injectors and two gas injections). The current plan is 12 oil producers, seven water injectors and three gas injectors – a total of 22 wells.

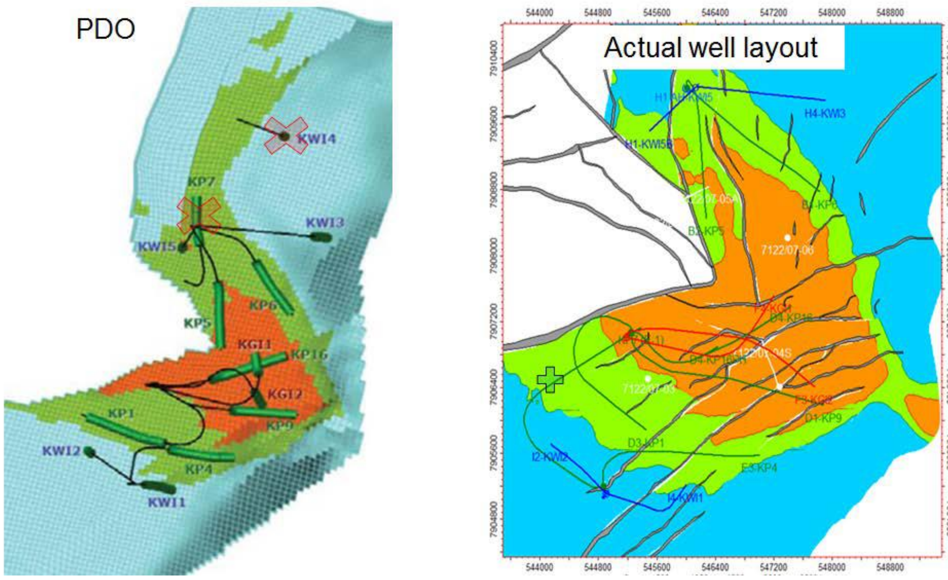


Figure 3-4. Goliat well paths. (Source: Eni)

The seabed topography is very uneven and has presented major challenges in terms of flowline and umbilical routes. However, the oil and gas qualities provide good flow properties, which is important for stable operation/flow in the reservoir.

3.1.2 Licence overview and project description

Figure 3-5 presents the timeline received from the operator (above). The most important issues listed for each project phase are presented below.

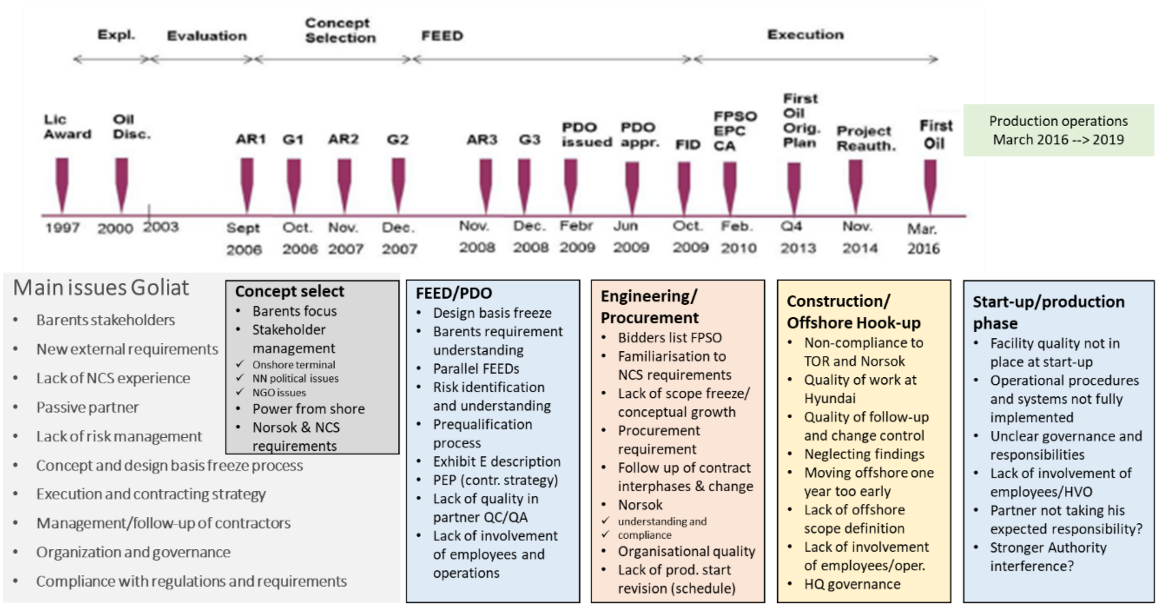


Figure 3-5. Goliat licence history and project challenges. (Sources: Milestones Eni, Acona)

Figure 3-6 provides an overview of the main elements in the development concept.

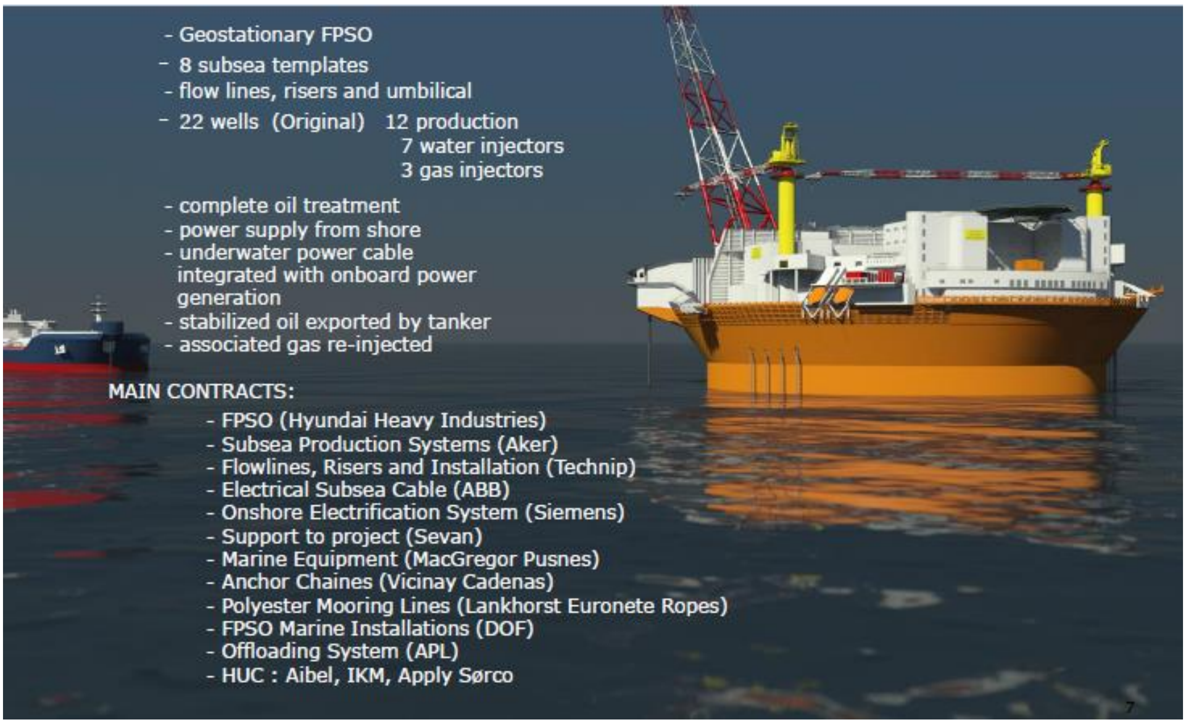


Figure 3-6. Concept overview. (Source: Eni)

FPSO design capacities

- Oil production rate 16 500 scm/d
- Gas production rate 3.7 Mscm/d
- Production rate 12 000 m³/d
- Liquid production rate 17 500 scm/d
- Water injection rate 20 000 m³/d
- Gas injection rate 3.5 Mscm/d

3.1.3 Development of plans and costs over the project's lifetime

Key milestones for the overall project are listed in Figure 3-7 and Figure 3-8.

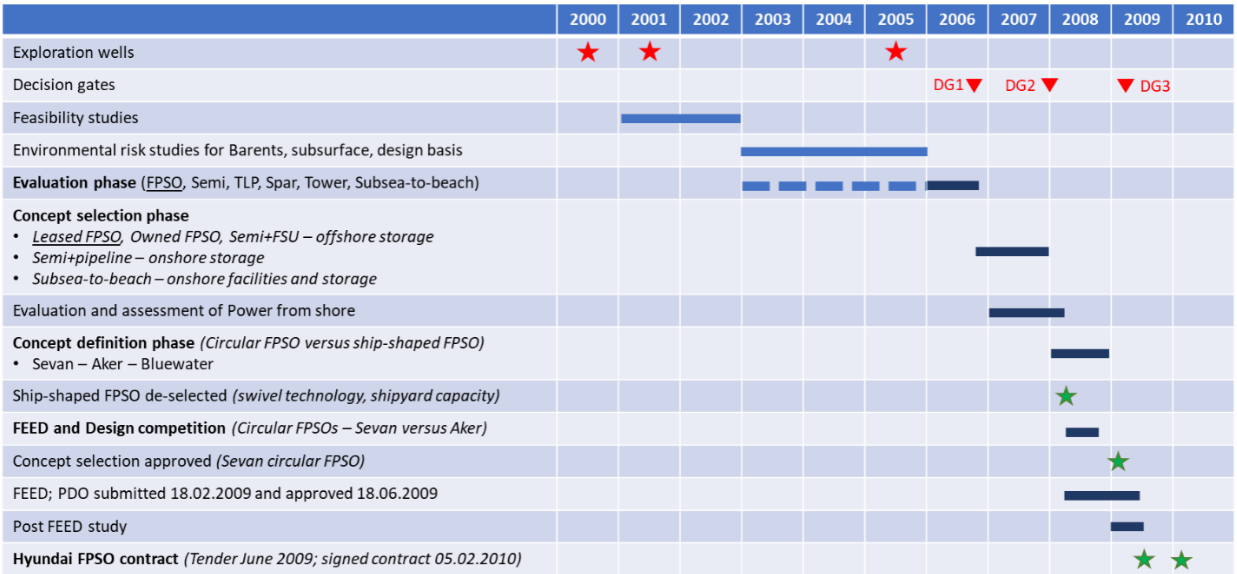


Figure 3-7. Schedule for the early phase. (Source: Acona)

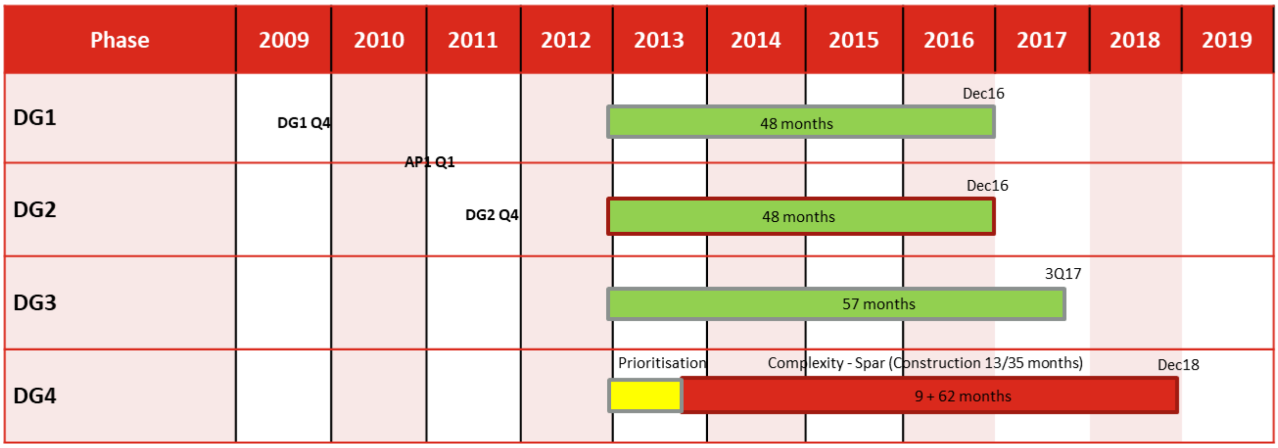
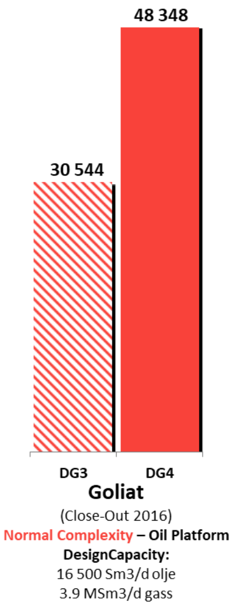


Figure 3-8. Execution – plan development. (Source: Acona)

Figure 3-9 gives an overview of the most important cost elements at DG3 and DG4. Figure 3-10 provides a graphical presentation of changes over time for each main element in the estimate.



GOLIAT			
MNOK	DG3	DG4	DIFF
Management	3 945	6 694	
FPSO	12 118	-	
Topside	-	14 523	
Living Quarter	-	-	
Completion	-	2 566	
Substructure	-	902	
Mooring, Offloading & Inst.	-	1 342	
Risers & Flowlines	2 406	2 987	
Heavy Lift and Transport.	-	-	
Extend./Remaining Scope	-	868	
Contingency	-	-	
Facilities – Platform	**18 469**	**29 882**	**+ 61%**
Facilities – Subsea & Pip.	2 818	2 996	
Drilling & Well	**8 186**	**10 479**	
Power Supply incl. Infra.	897	1 278	
Host	-		
PMT/Petek	-		
Preparation for Operation	174	207	
Insurance	-	553	
Adjust. (Currency impact)	-	2 953	
Phase 1	30 544	48 348	
Phase 2			
Total (Project Close-Out)	**30 544**	**48 348**	**Close-Out16**
Total – RNB 2019	32 600	50 800	MNOK'16

MNOK

DG3 - Total Topside Dry weight 18 202 tonnes

DG4 - Total Topside Dry weight 27 752 tonnes

Figure 3-9. Capex – cost development. (Source: Acona)

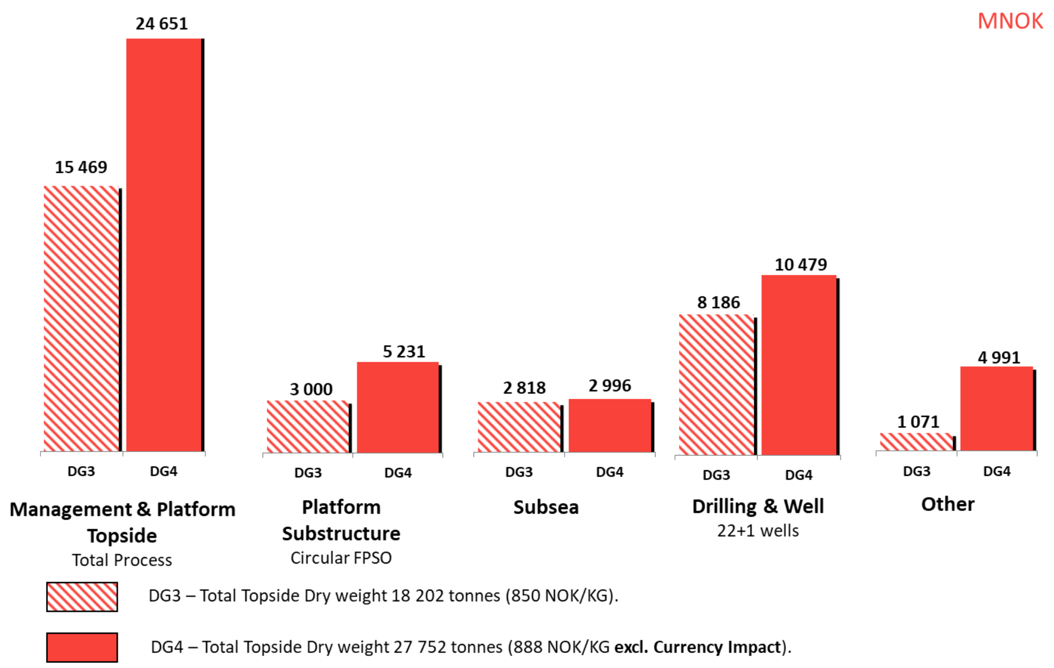


Figure 3-10. Main elements – cost development. (Source: Acona)

During the spring of 2011, the concept was frozen and a new level established for the topsides dry weight at 28 500 tonnes. The final figure came to 27 752 tonnes. The scope of work for the topsides rose from 18 202 tonnes at DG3 to 27 752 tonnes at DG4 – in other words, a weight increase of over 52 per cent.

According to the project's close-out report, the total cost estimate rose by NOK 17.8 billion from NOK 30.5 billion at DG3 to NOK 48.3 billion at DG4. Execution time for the project lengthened by 28 months, from 58 at DG3 to 86 at DG4.

The main contributor to the cost increase was the platform topsides, which had been underestimated. Combined with weak execution, this caused the costs to rise by a total of NOK 9.2 billion, including the operator's management/follow-up.

The scope of work/complexity also increased for the Sevan floating support structure, with costs here rising by NOK 2.2 billion. Rig rates rose for drilling and well completion, and total drilling costs were up by NOK 2.2 billion.

Productivity at Hyundai Heavy Industries (HHI) was poor, and it only received compensation for a small proportion of the construction hours. It thereby showed a substantial loss.

Engineering time was underestimated, and assessed at 1.3 million hours on contract award. Experience from similar facilities would have suggested three million hours. Where engineering design is concerned, an hourly rate of USD 115 and a productivity of 105 hours/tonne is fairly similar worldwide.

Fabrication time for the topsides was estimated at four million hours on contract award, but ended up at 10-12 million. Hourly rates and productivity in fabrication/installation vary substantially

According to Acona's experience database, hourly rates in the Far East are about 40 per cent (USD 45) below the Norwegian level, which is USD 115. Of this, USD 75 is direct and USD 40 indirect. Productivity in the Far East (350 hours/tonne) is expected to be half the level of Norwegian yards (175 hours/tonne). The choice of platform supplier was motivated by the desire to achieve a fabrication/installation saving of around 30 per cent.

Completion (the "I" in EPCI) was put at about 500 000 hours in the contract and then increased to 1.3 million. In addition came a carry-over of 1.5 million hours, which ended up at well over two million.

Total costs for the topsides, including the operator's management/follow-up rose from NOK 15 469 million at DG3 to NOK 24 651 million at DG4 – in other words, a 59 per cent increase. The price per kilogram was nevertheless relatively constant, but climbed from NOK 850 to NOK 888.

When the PDO was submitted, the project had a breakeven price of USD 50/bbl. But part of the work scope had been omitted, nor was the cost of the qualification programme included. In addition came low technical maturation and an unrealistic plan. The expected breakeven price at PDO submission was therefore undoubtedly closer to USD 55/bbl. But the upsides for the project, which lies in a virgin area where new smaller discoveries in the vicinity could be realised, was undoubtedly given substantial weight.

The economics of the project have been hit by an extended project period and a substantial cost increase. On the other hand, the increase in recoverable volumes has had a positive effect. Future oil prices combined with new commercial discoveries in the area will influence the final profitability assessment.

3.2 From licence award to choice of concept

3.2.1 Discoveries and delineation up to DG1 – autumn 2006

Goliat was proven by exploration wells in 2000, 2001 and 2005. Two appraisal wells were drilled in 2006 and 2007. A number of simple field development studies conducted during this period provided the foundation for a consolidated design basis. Concepts involving production facilities offshore and on land were evaluated.

- Of these solutions, only an FPSO gave acceptable profitability.
- DG1 (autumn 2006) was passed with low costs for drilling/subsea facilities and with leasing a small FPSO unit (inadequate capacity in relation to the field's size). This was the only solution which satisfied the licensees' required return at that time.
- Leasing of production units is best suited to small fields with a short producing life, where residual value/re-use could be significant.

3.2.2 Influence of "Barents focus" – politics, environment and regulations

Expectations were aroused in 2008-12 over possibilities for major discoveries in the Barents Sea. Players in the NCS were awaiting the announcement of the 22nd licensing round.

In anticipation, the industry had initiated a number of activities aimed at being as capable as possible of developing oil and gas fields in a safe and economic manner. Although primarily directed at the NCS, these activities also covered the Arctic region. There was a race to get into position and strong competition to secure new exploration acreage on/in:

- the NCS
- the Russian continental shelf (Barents Sea East, the Kara Sea and the Pechora Sea)
- areas around Greenland
- eastern Canada
- Alaska.

The players were governments, international collaboration bodies (the Arctic Council and so forth), the big international oil companies, state oil companies, research institutes and the supplier sector. Norway's offshore industry was strongly placed and worked actively to secure new assignments, particularly with:

- floating structures designed for Arctic conditions
- subsea deliveries
- drilling and well services
- environmental technology.

Russo-Norwegian collaboration in the Barents Sea (the RU-NO Barents project) and other initiatives also contributed to identifying technological gaps and new proposals for technology development. The most relevant players in a global context participated in these projects. Guidance on the parameters for HSE – particularly from the Norwegian government, but supported by the Russian government as well – set the bar high. Demands for zero-emission solutions and oil-spill response arrangements for icy waters, in particular, called for the development of new technological solutions.

The industry's starting point was that major accidents must be avoided. At the same time, it was important to get across that the level of safety for operations in Arctic areas had been raised and that new and better technology would be developed.

International oil companies competing for positions not only on the NCS but also in the rest of the Arctic sought to outdo each other in coming across as leaders for HSE. The head offices of these companies emphasised that their environmental and safety requirements here were significantly stricter than those applied in the rest of the world. This meant that projects such as Goliat could not rely on established company requirements and rules, but largely had to develop its requirements as work progressed.

The Goliat development was based on Norsok standards. Several of the most relevant of these were being revised in 2011-12. This work made slow progress, partly because of the ongoing conflict between the ISO and the API over international standardisation and coordination. Where Goliat was concerned, the revision status of the N series (offshore structures) was particularly significant. In N-003 *Actions and action effects* (rev 2007), for example, Goliat was placed within the boundary for sea ice. However, it fell outside this line in the 2011 revision proposal (first published as a new official version in 2017).

Through conscious choices, the Goliat project set a high bar for HSE requirements in relation to the position described above. That had the following consequences:

- new project specifications had to be produced – many of them with completely new requirements for the suppliers
- new technology had to be qualified
- substantial extra follow-up and training of suppliers was needed.

3.2.3 Feasibility studies – evaluation phase 2006 – DG2

A project team was established to assess a broad spectrum of development solutions. See Figure 3-11. The following were assessed:

- leased FPSO
- owned FPSO
- semi-sub combined with a storage ship on the field
- semi-sub in combination with pipeline to a land terminal for oil storage/export
- offshore subsea facility, pipelines to production facility on land.

This selection requires no special comment. Similar assessments are known from other projects. Integrated drilling facilities were also assessed for the two options with a semi-sub, but the reservoir's properties and extent meant that such a concept was not considered commercially acceptable.

Economic analyses were conducted for all the concepts, along with systematic evaluations of:

- HSE and the working environment
- technology status
- reservoir utilisation
- business development
- operation
- socio-economic significance
- value creation.

The concepts with subsea installations and onshore processing were promoted by external stakeholders on the basis of experience with Snøhvit and Ormen Lange. Public opinion (politicians, organisations and local communities) regarded such solutions as attractive, both for environmental reasons and with regard to jobs on land. However, they are more appropriate for gas than for oil, primarily because of flow technology conditions. Piping the Goliat wellstream ashore would have required substantial technological development.

The main conclusion was that the FPSO solutions (various types) came out best, and that those which included land plants were either unfeasible or unprofitable. A stand-alone offshore development was also found to have the smallest negative environmental impact.

Eni Norge therefore recommended to the partnership in December 2007 that continued work should be based on a circular FPSO, but that alternative versions existed which needed to be further developed up to DG2. This choice rested on two grounds:

- the concept could be realised with either ownership or leasing
- power from shore via a submarine cable would be straightforward.

Power from shore was an important argument because of every stronger pressure from organisations and politicians to adopt this approach offshore.

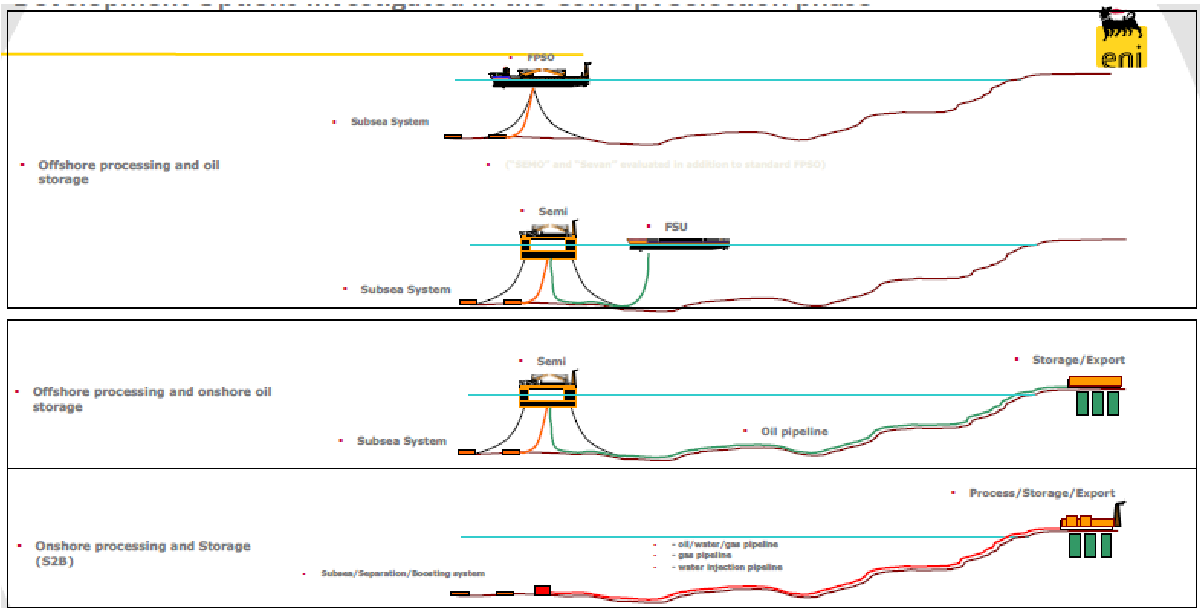


Figure 3-11. Concept options. (Source: Eni)

3.2.4 Assessment of technical safety in the concepts studied

During the selection phase, Eni looked at three main concepts for field development, each with several sub-options. An HSE programme was established, which defined acceptance criteria for the Goliat project, activities to be pursued, and goals for the work in this phase – primarily to establish HSE requirements for the design and ensure that these were implemented in governing documents for later project phases. Eni Norge has made it clear that the project organisation acknowledged the expectations aroused by and the responsibility involved of being the first operator with a development in the Barents region, and therefore did not want to rely solely on minimum or conventional requirements for HSE.

Where HSE in the concept selection phase was concerned, Eni Norge's attention was concentrated primarily on the climatic and geographical challenges posed for an offshore facility in this part of the Barents Sea. Power from shore was assessed for all solutions. Since that involved the use of new technology on offshore facilities, while great uncertainty prevailed about the availability of electricity from the onshore grid, the decision was taken to put this aside at this stage and return to it for specific assessment in the next phase.

Eni Norge followed up all the contractors involved in studies during this phase to ensure that consistent attention was paid to HSE and that acceptable solutions were incorporated. That included working meetings with participation from Eni's project organisation, among them personnel with experience of Barents Sea operations, and from the study contractor, where the topic was the need for and effect of weather protection. Conclusions from these meetings later led Eni to commission the development of a special solution for fixed wind screens which optimised air throughflow while reducing the wind chill effect to an acceptable and comfortable level. Eni writes in its concept selection report that it realised there was a degree of uncertainty about the weather data available at this stage and that it therefore had to increase confidence in this information base so that the winterisation studies in the definition phase would be more relevant. See the PSA's audit of weather data in 2008, which identifies an inadequate information base.

To strengthen the project organisation's expertise, Eni Norge hired a Norwegian consultancy with specialist knowledge of risk analysis and technical safety. All overall (technical) risk assessments carried out in this phase were done by that company. This ensured that the same methodology was applied in analyses and assessments for all the concepts, which simplified comparisons between the various solutions. In order to rank the latter with regard to HSE, a system was developed where the various concepts were awarded "HSE points". The results of this comparison formed part of the decision base when choosing concepts to be taken forward to the next phase.

Eni likens its concept phase to what is known in the Norwegian petroleum industry as a "class C" study. This phase normally leads to a conclusion where only one solution continues into the next project phase, which is Feed.

During the concept phase, technical HSE work should normally concentrate on documenting that the chosen solutions provide an acceptable level of risk and can be regard as being as low as reasonably practicable (Alarp). Furthermore, the system solutions must satisfy the best available technology (BAT) principle. Attention should also be given to identifying incidents with a major accident potential, making it possible at the end of this phase to document that adequate risk-reducing measures have been included. In the working environment field, it is important to identify various forms of working environment risk in the concept phase as well as preparing a strategy for dealing with these risk factors. A supplementary risk matrix will be an important basis for such aspects as further development of the layout and specification of equipment packages, as well as for defining continued work on the working environment for the subsequent Feed phase. When such identifications are not done in the concept phase, the Feed stage will start with a sub-optimal information basis.

Based on information obtained both from conversations with people who played roles in Eni's project team during the concept phase and from Eni's concept selection report, none of the platform solutions studied had an HSE design which would have satisfied what would be regarded in a Norwegian context as a class C study. Eni itself notes in its report that several of the variant offshore facilities studied had substantial design deficiencies, particularly for weather protection.

Solutions for and the extent of weather protection have a big effect on weight estimates for the topsides and, if the scope of such protection is underestimated in an early phase, it can have a big impact later on explosion accident loads, for example. Increasing explosion loads could in turn mean a weight rise. When uncertainty attaches to the weather protection solution for an offshore project, it represents a risk factor for the project as a whole.

The failure of the concept studies to satisfy established requirements for maturity is demonstrated by a comment from partner StatoilHydro in its assessment of DG2 maturity. The following is quoted from StatoilHydro's review:

> RISK MANAGEMENT
>
> Risk register is prepared but is not complete and certain risk elements seem to be underestimated (e.g. schedule risk low). Risk register have to be updated. There are significant differences between the Eni risk matrix and the corresponding one at StatoilHydro for Goliat. The StatoilHydro matrix seems more realistic.
>
> SCHEDULES AND COST ESTIMATES
>
> The cost estimate provided by the operator is considered too low and does not qualify as class C. Alternative cost estimate developed by StatoilHydro is considered to be more realistic.
>
> The main conclusion regarding compliance with DG2 requirements is unchanged. The proposed schedule is unrealistic, and the cost estimates are generally on a class B level. The project is not ready for a "normal" Feed and the allocated duration for Feed studies/PIO preparation is too short. Outstanding issues from the planning phase together

with technology qualification (case dependent) will have consequences on the execution which are probably not captured in the proposed durations.

3.2.5 Concept definition phase

Because the relevant suppliers had rights to the technology, it was now considered necessary to conduct a design competition. During the first quarter of 2008, Aker Solutions, Bluewater Energy Services and Sevan Marine were invited to participate in this. The competition was conducted in three phases up to September 2008:

- familiarisation/prequalification
- Feed
- tendering phase.

As early as after familiarisation/prequalification, it became clear that combining a ship-shaped solution with power from shore would be difficult. Agreement was reached in the licence during the first half-year that a leased FPSO should be shelved and a possible unit of this type would be owned. Prequalification yielded a number of surprises, and found substantial shortcomings in expertise/capacity at several possible suppliers, such as Bluewater, Sevan, HHI and CB&I.

Furthermore, it became clear that Aker would base fabrication primarily on Norwegian yards, while Sevan changed strategy and wanted to commit to an EPC solution in collaboration with Samsung Heavy Industries in Korea. Agreement was reached in the licence during January 2009 that the winning concept was the Sevan 1000.

Feed studies were pursued during 2018 with FPSOs, subsea production systems and flowlines/umbilicals/risers. All the platform concepts were characterised by lack of maturity, with inexperienced new players for complex technical solutions. All the suppliers came up with unrealistically low cost estimates and execution plans. On the basis of this work, an official choice of concept was made in January 2009. This was the real choice of concept in the project. A normal DG2 maturation was not in place until the summer/autumn of 2009 (after the “post-Feed” contracts).

The subsea installation is designed and outfitted with components which are standard solutions for use on the NCS. They have been selected with design and quality for use on Goliat in accordance with the production conditions there, and as the requirements have been developed and described in Norsok, the ISO and the API.

The overall HSE, production and operational philosophy for the subsea installation as described in the PDO with appendices is well-adapted to the field and environmental conditions in the Barents Sea. This is particularly evident in the choice of the following solutions, with great attention paid to environmental and safety considerations:

- electrical heating of pipelines rather than extensive use of chemicals
- SSIVs on all risers, despite the low pressure in Goliat
- use of 36-inch conductors and purchase of new BOPs to reduce the effect of wellhead fatigue
- zero discharge philosophy for discharges to the sea.

The PDO was submitted on 18 February 2009 – in other words, immediately after the choice of concept. A demanding Feed phase had been conducted in the project, with two concepts in parallel and a relatively short time frame. The Feed studies conducted did not meet the normal standards set for such work.

3.2.6 Assessment of technical safety for the selected platform concept

The concept recommended and chosen for Goliat is an FPSO with subsea wells tied back to it. The surface installation is a circular, permanently moored floater with integrated storage and offloading systems. This type of production facility is in use on the UK continental shelf, but has not previously been adopted on the NCS.

A permanently moored floating platform has been chosen instead of the ship-shaped solution more traditionally seen on the NCS. Such a unit makes it simpler to pull in an electricity transmission cable from land. The platform is powered partly from shore and partly from a gas/liquid-fuelled turbine. That reduces the need for local power generation on the facility compared with a solution based solely on gas turbines. See also appendix C.

The platform is specially tailored to the cold climate in the Barents Sea, with extensive weather protection/winterisation. Account has been taken of special requirements for these waters, in that no produced water will be discharged to the sea during normal operation. The platform is designed to provide oil storage in its hull, with the process plant and living quarters above. The hull is built in steel with double bottom and sides.

Figure 3-12. Offshore loading on the Goliat field. (Source: Eni)

Oil is landed via shuttle tankers. Direct loading from a geostationary, permanently moored facility is new for the NCS. The tanker stays on station with the aid of a dynamic positioning system which ensures that the minimum distance between platform and vessel always exceeds 150 metres. During loading operations, the tanker will not normally lie bows-on to the platform. See Figure 3-12. The platform incorporates a large oil store and generally has great flexibility for adding new risers and umbilicals. This opportunity to attach more risers makes the facility suitable for functioning as a future field centre.

The topsides are constructed of modules installed on a circular steel hull, with the process deck having a diameter of 107 metres. See Figure 3-13. This deck was originally intended to be placed five metres above the main deck, which forms the top of the hull structure. After the PDO had been submitted, however, the need to increase the height required substantial changes. The process deck is supported by the radial support frames in the hull, and this load distribution principal has been implemented on all process deck levels. There are two levels above the process deck.

The process deck is divided by an explosion-proof wall running east-west.

Area north is the safe side, with cranes, quarters, lifeboat stations, generators, space for electrics/instrumentation/telecommunications, workshops, stores and so forth.

Area south is covered by a steel structure for protection against wind and weather, and contains five modules – flowlines, separation, gas recompression, gas compression and water injection, produced water and chemical injection. In addition come the primary/ secondary loading station and bunkering station, flare boom and escape chute (the secondary loading station has later been removed).

The flare boom and related equipment are placed as far as possible from the quarters and the safe area.

Pursuant to the PDO documentation, two areas would be provided on the platform for offloading oil. The primary station is positioned to the north-east of the topsides, with the secondary station on the western side. This was intended to permit offloading to continue regardless of wind direction while simultaneously maintaining high regularity should one station be out of operation. However, it was decided at a later stage to the remove the secondary station.

The utilities area on the west side is dedicated to electrical equipment at various levels, with the heaviest components on the process deck. A number of safety functions related to fires and emergencies are on the east side, along with stores and the workshop area. The primary and secondary areas for material handling are located in the centre of the process deck. Cranes are positioned on the north-west and north-east sides.

The living quarters are dimensioned for a crew of 120 people, with single cabins and all necessary facilities. The helideck is placed above the top storey of the living quarters and cantilevered towards the north in order to achieve a direct view down to the sea surface.

Figure 3-13. Illustrations of the Goliat topsides layout. (Source: Acona)

The hull is a circular cylindrical structure with a diameter of 90 metres. Twenty ballast tanks are arranged around the periphery of the hull to provide the latter with double sides and bottom. That reduces the possibility of damage to the oil storage tanks.

Two separate machinery rooms are provided in the hull for the installation of small items of operating equipment. See Figure 3-14. These areas are placed in the central shaft and in the forward machinery room beneath the living quarters. They contain such equipment as pumps, heat exchangers and other utilities. The shaft is divided vertically, with an internal quadrangular section in the centre which functions as a safe zone, while the external section is an unclassified zone. Stairs and personnel lifts are among the facilities in the safe zone. The shaft is outfitted for safe transport of equipment which will require maintenance or replacement during production. Located at the north side of the platform, beneath the living quarters, the forward machinery room primarily contains utility systems for the living quarters like sewage and waste water systems. Equipment such as coolant pumps for seawater, firewater pumps at the lowest level, and liquid supply is found here. A personnel lift rises to the process deck.

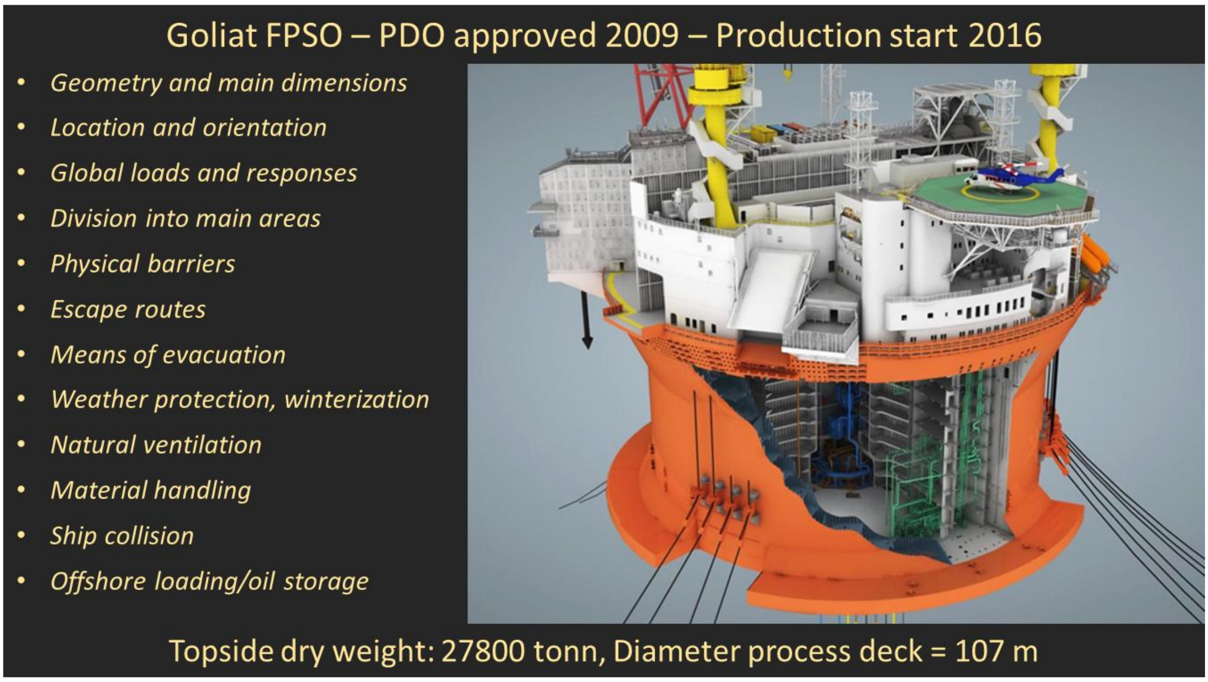


Figure 3-14. Goliat FPSO with listing of safety-related topics. (Source: Acona)

3.2.7 Operator's safety analyses and assessments

Figure 3-14 presents an overview of important safety-related topics assessed by the operator in the early phase.

In the PDO documentation, the operator emphasised that technical solutions selected would have built-in safety and a low level of risk, and meet the parameters applicable to discharges to the sea and emissions to the air in the Barents Sea. The facility would also have a fully acceptable working environment and take care of the challenges created by the climate.

The Goliat development was to be based on the HSE requirements in Norway's petroleum regulations, including the international and national standards referenced in these rules – primarily those from the ISO/IEC and Norsok. The facility is divided into fire areas as on other similar installations.

Acceptance criteria were established by the project for:

- personnel risk when on or being transported to/from the platform
- personnel risk for particularly vulnerable groups
- probability for loss of main safety functions on the platform
- pollution from the platform.

These criteria were to be regarded as minimum requirements, and efforts would be made to develop solutions which reduces risk to personnel, the environment and material assets over and above the criteria (Alarp processes).

The project pursued analyses in parallel with concept development work, which comprised hazard identification and qualitative and quantitative risk assessments. See Figure 3-14.

Personnel risk was illustrated and quantified with calculated FAR values. The biggest contributions came from:

- process
- helicopter transport
- work-related accidents
- tank accidents
- ship collisions
- risers.

Fire and explosion analyses were performed for the platform. To minimise the consequences of possible riser leaks, plans called for SSIVs to be installed upstream of the flexible production risers, with opportunities for manual blowdown of these.

With an eye to collision risk, the traffic pattern of tankers, fishing boats and other vessels in the area was mapped in addition to the known frequency of visiting shuttle tankers.

Calculations for the facility showed that the hull had sufficient strength to withstand the defined accident load. Sectioning of the hull prevents it from sinking as a result of collisions with ships. All oil storage tanks are well protected behind ballast water tanks, which form a double well and bottom structure. All conductors for pulling in risers and umbilicals from the subsea installations, as well as power transmission cables from land, were incorporated in the ballast tanks because that provided good protection against the external environment and collision loads.

Specific recommendations for further work on the PDO embraced:

- climate-tailored design solutions
- detailed explosion simulations
- evacuation and fire load studies
- continued work on Alarp evaluations
- continued work on means of evacuation (lifeboats).

3.2.8 Risk understanding and worker participation

Involvement by workers/safety service/unions in the early/planning phase was minimal.

At the time, Eni had no separate department for offshore production operations in Norway. However, some project participants had previous production experience.

Looking at risk assessments presented in the partnership before PDO submission indicates that the project was preoccupied with Barents Sea conditions and requirements, reservoir understanding, and well and logistics challenges. In retrospect, it can be seen that virtually all these risks were handled in a good way (because they were identified and therefore dealt with).

On the other hand, little can be found on such subjects as:

- expertise/available capacity in the supplier market
- Eni Norge's competence for implementing a demanding project in the Barents Sea
- the Milan head office's understanding of Norwegian requirements and culture
- a correct HSE culture and requirements for quality in the execution
- strategy for contractor/supplier follow-up (including realistic schedules)
- establishing a production organisation, with all associated procedures and systems in place, in good time before start-up.

3.2.9 ASD/government's assessment of the PDO

When considering the PDO, the ASD and the PSA had the following comments:

> The Petroleum Safety Authority Norway recommends that the plan for development and operation of Goliat be approved. The Ministry of Labour and Social Inclusion supports the Petroleum Safety Authority Norway's conclusion.
>
> Preventive safety work will reduce the probability for acute discharges/emissions to the natural environment from petroleum operations. The HSE regulations are risk-based – in other words, safety and emergency preparedness measures must be proportionate to the risk in each activity. Among other things, this ensures that solutions for preventing acute pollution and for dimensioning oil-spill response are tailored to the activity's distinctive character and location. The regulations require in part that region-specific conditions are taken into account when managing risk in the sea area.
>
> This means, for example, that stricter requirements are set for the activity in vulnerable areas than in those which are less vulnerable. The consequence is that activity in vulnerable areas can involve substantial additional costs for the industry in the form of technology development, acquisition of knowledge and expertise, and operations, even though the regulations are unchanged. Strict regulation and supervision in the petroleum

sector represent important contributions to preventing and combating acute oil spills. These measures are therefore combined with an increased commitment to auditing petroleum activity in vulnerable and valuable areas.

The established regulatory and supervisory regime for the petroleum industry will thereby also contribute to taking care of HSE with possible new activities and in vulnerable and valuable areas. In addition, the operator must obtain the Petroleum Safety Authority Norway's consent to starting drilling activity. In its application, the operator must document to the government that it is able to implement the planned activity in accordance with the regulations.

3.3 From DG2 to the selection of main contractor

3.3.1 PDO process

Following the official choice of concept in January 2009, Sevan was awarded a post-Feed contract to continue developing the basis for a new tendering round. A concept fee for the Sevan concept was also agreed.

An ITT was issued in June 2009 to the following consortia:

- Aker Solutions/Samsung
- Saipem/DSME
- HHI (CB&I as engineering subcontractor)

The contract was awarded to HHI on 5 February 2010.

It became clear in this phase that the technical basis from Sevan had *major weaknesses*. That related primarily to the topsides, which represent the bulk of the costs for an FPSO.

Analyses of weight, weight composition, density and space utilisation can provide good indications of the quality and robustness of the basis. Sevan had clearly failed to provide sufficiently qualified expertise and methodology in this area during the Feed phase.

Weight control was crucial for maintaining control over the project. First, a strong correlation exists between weight and costs. Both material and fabrication costs are proportional to weight. However, this does not mean that driving down weight always pays off. Exaggerated weight optimisation causes excess equipment density, which is unfortunate both for operations and safety, while making construction more complicated.

Weight and its distribution (centre of gravity), particularly on floating facilities, can be crucial for buoyancy and stability in every phase: construction, transport, installation and production.

Post-Feed work showed that the quantity of equipment had been underestimated and that space was far too limited in certain areas, illustrated by key figures for density and space utilisation. Major changes were made to the layout and estimated weight rose from 18 202 tonnes (see the PDO) to 21 009 tonnes (see post ITT, December 2009, rev A).

Costs/market rose by more than 100 per cent from 2004 to 2008, and then became more constant. This was not taken fully into account in the cost estimates. The PDO/DG3 was submitted in February 2009 with a cost underestimate. According to information from the interviews, partner Equinor added several billion kroner to Eni's estimates in its board decision and thereby found the economics to be even more marginal than the government could read from the official PDO document. In other words, the project was marginal, with an underestimated facility and an overoptimistic execution plan.

The PDO was submitted on 28 February 2009, and this date is also referred to as DG3. In the view of this study, that was too early in relation to project maturity. However, oil policy in northern Norway (Lofoten and the Barents Sea) was a hot topic in the general election campaign at the time. Securing a Storting decision in the spring of 2009 was also important for those who felt it was necessary to get projects under way in the Barents Sea.

3.3.2 The MPE's assessments and conditions – Proposition no 64

Summary: Given expectations at the time for costs, production and oil prices, the Goliat development was assessed as marginally commercial by the licensees. Its robustness to reduced oil resources, higher investment costs and oil prices below current forecasts was low. The licensees therefore included a reservation in the PDO that they would review project profitability before awarding contracts in the autumn of 2009.

The gas would be injected for pressure support during an initial phase, but was expected to be recoverable at a later date.

A plan on increased use of power from shore on Goliat would be submitted by the licensees to the MPE as soon as the regional electricity supply position strengthened, but in any event no later than 1 January 2010.

> **Conclusions and conditions:** The MPE approves the plan for development and operation of Goliat in accordance with the plans presented by the operator and the observations communicated in the Proposition, and on the following conditions:
>
> 1. The operator must assess whether capacity can be increased in the transmission cable for power from shore. This assessment must be submitted to the ministry before a contract is entered into with the cable supplier. The ministry can order the operator to increase the capacity of the cable.
> 2. Provision must be made for connecting an additional cable for transmitting power from shore to the facility.
> 3. The licensees must inform Statnett SF not later than 31 December 2009 of consumption requirements related to full power from shore from 2017.
> 4. Plans must assume a strengthening of the central grid in the Hammerfest area in 2017, depending on the licensing process.
> 5. Two years before the field comes on stream at the latest, the operator must submit a plan for disposal of gas from Goliat to the ministry. This plan must include an opportunity for disposal of gas from Goliat from the time the field comes on stream.
> 6. In light of special challenges in the far north and the Goliat field's proximity to land, oil-spill preparedness must be given a very high priority.
> 7. The operator is expected to follow up measures which will increase the local and regional spin-offs from the Goliat development.

Comment: This indicates that the robustness of the project was considered low when approval was given, and that the government was particularly concerned with environmental considerations and resource utilisation.

3.3.3 Contract strategy

Figure 3-15 presents a diagrammatic overview of which contractors/organisations would be responsible for various parts of the work of executing the Goliat project. As can be seen, a great deal was left to EPC contractors. The success of such a contract strategy depends on a good and precise definition of the scope of work for each contract. It also requires the contractor to have developed good and relatively detailed plans for how to conduct detail design of the facility, how to carry out materials procurement and, not least, how to build the facility (construction philosophy). None of this was in place to a good enough standard when the contracts were entered into.

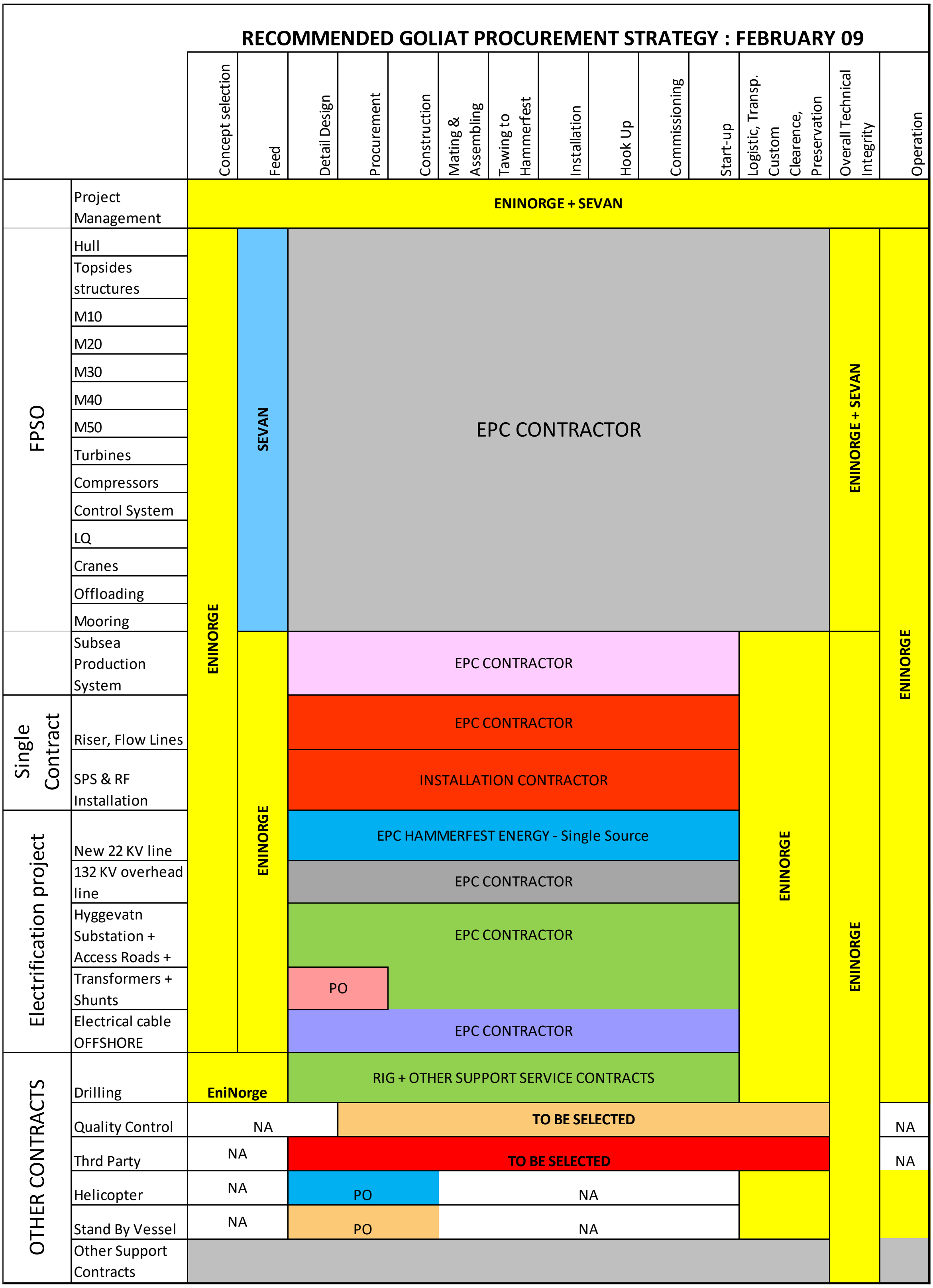


Figure 3-15. Contract overview for Goliat. (Source: Eni)

The consequence of the hasty decisions was a weak Feed basis with fairly serious underestimating, which was only partly corrected by the post-Feed study.

Underestimating weights created problems for detail design and gave direct rise to cost increases. An experienced partner like Equinor should have raised this with the operator.

3.4 From contract award to start-up

3.4.1 First phase after contract award to HHI – 2010-11

The Goliat FPSO contract was awarded to HHI on 5 February 2010, 10 days earlier than planned, and the subcontract for “global engineering” was placed by HHI with CB&I on the same day. The constellation of HHI/CB&I with assistance from Sevan seems risky given the earlier experience of these suppliers with international deliveries. Sevan had carried out little in the way of fabrication studies that far, which meant little detailing of the construction method had been done and big changes became necessary

Good practice for concept development covers fabrication studies – in other words, equipment layout, modularisation and hook-up – combined with good systematics for weight estimation. The Sevan concept is not designed for efficient construction. See Figure 3-16. Nor does it appear that construction was an important issue before the contract award to HHI.

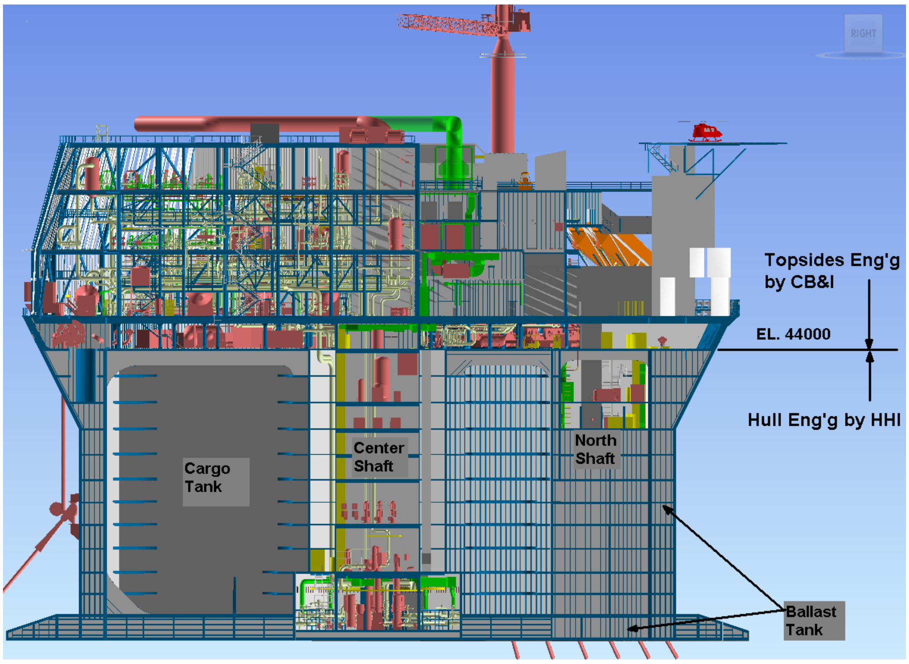


Figure 3-16. Goliat sectioning. (Source: Eni)

As early as March, it was reported that HHI was behind schedule on the mobilisation plan, and it became ever-clearer in subsequent months that progress with detail engineering of the topsides was poor. The players (operator and EPC contractor) had little experience of large and complex projects, and little learning or experience transfer appears to have occurred in this phase.

Substantial weight increases for the topsides were reported in September 2010. See also the separate section on weight. The weight issue attracted great attention in the following months. Weight estimates continued to rise, but began to decline after weight-reduction measures were instituted and stabilised at a level considered acceptable in terms of transport and operational stability. However, reserve capacity for future loads declined.

Lack of progress in detail engineering was reported as a main problem throughout the first year after contract award. The construction method chosen also resembled building a land plant rather than an offshore platform, with optimising simple prefabrication given priority over weight optimisation. Weight increases were not seen as an HHI problem.

The large number of topsides sections hooked up on board led to a massive accumulation of work on the actual platform.

CB&I was demobilised after eight months of global engineering in London. Its collaboration with HHI functioned poorly. The contract awarded by the latter to CB&I lacked the right commercial incentives to do a good and thorough job.

Engineering procedures are HHI were assessed as acceptable, and detail design was transferred to it despite concerns over its lack of experience with Norsok standards. Efforts were made to compensate for this with courses, but it was found that personnel taught the Norsok standards were often moved to other projects.

3.4.2 Assessment of weight and cost control

Weight control is crucial for maintaining control of a project of this type.

- Strong correlation between weight and costs.
- However, excessive equipment density is unfortunate for construction-friendliness, safety, operation and maintenance.
- Weight and its distribution (centre of gravity) can be critical for stability and buoyancy in every phase, from construction and transport to installation and operation.
- High initial weights reduce flexibility with regard to future expansions or modifications.

The weight challenge relates primarily to the topsides. With the Sevan concept, topsides and hull weights are in the same order of magnitude, but the former costs a lot more and has high centre of gravity, which is significant for stability. The hull has posed no problems worth mentioning.

All the signs are that expertise has been inadequate in the early development of the Sevan concept and that insufficient attention has been paid to weight, weight estimation and weight control.

Based on the Feed study, the PDO (18 February 2009) specifies dry weights of 18 202 tonnes for the topsides and 33 166 for the hull.

An estimated cost was presented in December 2009 (post ITT, December 2009, rev A) with dry weights of 21 009 and 30 727 tonnes for topsides and hull respectively.

The topsides weight estimate remained stable until September 2010, when big weight increases were reported. This attracted great attention. At that time, the estimated dry weight for the topsides was 30 000 tonnes.

A special work group was established for weight, and technical reviews were arranged – including one with Equinor. It was established that HHI had a good grasp of weights in the various disciplines, that reporting was detailed and accurate, but that HHI was conservative with regard to unforeseen weights and showed little concern for keeping weights down. HHI gave priority to simplifying design and construction rather than optimising weight.

Opportunities for weight reductions were identified, and a new level for topside dry weight of about 28 500 tonnes was established in the spring of 2011, which was maintained throughout the rest of the project. This is illustrated in Figure 3-17, which also shows that the hull presented fewer problems.

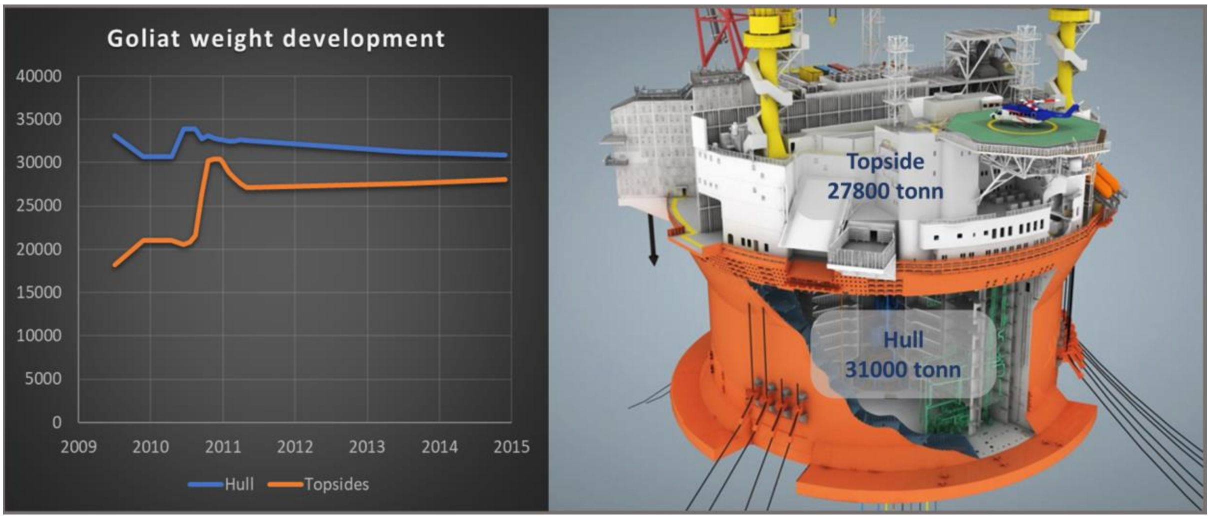


Figure 3-17. Weight development for hull and topsides. (Source: Acona)

This level for weights brought the position under control with regard to both transport and stability/buoyancy in the production phase, but it has been significant for flexibility in relation to future modifications and possible expansions of the facility. See Figure 3-18.

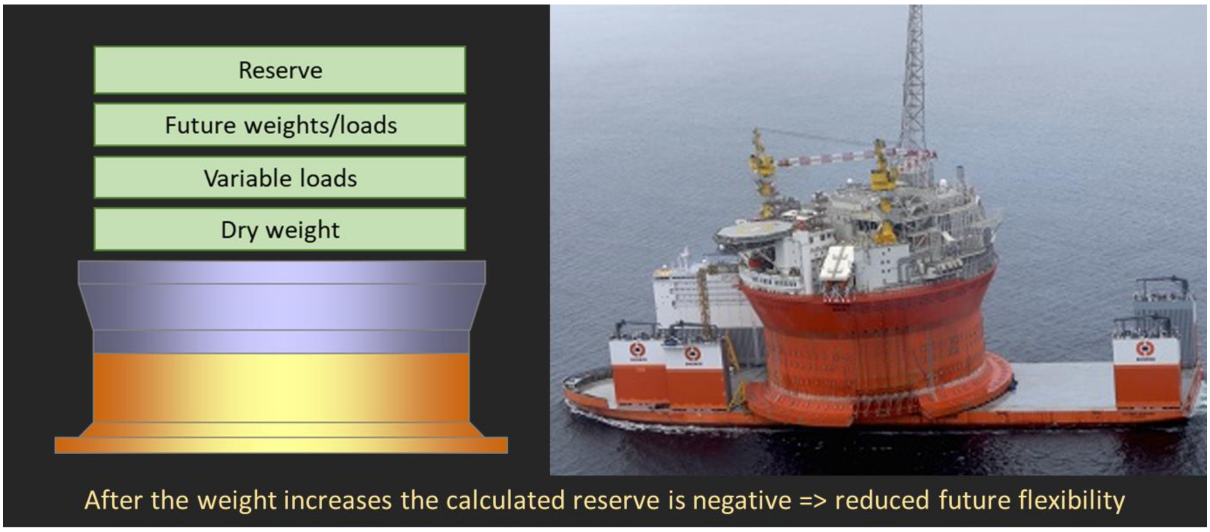


Figure 3-18. Weight categories and reserve. (Source: Acona)

Topsides dry weight provides the basis for cost calculations and is an important figure for weight reporting and control. Normal practice is to divide it between equipment weights, bulk weights per discipline and construction steel. Weight composition varies from platform to platform, but a marked deviation from the average should be investigated in more detail.

Figure 3-19a presents discipline weights in relation to equipment weights. Weights for the Goliat topsides are compared with average values for 16 different platforms. Figure 3-19b presents discipline weights as a percentage of total dry weight for Goliat and for the reference projects.

The figure shows that Goliat has high bulk weights and a lot of construction steel in relation to equipment weights. Bulk weights for electrics and piping are unusually high. Why this should be the case has not been fully clarified, but a possible cause is the fairly unusual topsides layout as a result of the circular hull. Where electrical systems are concerned, it is reasonable to suppose that the concept with both power from shore and offshore electricity generation, along with winterisation, has been significant.

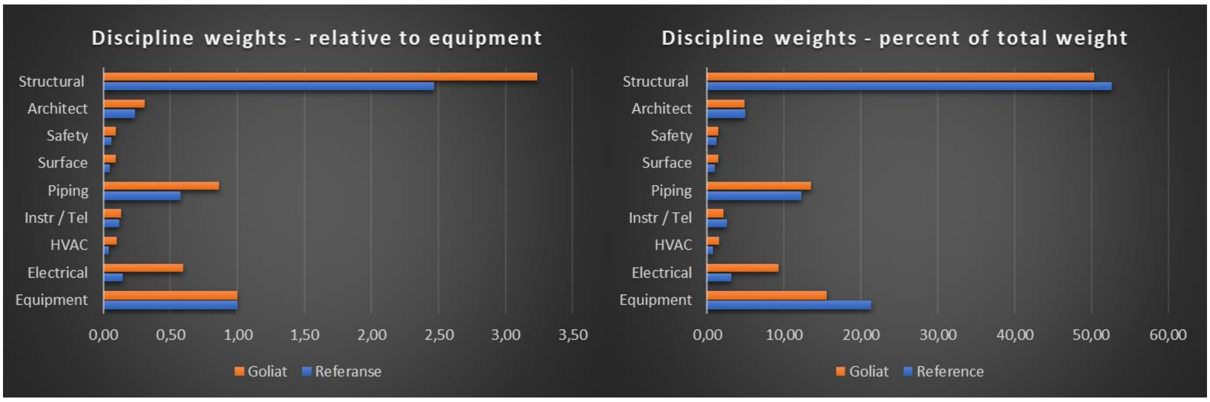


Figure 3-19. Analysis of discipline weights. (Source: Acona)

3.4.3 Sevan concept – construction

Good practice for concept development includes fabrication studies. Emphasis must be given to equipment layout, modularisation and hook-up, combined with good systematics for weight estimation. Based on long experience, a practice has been established for offshore facilities which recommends assembling equipment in a few large modules with well-defined interfaces. That provides opportunities for building modules and the support structure in parallel. A limited number of interfaces minimises hook-up work. This practice splits work between various fabrication sites and reduces overall construction time.

The Sevan concept is not designed for efficient construction. It appears that this was not an important issue before the contract award to HHI. The approach described by HHI involved building the hull entirely in dry dock, with the topsides installed on the completed structure. The topsides were to be constructed as a large number of small sections, which were then lifted on board for assembly into larger units. This led to a massive accumulation of work on the actual platform, which is assumed to have had a big impact on productivity. In other words, a construction method was chosen which more closely resembles building a land plant than a modern offshore platform.

This choice was a consequences of the actual Sevan concept, because the circular hull made it difficult to adopt topsides mating or lifting of large modules. Post Goliat and on the basis of new studies, however, Seven has proposed that large modules should be built and that the radial support system be replaced by rectangular systems. An orthogonal support system would have given better volume utilisation and simpler construction. Module installation could be conducted as a combination of lifting and skidding.

3.4.4 Ability of the platform EPCI contractor to accept turnkey responsibility

A reimbursable price format was primarily applied in the EPCI contract. In other words, up to 85 per cent of the costs were paid against invoices. This was contrary to the desire of Eni's top management for a fixed-price contract.

The EPCI contactor failed fully to fulfil the contract/responsibility concerning management/follow-up of subcontractors, progress reporting, costs/change orders, updated plans, quantification of the risk picture with measures and so forth. The project had major deficiencies in management and risk understanding. HHI lacked E and P expertise, but nevertheless wanted to manage itself. Work was substantially delayed from the start. The technical basis had been little matured and the whole EPCI execution was distorted.

With the initial collaboration over engineering between HHI and CB&I functioned very badly, progress on maturing and detailing was minimal in the early period. Eni ended up putting 25 of its own staff on the case, while HHI had five people following up CB&I in London. The scope of engineering was also underestimated by about 1.3 million hours in the tender, when experience from similar facilities would have given more than three million hours.

The quality of the engineering design work done and the follow-up by HHI were so poor that Eni checked much of the documentation and drawings itself.

The project made negative progress for several months because of correcting faults and deficiencies. CB&I's expertise with and understanding of Norsok was weak. After eight months, HHI in Korea took over the rest of the engineering design work but also had a substantial shortage of engineering expertise with this type of facility.

Another area which caused substantial problems for the quality of the facility as well as a big cost increase was procurement of materials and equipment (the P in EPCI).

HHI was responsible for procuring and following deliveries of materials and equipment. The description of work scope and the delivery specifications were initially inadequate (to a great extent because of problems with design progress and expertise).

In addition, HHI made a minimal effort to follow up this part of its EPCI responsibility. Ultimately, that forced Eni's project organisation to take over the job. This "mitigation" measure was put in place far too late, which meant deliveries were late and of inadequate quality – and produced in turn rectifications and delays in the construction phase. A good deal of the deliveries came from Norwegian suppliers. An important observation is that these deliveries were on average no better than those from international or Korean contractors. In other words, the failure lies with the organisation responsible for the whole procurement process.

The construction method from Sevan/HHI basically lacked detail, and a number of big changes were made. Since Goliat was a small player at the yard, occupying five per cent of its capacity, the project had problems obtaining priority and manning was low at first.

HHI's yard has a capacity of 25-30 000 workers. At full capacity, the majority are hired in from subcontractors. That normally has a big negative effect on productivity.

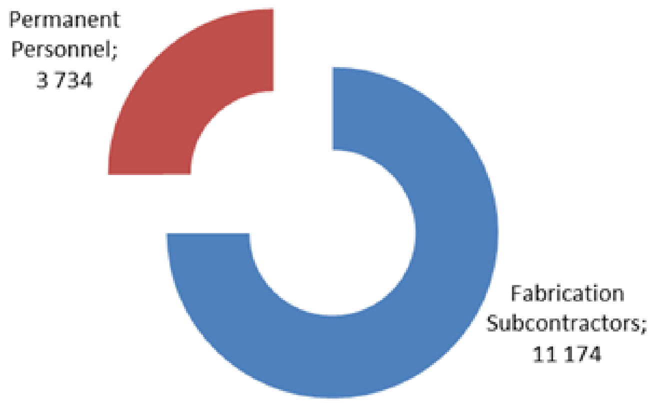


Figure 3-20. Manning overview HHI. (Source: Eni)

Large parts of the construction were allocated to the shipyard, which lay eight kilometres away and which traditionally worked on simple standard products. Productivity plunged completely in the spring of 2015, and quality was so bad that the project lost three-four months of progress. The number of workers on the topsides was initially high. All the changes and rectifications required worsened the position considerably and resulted in very poor productivity.

3.4.5 HSE at the construction site

The order backlog at HHI was very high during the construction of the Goliat FPSO, and the number of employees and contract workers rose substantially. HSE statistics from the Goliat FPSO project show that the yard faced big and growing challenges in maintaining personnel safety. In particular, the relationship between the frequency of reportable conditions/incidents and serious incidents changed dramatically in mid-2014, and serious incidents exceeded reportable incidents in frequency. This shows that HSE management at the yard was deficient or absent. Responsibility for HSE supervision at construction sites always rests with the national government (in this case South Korea).

This negative relationship between the two HSE statistics persisted until fabrication was completed. However, the lost-time injury frequency remained relatively stable throughout.

Eni Norge had a relatively large HSE presence at the yard from the start. This largely comprised consultancy, but the group was expanded in 2013 by two additional Eni Norge staff. The company established a group at the yard to follow up compliance with Norwegian regulations. Eni's organisation at the yard had dedicated resources for following up working environment aspects.

Eni ran several training programmes for HHI personnel, including work at a height, an introduction to Norsok and flange control. A programme to improve HSE understanding at the yard was also launched early in the construction phase, and a customer group was established to pursue and follow up the yard's HSE activity. The programme for HSE understanding was delivered by an external consultant (JMJ Associates with the incident and injury-free (IIF) programme) and was actively followed up (and paid for) by Eni and other yard customers.

This initiative worked with HSE awareness and direct training of HHI personnel. More than 1 300 people had undergone this training by 2013. Big signs showing HSE status were erected, and access control imposed for the facility. HHI opted in 2014 to terminate the consultant's work and continue the initiative itself. This did not accord with the customer group's wishes, and HSE results also became must worse towards the end of the year.

The effects of the training were undoubtedly challenged by the big turnover of personnel. Eni introduced a work permit system for activity on the Goliat FPSO, which was managed by HHI under Eni's orders. Eni conducted a construction risk analysis in 2013 with HHI's participation, even though this was probably rather late in the day. Furthermore, sea trials and departure (including HSE) were largely planned by Eni, which demanded the involvement of a third party in the trials.

Quality control has clearly been deficient, and follow-up from Eni was not good enough. The quality control unit had no manager during the final part of the project, for example, and the function/person for following up preservation was only present for a short period of 2013. Nor was third-party follow-up satisfactorily defined and followed up by Eni, and was thereby not done (to any great extent) by HHI. Eni mobilised its contractor for checking lifting equipment at the yard towards the end of 2014.

Eni Norge nevertheless considers the HSE statistics during the construction phase to have been generally good. See Figure 3-21. The exception is the three deaths which occurred – one at the start of fabrication and two close together towards the end.

1. **30 May 2012.** One person died from lack of oxygen after climbing in to inspect a weld in the ballast water system. The investigation report identified the main cause of the incident as: "lack of proper management of team composition related to the activities versus risk related to ongoing work". It also stated that inadequate attention was paid to HSE, thanks to poor or no training.
2. **24 October 2014.** One person died after being hit by a dropped object (flare tip). The investigation report found that the main cause of the accident was the limited attention paid to safe working and safety procedures. It also identified inadequate work supervision on Goliat as another important contributor to the incident.
3. **27 December 2014.** One person died after being crushed between a lift load and the lift-shaft wall. The main reason was identified as the victim's lack of experience and the failure to provide him with adequate training.

The common denominator of these three fatalities is lack of training and poor management at the construction site. HHI's HSE results were so weak in 2014-15 that they attracted attention far beyond South Korea and the yard eventually instituted drastic measures to reverse the negative trend.

It later became known that many of problems with Goliat revealed during start-up and operation were caused by inadequate follow-up of quality in the engineering and construction phases. Many complex causes and contexts explain why the FPSO was delivered to the operations organisation with such a large number of faults and deficiencies.

But Eni's management for fabrication and completion in South Korea emerges as the party which could have made a significant difference if responsibility for quality and safety had been dealt with in a better way.

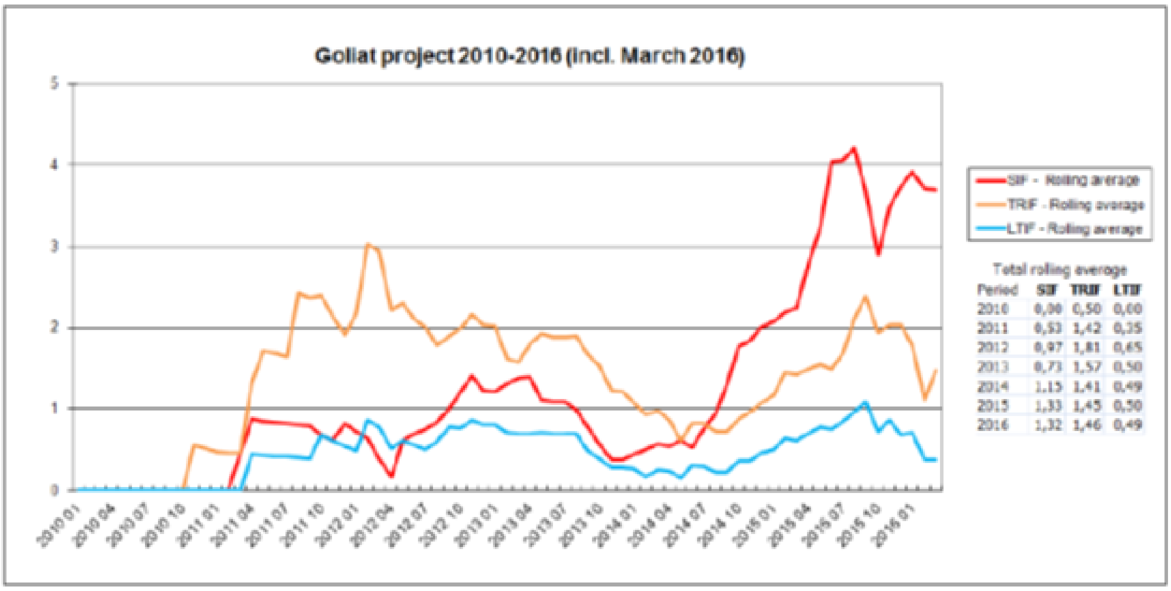


Figure 3-21. Goliat HSE statistics. (Source: Goliat development project close-out-report)

3.4.6 Completion of the Sevan platform

Completion of the project was included in the EPCI contract – in other words, "turnkey for all systems". A yard stay in Norway estimated at NOK 500 million was included in the terms.

The completion personnel/system were replaced during the execution, which meant there was little continuity and new consultants with limited experience arrived. Documentation of what was done and not done at the construction yard was incomplete and deficient.

Actual status accorded poorly with punch lists and other documentation. That posed a very considerable risk for the completion phase in Norway and for a safe start-up.

If this had been known – and it ought to have been – it should have resulted in a stay at a yard in Norway to ensure a full overview of the remaining scope of work before the platform was towed out to the Barents Sea. That would have ensured a safer and probably earlier start-up as well as better quality in the work done and lower costs.

3.4.7 Quality of risk management

Risks were identified and visualised in risk matrices, usually as red risks with substantial consequences/high probability, but it is difficult to determine whether actions were initiated and followed up. These actions were also allocated surprisingly often to people outside the project team, such as required meetings with Eni's top management and HHI. With poor quality and delayed delivery, increased inspection and follow-up should have had priority.

Risk meetings were organised with the executives from operator and contractor present, and critical red areas were identified, but it is again difficult find specific action being taken, and the lack of follow-up does not appear to have had any consequences.

Despite big weight increases early in the project and poor progress with detail design, expectations of cost increases were not reported until 2012. Reported cost rises came in 2012-16, at NOK 6.2 billion in the first year, then NOK 1.4 billion, NOK 7.8 billion, NOK 1.2 billion and NOK 1.6 billion – in other words, a total of NOK 18.2 billion.

Compliance with contractual terms is not achieved without devoting substantial resources to management and verification. Follow-up of procurement packages calls for surprisingly large resources to achieve good quality at the right time and cost. That applies to deliveries from both Norwegian and foreign suppliers.

Experience from other projects indicates that both Norwegian and foreign procurement require the same level of (intense) follow-up to ensure that the specified quality is met.

In addition, the customer generally participates actively/with substantial human resources throughout the process from specification/tender evaluation to approved delivery, even though formal responsibility rests with the EPC(I) contractor. Eni took too long to become involved on Goliat. HHI's own follow-up was weak and of inadequate quality.

Quality risk in procurement was not identified as a serious issue in the project until far along the track. A number of actions were taken on the basis of these analysis, but without much effect.

3.5 Subsea installations, drilling and well operations

3.5.1 Project execution for subsea installations

Project execution for the subsea production system (SPS)

Following a tendering round, Aker Solutions was awarded a contract in 2009 for engineering, procurement and assembly of the subsea equipment for Goliat. The contract covered 22 wells (11 oil producers, nine water injectors and two gas injectors) in eight four-slot templates with associated control equipment and spare parts. Aker Solutions also secured a service contract in 2013 for assistance in installing the seabed equipment.

The contract awarded in 2009 was based on established standard terms for the NCS. It covered 11 work packages split between subsystems and work assignments.

Feedback from Eni on the execution of this contract is generally positive, but with some critical comments directed at the turnover of key personnel and some inadequate exercise of quality control and reporting.

The seabed equipment used on Goliat basically comprises standard components used on many subsea fields. Because of special requirements for Goliat, however, 37 technical qualification programmes were initiated and implemented. This was a substantial number of elements, which demanded much extra time and attention during project execution.

In particular, challenges with wellhead fatigue and injection of wet gas for gas lift created a need to qualify new technology. All the qualifications were successfully implemented in the project. Three comments can be made in that context:

- more thorough preparation of the design and contract base would have reduced the number of qualifications
- delays to the FPSO provided better time for carrying out the qualifications
- Eni felt a strong obligation to make Goliat as good a facility as possible.

The project was executed by Eni and Aker Solutions in a well-established and practised manner for this industry. Technical and commercial personnel from Eni managed and followed up the contract at the various construction sites used by Aker Solutions. Registration and follow-up of nonconformities were handled and reported in accordance with established routines and normal standards.

HSE: Fifty-five HSE incidents were registered for the contract with Aker Solutions from 2010 to March 2016. None of these were in the red category. Many incidents occurred at the start of the fabrication process. After attention had been devoted to the issue, however, a substantial improvement was noted.

Project execution flowlines, umbilicals and risers

A Feed study for flowlines and risers was conducted in 2008 by Dutch company Intecsea. It had the following scope:

- field layout
- design of flowlines, protection and connection
- design of electrical heating for flowlines
- installation

- costs and planning.

Eni reports that this study displayed good quality.

The design base was used in a tendering round during the autumn of 2009. Technip Norge won the contract, which included design, procurement, construction and installation of:

- flowlines and risers
- flexible pipelines
- umbilicals (delivered by Aker Solutions)
- templates with emergency shutdown valves (delivered by Aker Solutions).

Technip Norge split the job into a number of subprojects and entered into contracts with about 20 key subcontractors. Work offshore was conducted in the summer seasons of 2011-15. The scope of work and schedule was tight, particularly considering:

- the need to alter pipeline and cable routes owing to field layout changes
- qualification of new technology – directly heated electric cables
- handling of fibreoptic connectors (delivered by Aker Solutions).

The contractor aimed to complete its part of the work on Goliat within the original schedule. Because of the delay with the FPSO, however, this part of the project also had to change plans.

HSE: According to Eni, 67 HSE incidents were registered for this area, including four with a big potential for harm. Management attention on this issue by Eni and Technip led to a fall in the number of incidents, and better control of the work was thereby established.

Completion of subsea installation, flowlines, risers and umbilicals

After hook-up, the subsea installation, with flowlines, risers and cables, was pressure and function tested in accordance with Norsok standards and Eni's specifications. Operating documentation and procedures were prepared by the respective suppliers and collated by Eni.

3.5.2 Drilling and well

Goliat has 22 wells divided between eight templates. It has two separate reservoir zones:

- Realgrunnen, 1 200 metres below sea level
- Kobbe, 1 800 metres below sea level.

The wells include oil producers and water and gas injectors. Two of the wells are multilaterals. Given its depth, the reservoir has normal pressure and temperature.

Owing to depth, pressure and temperature, these wells were relatively straightforward to drill. The original (PDO) estimate was 1 104 days, while 1 174 were used. The main reason why days used exceeded the estimate was the difficulties which arose from using water-based mud to drill the 12 ¼- and 8 ½-inch sections in the first wells.

Eni has assumed that discharges to the sea from drilling wells on Goliat will be as small as possible, defined as zero discharges. This is described in the following way for the *Scarabeo 8* rig used on Goliat (extract from the annual report for consumption and discharges on the Goliat field for 2017):

> Zero discharge work for drilling wells on the Goliat field includes assessments of chemicals/consumption groups and discharges of drill cuttings to reduce risk and consumption, as well as opportunities to cut the quantity of drilling waste. Other important measures are the use of physical barriers on the rig which prevent discharges of waste and wash water to the sea. Similarly, drainage is separated so that clean and dirty water end up in separate tanks. Routine checks are conducted systematically on the rig to monitor that the barriers are intact and that zero discharge routines are followed. Zero discharge measures are listed below:
>
> - double physical barriers on all lines to the sea
> - adequate tank capacity for oily water
> - liquid additive system (LAS) for controlled dosing of cement chemicals

- system which provides good accuracy and controlled use of chemicals
- all areas were oil and chemical spills could occur are connected to a closed drain system
- two independent systems for checking slip-joint gaskets on risers.

Areas around cellar-deck openings and where discharges could go directly to the sea have raised edges to prevent such discharges. Discharges of cuttings are assessed from a waste minimisation perspective with the aim of reducing the quantity of cuttings discharged, [which] means smaller discharges of drilling fluids.

Comments and observations related to drilling wells on Goliat

The issue of wellhead fatigue was raised in full vigour in the industry at the same time as Goliat was to be developed. This had the following consequences:

- the wellhead design had to be altered
- 36-inch rather than normal 30-inch conductors were used
- the heavy BOP on *Scarabeo 8* was replaced with a new and smaller unit.

Eni applied Norsok D-010 for barrier testing.

Scarabeo 8 was a new rig and its crew took some time to exploit the effect of a twin derrick. Attention was paid to equipment testing before the facility was taken into use. Logistics were a challenge. The drilling and completion programme was developed jointly by Eni Norge and Eni in Milan.

HSE work on the rig functioned well. The stop card method was used. Parallel operations on subsea templates were well-prepared and observed all requirements and guidelines established for the NCS.

Summary

Drilling and completion of wells on Goliat were performed in a satisfactory manner with regard to HSE, technical quality and costs. The technical condition of the 22 wells after three years of operation is evidence of that.

3.5.3 Power from shore

Supplying power from shore to the field was organised as a separate subproject, covering cable fabrication, laying on land and at sea, and pull-in/connection to the platform. A new transformer station was also built at Hyggevatn.

Power from shore was identified at an early stage of the project as an activity area with high risk and the need for further technology development. It therefore attracted great attention. Installation of the system was completed in July 2014, and it was constructed and completed in accordance with all the requirements and conditions set by the NVE.

The submarine transmission cable had been laid by the third quarter of 3014 and readied for pull-in. Connection to the platform occurred in May 2015, followed immediately by testing. The cable has been the main source of power for Goliat since mid-June 2015 and has operated subsequently with good regularity.

3.5.4 Loading system for oil exports

The loading system contract was awarded to the APL division of BW Offshore AS in June 2010, and covered the turnkey delivery of a fully tested system. Considerable development and testing was required to specify the system. The loading hose for Goliat was the first with these dimensions to be stored on a reel while also being approved to API 17K. The amount of testing which proved necessary was underestimated by both the contractor and Eni.

Installation of the loading system went as planned, but the water depth meant testing could not be completed before arrival on the field. The first hose roll-out to a tanker therefore occurred in June 2015, with the first loading operation conducted in March 2016. After the loading system became operational, damage to the hose was discovered and segments of it have been replaced. Visual inspection also revealed damage that could be repaired before becoming critical.

3.6 Offshore hook-up and completion

3.6.1 Execution strategy for remaining FPSO work in Norway

Transport/installation (the I in EPCI) was included in the original EPCI contract. Eni chose to remove these activities from the contract and handle them itself. The original plan called for a yard stay on the Norwegian coast for final readying before installation on the field.

The main reason for going directly to the field seems to have been time-related. A yard stay would have delayed tow-out to Goliat until the spring of 2016 and start-up to the third quarter of 2016 at the earliest.

If the project team had possessed a better overview of remaining work and accompanying faults and deficiencies, a different decision would almost certainly have been taken.

3.6.2 Marine installations and completion

The Goliat platform left Korea on 12 February 2015 and was transported to Norway on a heavy-lift ship. It arrived in Hammerfest on 17 April 2015.

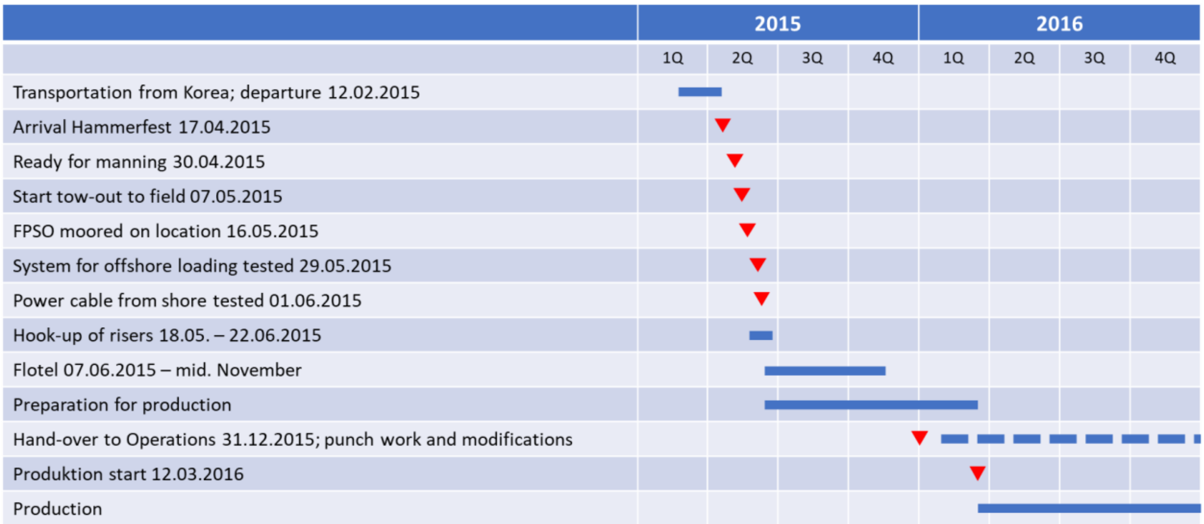


Figure 3-22. Milestones in connection with installation and start-up. (Source: Acona)

The platform was ready to be manned on 30 April 2015, and tow-out to the field began on 7 May 2015. Mooring had been completed by 16 May 2015. The risers were pulled in and connected between 18 May and 22 June 2015. At the same time, the various systems were readied and tested – for offshore loading, power from shore and so forth. The transport stage, mooring off Hammerfest and installation on the field were performed without major problems.

Because a great deal of work was outstanding, preparations to come on stream were delayed. The development project was formally terminated on 31 December 2015.

3.6.3 Increase in scope of work

On departure from South Korea, the management of Eni Norge was aware that a not-insignificant amount of carry-over work remained to be done on the Goliat platform, but the fabrication management had actively downgraded the criticality of deficiency comments over a long period. See, for example, PSA audit of June 2014). It has also emerged from interviews of Eni personnel that this practice involved not only to downgrading, but also failure to register critical and non-critical error notifications. A long series of deficiencies and faults was “discovered” during the hook-up period:

- firewater system: not tested in advance, rearrangement
- firewater pumps: vibration and leaks
- electrical cables: serious deficiencies in relation to Norsok, surplus cables
- hydraulic system: leaks
- living quarters: deficiencies in relation to functional requirements

- SAS: limited capacity created problems in operating the system
- Hummervoll coating: much crack formation
- painting: extensive repairs needed in many areas
- nitrogen helium testing: large number of leaks in connections
- platform cranes: big problems with keeping them in regular operation
- air compressors: vibration and so forth created problems for maintenance and operation
- pressure safety valves: corrosion problems because of poor preservation.

The list was even longer, and showed that the level of quality control with associated documentation must have been unacceptable when the platform left the yard. This was a responsibility which rested on the project organisations at both HHI and Eni.

It also transpired that other extensive modifications were required in the following areas.

- Ballast water system: changes required to conform with Norwegian requirements.
- Seawater injection into the reservoir for pressure support: it transpired soon after start-up that the seawater was not sufficiently treated to be able to flow efficiently into the reservoir. A temporary treatment plant was installed, which increased the volume of work required while bringing the platform on stream. Tougher government requirements on water injection introduced at a late stage in the project were the main reason for this. But this type of challenge can also be generally traced back to inadequate acquisition of reservoir data in the planning phase, and reflects the importance of acquiring such information and conducting well testing before the decision to develop a field is taken. This represents a dilemma in that well testing, with associated flaring of oil and gas, conflicts directly with the desire to be seen to be taking the most environment-friendly approach possible.

It was decided to implement these modifications after the platform had come on stream.

Figure 3-23 lists the total amount of work carried over for completion after platform start-up.

5.1 Goliat extended scope
Ballast Water system
Fire Water
Seawater System
2 Additional Xmas trees (capital spare)
Water Injector Workover
Material Handling and Logistics Improvements
Punch Work Transferred to Operational Phase
Punch Work Related to Tagging and Labeling
Permanent Insulation of Jackets and Boxes
Commissioning Punch Work Transferred to OPR PHASE
Transfere Punchwork data from Procosys to IFS
OTS (Operation Training Simulator) upgrade
Reproduce Power System Alanysis
Repair of Heat Traced Escapeways
Reinforcement Temp Repair 24" SW line
Implementation of EniTime Tools
Review and Update Fire Control Plans
As-built Assistance
Potential Dropped Objects - Insufficient welding
Remaining electrical campaign
PAGA Modifications
Gas detector layout on Main Deck
Air Compressor Modifications Study
Minor Modifications
WI pump discharge valve bypass
Pipe Support Modifications
Rectification work on DOP Frame at EL 76.000.
Management & Administation
Eni - Project management
Offshore Project Supervisor/Management
M&M - General Management & Administation

Figure 3-23. Outstanding work. (Source: Eni)

3.6.4 Commissioning and handover to operations

Commissioning of systems on the platform was based on this being operator Eni's responsibility. But a number of contractors were hired to carry out necessary activities and work under Eni's management:

- hook-up – Aibel (296 000 hours)
- piping and process services (PPS) – IKM (254 000 hours)
- ISS contractor – Norisol (144 000 hours)
- IECT supplier – ABB (extension of HHI and M&M contract – 404 000 hours)
- subsea – Aker Solutions.

This adds up to 1100 000 hours, compared with the original scope of 60 000 plus 94 000 in estimated carry over work. Because of the large amount remaining to be done, it was decided to hire a flotel and *Floatel Superior* was therefore chartered from June to November 2015.

Since the platform was now offshore with a number of systems operational, partial consent was given to begin using the quarters and cranes. This meant more detailed procedures related to work permits and execution than if the platform was at a yard. The most serious deficiencies not identified earlier related to the electrical installations and cabling.

The principles for handing over completed systems from the project organisation to operations had to be revised in relation to the original plan because of the poor completion. The outcome was a two-stage delivery procedure as shown in the flow diagram below. See Figure 3-24.

All handover certificates are available in Procosys, the system used for documenting testing and handover in the Goliat project. Start-up was in March 2016, but three systems had still not been handed over at 31 May 2016 (system 04B – sundry laboratory equipment, system 29 – water injection, and system 44B – produced water, sand treatment).

Discussions on handover of equipment led to uncertainty about the division of responsibility and created to some extent conflicts between the project and operations organisations.

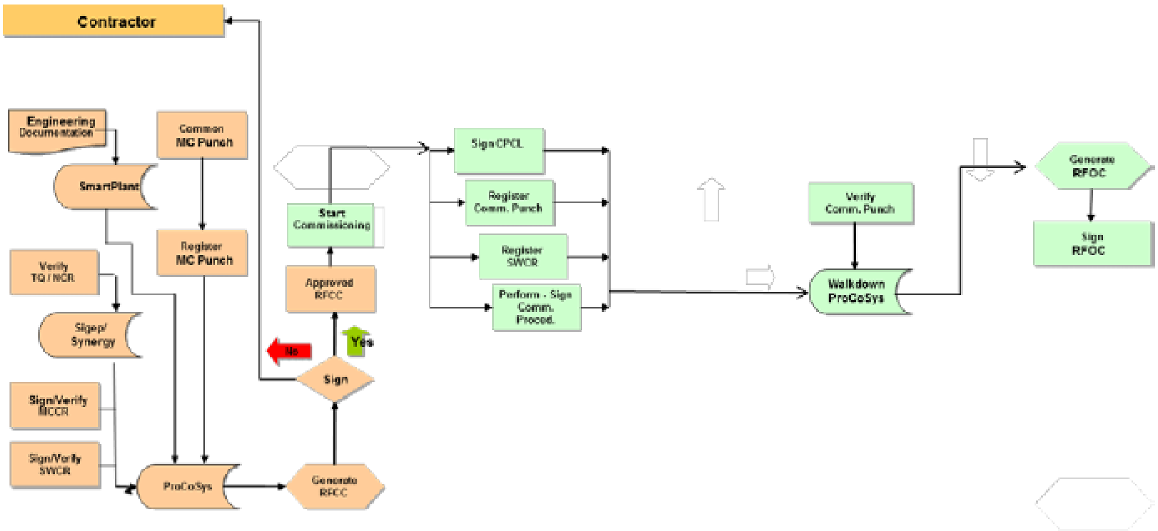


Figure 3-24. Handover of systems. (Source: Eni)

3.6.5 Decision on start-up (based on Auditor General's report, 2019)

This section is based on the Auditor General's report of 2019 and the presentation below is an edited extract from that document.

An application for consent to bring the Goliat FPSO on stream was submitted to the PSA on 13 February 2015. On the same day, the Goliat FPSO began its voyage from South Korea to Hammerfest. At that point, the platform was not completed and the remaining work was to be carried out during the transit to Norway, in Hammerfest and at the platform's permanent location on the Goliat field in the Barents Sea. Eni's expectation now was full production of 100 000 barrels per day by 31 December 2015.

The Goliat FPSO was installed on the field during May. Eni received a partial consent to begin using the platform's living quarters and cranes on 20 April 2015, so that personnel could be accommodated and supplies and materials loaded on board. The PSA continued to consider Eni's consent application, and the start to production was postponed while awaiting a decision. The PSA took a long time to consider the application in order to do a thorough job on the basis of its experience at that point. According to the PSA, this was an unusually long time for dealing with a consent.

During its consideration, the PSA conducted five audits of Eni until its consent was given (from 15 February 2015 to 19 January 2016). The PSA also received seven whistleblowing reports about various conditions on Goliat during this period. Findings from the audits indicated that problems persisted in two areas in particular – logistics and barriers (including electrics/ignition source control).

The PSA conducted an audit of the electrical installations in September 2015 which identified nine non-conformities and eight improvement points. Its audit report noted:

> Based on observations, conversations and information received, our impression is that Eni, at the time of the audit, lacked an adequate overview of the scope of outstanding work associated with completion of the electrical facilities.

The PSA also asked Equinor to assess the decision base applied by Eni to bring Goliat on stream. Equinor wrote a letter to the PSA on 8 January 2016 in which it said that Eni's plan "contains the activities which must be conducted before Goliat can come on stream". It believed the plan was feasible, but perhaps a little optimistic in terms of the schedule for execution. On its own initiative, Equinor went through the points in the plan to assess whether the Goliat FPSO was ready to come on stream. Its report from this verification was ready on 12 February 2016. Equinor's findings include that much work remained to be done and that Eni lacked a full overview of what this comprised. In addition, Eni lacked a shared understanding internally of what work remained before it could bring the platform on stream – including work to map and check ignition sources.

The PSA assumed that the findings in Equinor's report were followed up by Eni and Equinor. At that time, the PSA felt it had no grounds to check Equinor's assessment, and trusted that the responsibility for following up these findings would be accepted by Eni. Equinor told the PSA that problems with regularity would arise after production started, but that it did not regard these as unacceptable in safety terms.

On 19 January 2016, the PSA gave consent to start using Goliat on the basis of the documentation in the application and clarifications made during the consideration process. At that time, Eni had not carried out all the activities and measures in the completion plan. The PSA accordingly made its consent conditional on:

- activities planned by Eni before and after the start to production being completed
- Equinor's verification being implemented and followed up in the licence
- the PSA receiving a final response from Equinor before start-up.

In addition, Eni was to give the PSA written confirmation that the facility was ready to come on stream before it was finally taken into use.

Eni sent a letter to the PSA on 11 March 2016 to say that it was ready to bring Goliat on stream. On the same day, Equinor submitted its confirmation that Eni had done what was necessary to produce petroleum safely. The basis for these letters was a new risk review conducted by the licensees on 10 March 2016. On 12 March 2016, the day after the letters were sent to the PSA, the Goliat FPSO began producing oil. Both Eni and Equinor regarded the conditions for consent to be met when they notified the PSA on 11 March 2016 that production would begin. In interviews, Equinor said that it had expected completion work would take longer, since a good deal of written documentation was still lacking. The official inauguration of Goliat took place on 18 April 2016, the day after production from the platform had been halted by a gas leak.

3.7 Production phase until the spring of 2019

3.7.1 Production preparations and readying for start-up

Eni's strategy was to build up the operations organisation in Hammerfest on the basis of the highest possible local recruitment. In relation to the original schedule, work on establishing this team began too late. A number of the people recruited to it had limited experience. This helped to reduce the influence of the operations organisation on the design of practical technical solutions at the detailed level.

Since the project was eventually delayed (by 2.5 years in all), this should have provided a good opportunity to complete all necessary operational procedures and personnel training. Nevertheless, some deficiencies at start-up have been registered.

Eni's operations expertise at the yard was initially provided by Norwegian consultants. After a time, a number of the future Norwegian operations personnel were also sent to Korea, not only to become familiar with the facility but also to help ensure that the deliveries were of appropriate quality. Conflicts arose between the Italian project management and the operations personnel, who failed to secure acceptance for their proposals. The whole business ended up with many of the Norwegian consultants being sent home and replaced by Eni operations personnel from Italy who were not to accompany the project to Norway.

During the first phase after arrival in the Barents Sea, the division of responsibility between project and operations personnel was unclear. That led to conflicts, a number of undesirable incidents and whistleblowing both internally and externally. The safety service was also not involved to any extent in the first phase. Responsibilities and roles as well as the division of responsibility were only clarified in the course of 2015.

3.7.2 HSE incidents after start-up

From the start of production in March 2016 until this study began, Eni Norge had notified the PSA of roughly 60 incidents. Two-thirds of these had their roots in a genuine incident, while the others were false alarms. Eni has classified two of the incidents as “serious”, with one resulting in serious personal injury. About 10 of the notified incidents concern the discharge of small quantities of environmentally hazardous substances – in other words, with no potential for damaging health.

That reduces HSE notifications for the Goliat FPSO rooted in genuine incidents with the potential for damaging health to about 30 cases spread over almost three years since the facility came on stream. Most notifications came in the first operating year, with annual numbers since then roughly equal.

The incident log reveals that Goliat had a number of running-in problems in the shape of false alarms. It is worth noting that the safety systems reacted as intended in these cases, and emergency response measures were quickly established. The false alarms caused a number of shutdowns, but safety of personnel takes priority over production regularity and was well handled.

Those incidents caused by HC escapes, fires or incipient fires were all of limited or local scope and were all detected by the safety systems on board. Automatic reactions were initiated for these incidents as intended, and emergency response measures were quickly established.

A couple of incidents related to power failures on board and one to failure of power supply from shore (loss of power from land reflects incidents which Goliat operations cannot affect). These incidents led to investigations with subsequent improvements to electrical systems on board. No evidence has been found that weaknesses in the electrical system derive from inappropriate design or other failures in quality control during engineering, procurement, installation or completion.

- 17 April 2016: shutdown because of gas leak. The PSA takes a serious view of this.
- 18 April 2016: official inauguration of Goliat. Gas alarm sounds again.
- 10 May 2016: the electric facilities. Smoke development and power cut.
- 12 May 2016: hydraulic discharge.
- 13 June 2016: unions in Eni send a whistleblowing report to the PSA concerning the company management. They express concern over worker safety.
- 25 June 2016: a man is hit by a steel rope and flown to hospital in Tromsø. His injuries are serious. After the incident, investigations of several conditions are announced by both the police and the PSA.
- 24 July 2016: a flamestopper on the FPSO is found to be not working as it should.
- July 2016: two unions and three chief safety delegates write to the government to express their concern over safety on Goliat and to demand a production shutdown. They warn that a serious accident will happen sooner or later.
- 30 July 2016: attempt at gas-freeing from the flame stopper, but the work is halted because it would release excessive HC. A worker is heavily exposed to the gas. The incident is not reported in the nonconformity system.
- 26 August 2016: power cut incident. A new attempt at gas freeing from the system leads to gas leaks to areas where these are unsafe, a power cut and a production shutdown.
- 26 December 2016: shutdown because of damage to a loading hose.
- 6 January 2017: Eni resumes production after a five-week shutdown.
- February 2017: notification of a hydraulic and diesel oil leak to one of the ballast tanks.
- 27-28 June 2017: NEA inspection reveals two nonconformities: cooling systems have been filled with refrigerant by uncertified personnel, and failure to report discharges of slops to the sea.

- 19-28 September 2017: based on whistleblower reports about unsafe ignition sources, the PSA carries out an audit of this issue and uncovers a number of regulatory breaches which pose a major accident risk. At this time, Goliat is in the final phase of a planned turnaround.
- 3 October 2017: Eni resumes Goliat production after the turnaround despite the information about findings in the concluding meeting of the ignition source audit.
- 5 October 2017: Goliat production is halted as an acute measure after a conversation with the PSA concerning observations made in the ignition source audit. Eni also receives notice of an order to correct safety-critical faults before production can resume.
- 29 October 2017: report of acute pollution. Alarm sounded after a leak of heating medium through an open valve in connection with cleaning. Vapour/degassing from the heating medium has activated gas detectors. Personnel muster to the lifeboats.
- 13 November 2017: Eni receives another order from the PSA after an audit of electrical safety
- December 2017: leak in the emergency power generator. Sixty of the 120 personnel on the platforms are sent ashore.
- 8 December 2017: The PSA notifies that the order which imposed a shutdown of Goliat has been obeyed, and that Eni can resume production.

3.7.3 Goliat – electrical systems and ignition source control

During the completion phase in South Korea and offshore Norway, the PSA carried out a number of audits on various subjects, and identified improvement points and/or nonconformities. Media headlines meant that the problems with the electrical systems, ignition source control and compliance with the Atex directive had attracted particular attention. It emerged from an audit report in October 2015 that Eni personnel have expressed concern in interviews over the quality of ignition source control, and that deficiencies had been identified which correspond with the concerns expressed.

The audit moreover identified deficiencies in the installation of the electrical systems, as well as unclear roles and divisions of responsibility for the electrical workforce. In other words, the PSA established nonconformities and weakness through this audit which affected design, installation and organisation. The consent Eni Norge received to begin production in the spring of 2016 implied that the company had assured the PSA that all nonconformities and improvement points had been or were planned to be improved, and that the description of the improvements indicated the chosen solutions were acceptable. It emerged from an audit in September 2017 that all the identified conditions had been worked on, but that a number of the conditions identified in connection with the 2015 audit were not fully corrected even though Eni had presented these matters as corrected in its communication with the PSA following the audit. It is important to emphasise here that a consent expresses the regulator's trust that the applicant has assured itself that the facility satisfies the regulatory requirements and that appropriate management systems for safe operation are in place and will be followed. The PSA's consent does not mean that the government has recognised the whole design as acceptable.

The deficiencies which the PSA had called attention to in these audits were serious and created doubt about the condition of the safety barriers on the facility. As long as these deficiencies had not been corrected, a higher risk of ignition existed should a HC leak occur and affect the unsecured equipment. The consequences of such an accident could be the loss of several lives and substantial material assets.

Following the audit in the autumn of 2017, Eni was ordered not to resume production before the safety-critical faults had been corrected. It was also ordered to report back to the PSA when the faults were corrected and to refrain from restarting until the PSA had verified that the company had corrected the faults. Following the verification, Eni was called to a meeting to review its results. An unusual step taken at the same meeting was a request to Statoil as a licensee to report on measures through its "see to it" duty for restarting Goliat.

It is worth noting that it has not been normal practice earlier for the PSA to check reports from an operator concerning the correction of nonconformities, since it is the operator's responsibility to ensure that its operations are conducted in accordance with the regulatory requirements.

Another audit of the Goliat FPSO with attention concentrated on electrical facilities and associated equipment was conducted by the PSA in October 2018. The PSA emphasised that the effect of earlier audits with consequent orders had been positive, but that weaknesses and deficiencies were still being identified, particularly with management of safety barriers – including registration and assessment of nonconformities which affected safety-critical elements. Non-conformities identified in this audit resulted in a new order to the operator. Vår Energi was ordered to: "Draw up a realistic and binding plan for completing outstanding safety-critical work on the Goliat FPSO. That also includes completing the status of the technical condition of safety-critical barriers. The deadline for compliance with the order is 1 March 2019. The PSA must be informed when the order has been carried out."

It has emerged from interviews with the PSA that the barrier management system developed for Goliat is considered to have the potential to be one of the best in use on the NCS. In other words, Vår Energi has a good starting point, but has been unable to make full use of the system.

Goliat incidents in Norwegian media

A number of the incidents on the Goliat FPSO have been reported in Norwegian and international media. The headlines have not always been proportionate to the actual incidents, and emergency response measures implemented as part of a procedure to secure an overview of and control over an incident and personnel on board have been cited as evidence of the seriousness of the circumstances. However, emergency response measures such as mustering after an alarm are practised everywhere on the NCS and are carried out in virtually all cases as a precaution. This practice also provides the emergency response leadership with a quick overview of personnel on board, and those with response duties can initiate these quickly and without hindrance.

Many of the media reports which have appeared document that Goliat has a well-functioning emergency response organisation. The platform has not experienced incidents with a major accident potential in this period. Over the same period, corresponding media attention has not been paid to similar incidents on other NCS facilities, even though several examples exist of such occurrences.

3.7.4 On stream – regularity, HSE and safe operation

Goliat came on stream on 12 May 2016. Monthly production during 2016 is presented in Figure 3-25. As this indicates, a number of operating problems have occurred which will be commented on below.

The initial period was demanding. According to a report produced in September 2016, 54 unplanned shutdowns occurred in the first 164 days (about five and a half months) after start-up.

Accumulated oil production during 2016 came to 18.7 million bbl, corresponding to 2 968 000 scm. Output during the first six months (to 13 September) was about 1.6 million scm. See Figure 3-25.

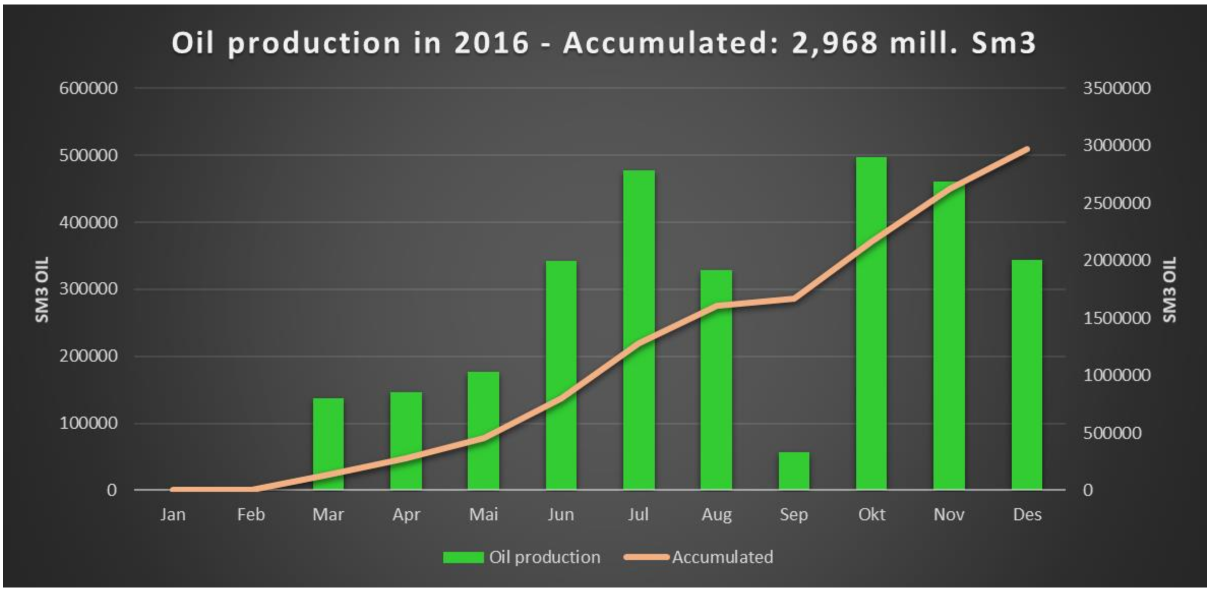


Figure 3-25. Oil production in 2016. (Source: Acona)

Figure 3-26 presents production developments from day to day. The reasons for some of the substantial output losses are indicated. These include HC leaks, false HC alarms and power cuts. The figure also shows that the platform produced some 11 000 b/d in several periods, which is above the nominal capacity of 103 800 b/d or 16 500 scm/d. Gas treatment is the bottleneck.

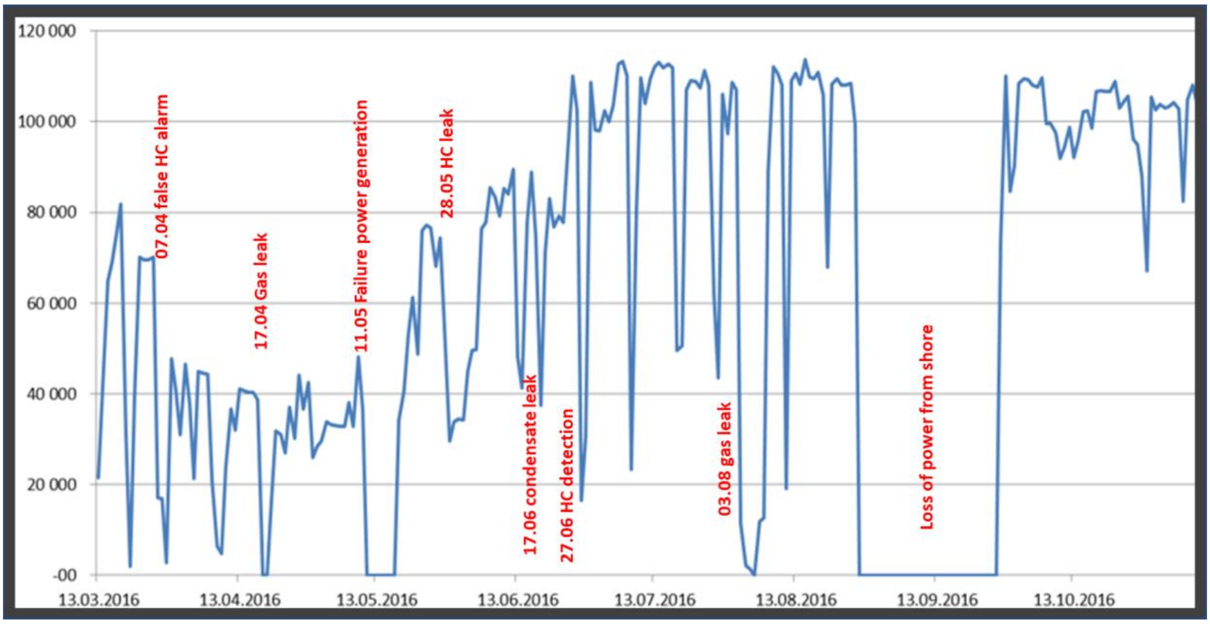


Figure 3-26. Production and production shutdowns from day to day. (Source: Eni)

Figure 3-27 presents capacity utilisation in 2015 in terms of output per month compared with the possible figure in accordance with nominal production capacity. The annual average (calculated from coming on stream) is 61 per cent.

Figure 3-28 presents oil output together with gas and water injection. Injecting water began a little later than production, but progress is otherwise virtually identical.

Among shutdowns largely attributable to the actual production facilities, two incidents involving substantial downtime relate to new concept solutions. These concerned the loss of power from land and damage to the loading hose.

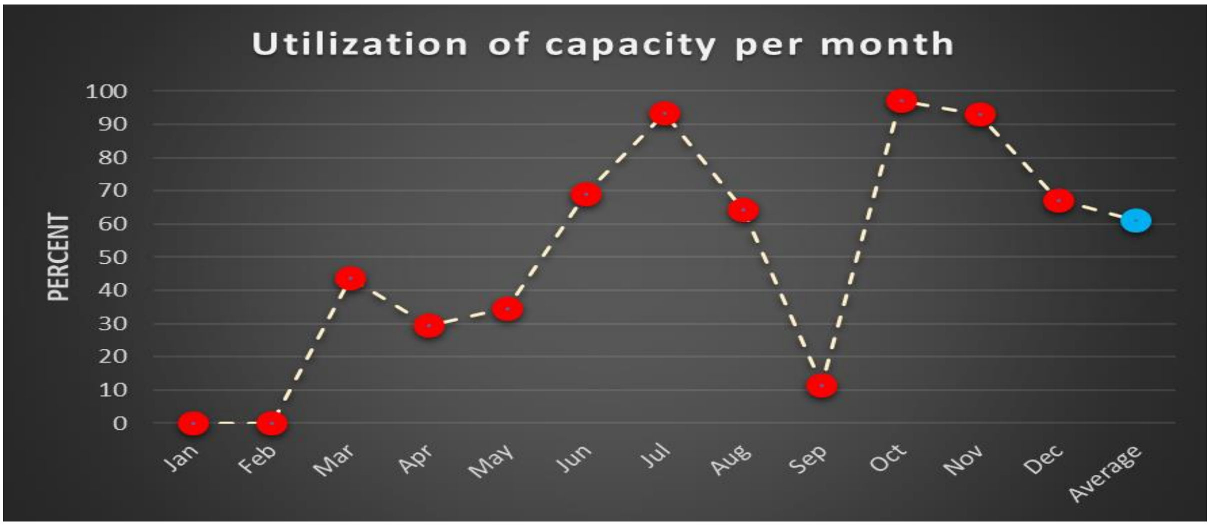


Figure 3-27. Capacity utilisation in 2016. (Source: Acona)

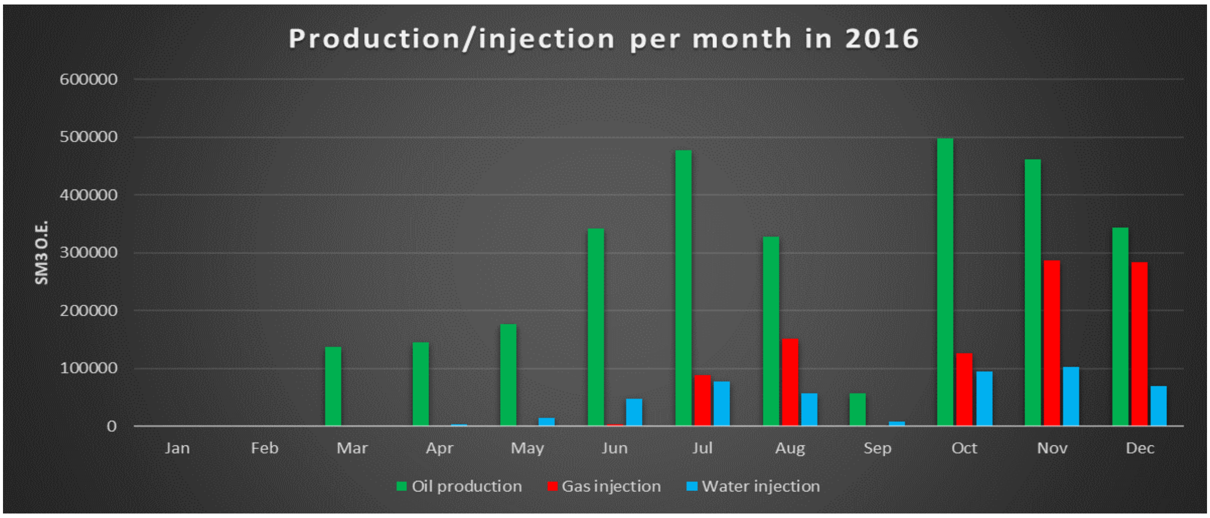


Figure 3-28. Production, gas and water injection. (Source: Acona)

3.7.5 Regularity, HSE and safe operation – wells and subsea installations

Wells, subsea facilities, pipelines, umbilicals and risers have functioned well during the first years on stream. Technical integrity in this part of the Goliat project are well documented through annual inspections and regular testing of safety functions. Daily management of the facilities is conducted in accordance with instructions and procedures drawn up and implemented in an onshore-offshore interaction. Condition monitoring and maintenance planning are performed in accordance with a computerised system developed by Eni Norge. Registering and reporting abnormal incidents comply with the requirements and guidelines which apply for operations on the NCS.

Well integrity: leak requirements set in Norsok D-010 and recommendations in OLF 117 are applied here. Interval requirements accord with those specified in Norsok D-010.

Subsea inspection: inspection is conducted at intervals based on an RBI programme, which is regularly updated on the basis of the actual data.

FPSO structural inspection: umbilicals, riser annulus and subsea flowlines – SSIVs are tested every year.

System monitoring: system status is monitored and registered through a SAP maintenance system and the true advanced collaboration environment (Trace) system. SAP manages maintenance frequencies. Trace acquires live data from many sensors, which are analysed and thereby provide a check of plant condition.

Since start-up, the following have been the only faults or nonconformities with the subsea equipment.

- Downhole gas lift valve in well 7122/7-C-1H – well shut in. Awaiting intervention to replace the valve.
- Fault on one electronic circuit in a subsea control module – well shut down until the control module was replaced.

Subsea inspection, maintenance and repair (IMR) was carried out in 2016, 2017 and 2018. An acid wash job was conducted from a vessel in one of the water injectors during 2016. No heavy well maintenance has so far been done on Goliat.

3.7.6 Status for the project in the second quarter of 2019

Based on interviews conducted, the current position can be described as follows:

- everyone interviewed believes Goliat is now in a stable production condition
- the turning point was the arrival of the last CEO for Eni Norge
- collaborative conditions are now in place
- HSE is now handled in a way which corresponds to other NCS facilities
- the working environment is felt to be good.

The pressure on Eni's management to get on stream as soon as possible (after consent was received) posed a certain safety risk in itself, given that it was impossible to be quite certain at the start-up point that a full overview existed of all outstanding deficiencies.

Furthermore, work still outstanding from the project phase means prioritisation problems exist/could arise between these residual activities, various types of maintenance and the desire for modifications. It is important here that the operator, with the safety organisation, makes good assessments. Furthermore, Equinor's operations expertise in these areas should be drawn on. The PSA should also conduct regular audits here.

As documented by the operator, a number of unfortunate incidents and operational interruptions were experienced in the initial years. None posed a major accident risk. The barriers on the platform functioned as intended, and it was shut down in a prudent manner each time.

3.8 Operator's organisation, partner follow-up and government

3.8.1 Project organisation and manning

In the early phase, the project had an integrated organisation with all functions represented in it. This ensured good collaboration and was a precondition for achieving an optimal concept. Personnel from the partner, Equinor, were also integrated in the project during this period. That made a substantial contribution to experience transfer from other field developments on the NCS. Equinor withdrew its personnel during 2009 and was much less active from then on.

Eni Norge reorganised the project early in the execution phase. Functions such as contracts and procurement, drilling and well, reservoir functions, production preparations and other support functions were stripped out and arranged as services to be delivered from the base organisation. See Figure 3-29. Personnel from these functions attended project meetings, but had only indirect reporting to the project.

From this point, the real project manager was Eni Norge's CEO. This is an unfortunate organisation unless the latter devotes the bulk of their time to the project and is kept updated on all current issues. Such a structure creates "them and us" attitudes and pulverises project responsibility. Disagreements over work processes and solutions to practical problems may often remain unresolved for a long time.

It is also easy to detect from the interviews that substantial cultural differences prevailed between Norwegian employees and head office personnel with regard to how decision processes were conducted, how the workforce was involved and how to work across all functions in an integrated way which contributes to success in the project.

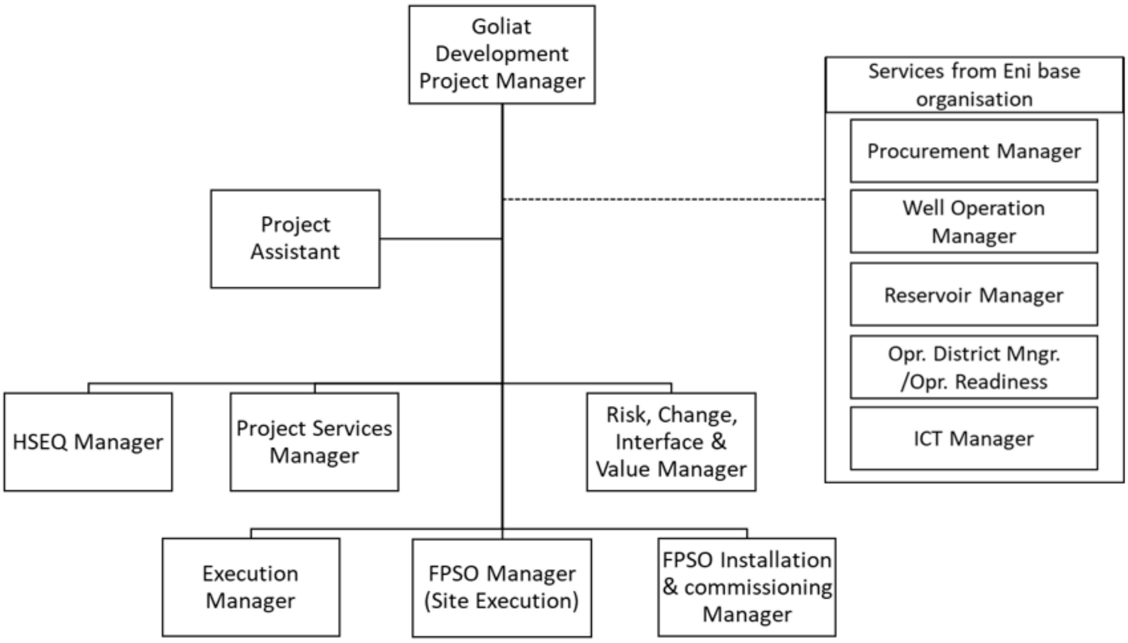


Figure 3-29. Project organisation in the execution phase. (Source: Eni)

Following its restructuring, the project organisation was characterised by the following:

- run centrally by Eni management in Norway/group management in Italy
- the project manager had less responsibility/authority than in comparable projects
- a lack of understanding at head office (Milan) of the Norwegian working environment, legislation and regulations
- a lack of expertise/capacity to manage the EPCI contract
- delayed reporting of problems and cost increases
- frequent replacements of personnel (and management) in the event of problems
- a lack of input from and influence for the future operations organisation.

This way of structuring projects undermines team-building and cross-organisational collaboration. It can also encourage blaming others when something goes wrong.

The project was reorganised for the completion phase in Norway as shown in Figure 3-30.

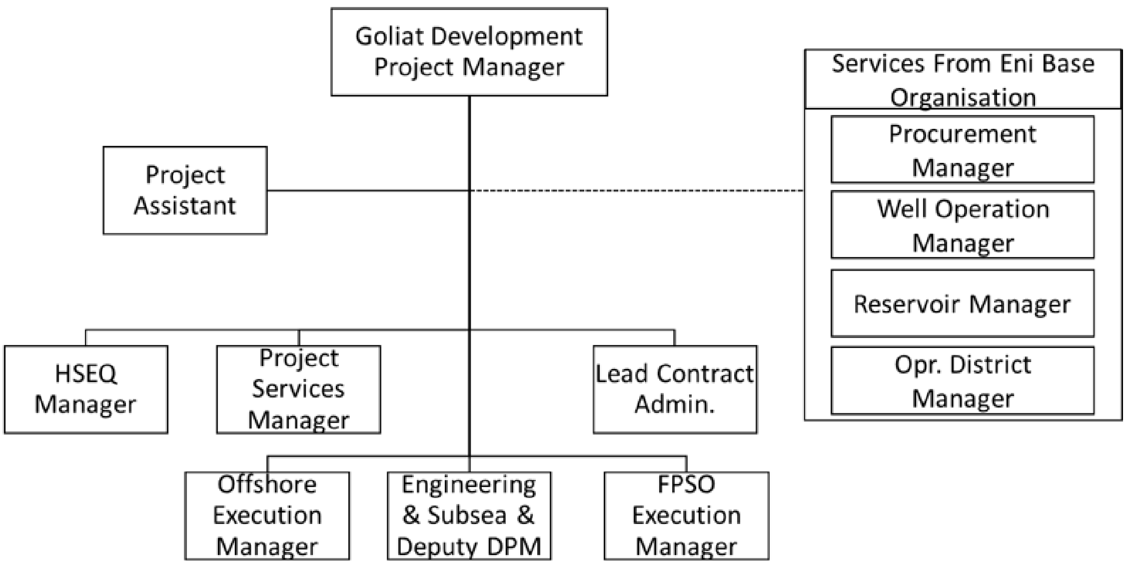
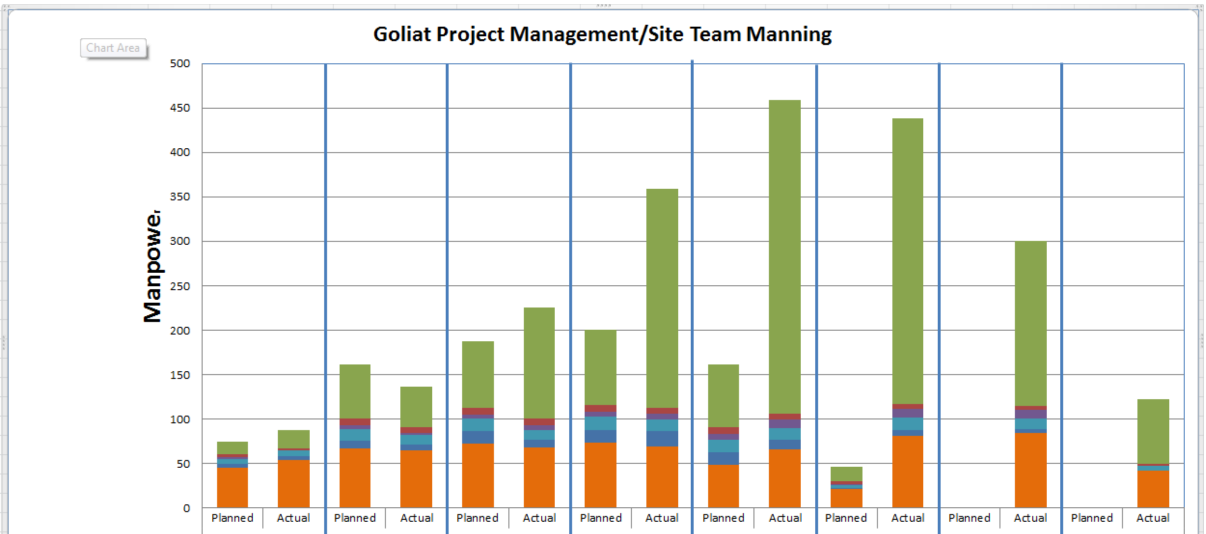


Figure 3-30. Project organisation in the completion phase. (Source: Eni)

The operations organisation was set up late, launching in Stavanger at the end of 2011 and relocating to Finnmark in 2013. A strong desire to recruit as many people as possible locally limited access to personnel with long operational experience of offshore production. More time should undoubtedly have been spent in Stavanger (and not least in the project) with experienced operations personnel who could be phased out gradually after a move to Hammerfest. Figure 3-31 shows how the size of the project team developed.



	Planned 2009	Actual 2009	Planned 2010	Actual 2010	Planned 2011	Actual 2011	Planned 2012	Actual 2012	Planned 2013	Actual 2013	Planned 2014	Actual 2014	Planned 2015	Actual 2015	Planned 2016	Actual 2016
FPSO incl. Offshore Comm.	14	21	60	46	75	125	85	247	70	354	16	321	0	186	0	73
ELE	4	2	8	6	8	7	8	6	8	6	3	5	0	5	0	1
MOI	2	0	4	2	4	6	5	7	6	10	1	10	0	10	0	1
SPS incl . Offsh. Inst. assistant	5	6	13	11	15	11	15	13	14	13	4	13	0	12	0	5
FRI	5	5	9	7	14	9	15	18	15	11	1	7	0	5	0	0
General Mngnt	45	54	67	65	72	68	73	69	48	65	21	81	0	84	0	42

Figure 3-31. Manning overview. (Source: Eni)

3.8.2 Involvement and quality control by Eni's base organisation

The study group has had limited access to conclusions from Eni's own internal quality reviews. Based on the technical material made available, such as choice of concept reports, underlying PDO documents, Feed studies and so forth, neither DG2 nor DG3 should have been approved before significantly more technical work had been done.

3.8.3 Partner's role and involvement

Until DG2, StatoilHydro was an important contributor to the project. It had personnel on loan to and integrated in Eni's project organisation and its own internal group which followed up the project but also did its own independent work. The problems began after passing DG2 in late 2007. At that point, no choice of concept had been made (four remained). The partners (StatoilHydro and Det Norske at that point) rejected DG2 because it was insufficiently mature and involved unrealistic plans and costs. A new attempt to pass DG2 was made in April/May 2008. According to StatoilHydro's technical requirements for quality assurance, the project had still not been matured to a DG2 level, and it stated that this could not be in place until the end of 2008 at the earliest. Technical reviews also made it crystal clear that plans and estimates were unrealistic. The then leadership of StatoilHydro nevertheless chose to approve DG2 in May 2008.

StatoilHydro's acquisition of Det Norske's 15 per cent interest was completed in December 2008. From that point, StatoilHydro had a veto in the licence and could thereby halt all proposals from the operator.

In late 2008, a DG3 proposal was presented by the operator, still with two different platform concepts. At a management meeting on 22 December 2008, StatoilHydro refused to approve DG3 on the basis of its own internal technical review. It wanted more detailed consideration of a number of specific issues. A new and simplified consideration took place, and DG3 for the project with associated PDO submission was approved by management on 6 February 2009.

Given the study group's experience and the project information available at that time, the Goliat project failed to meet the company's own internal requirements for DG3 maturity. Approval must therefore have been based on a formal nonconformity appraisal. Eight months from DG2 to DG3 is also an unusually short time for such a large project, not least because work was being pursued with two concepts in parallel. This would normally take about a year, assuming the DG2 foundation was of good quality.

The PDO was submitted on 18 February 2009 on the basis of a concept choice made in January 2009 and without normal maturation in a genuine Feed study. StatoilHydro added several billion kroner to Eni's estimates in its board decision, and thereby found the economics to be even more marginal than the government could read from the official PDO document.

Several interviewees say that this was because both Eni and StatoilHydro were very keen to have the PDO approved in the spring of 2009, before the general election that autumn and the planned presentation of the management plan for the northern NCS in 2010.

The quality shortcomings created by the urgency of submitting a PDO could have been eliminated if the time had been taken to mature the concept in technical terms before awarding contracts. That would have added a year to the planned start-up (from 2013 to 2014). This was not done. The outcome was a 2016 start-up. StatoilHydro (now Equinor) was the only partner on Goliat. Experience from other projects has shown that this is a difficult position to occupy. A partnership should have at least three members. StatoilHydro (and later Statoil) offered and provided much assistance to Goliat during project execution in such areas as technical standards, procedures and reviews, but could undoubtedly have contributed rather more in the form of good proposals and support for reducing execution risk. Transferring engineering responsibility from CB&I to HHI in Korea, for example, presented a very considerable and wholly unnecessary risk.

When considering whether Goliat was ready to come on stream, the PSA asked Equinor to assess the basis of the operator's start-up decision. In a letter to the PSA of 8 January 2016, Equinor stated that Eni's plan "contains the activities which must be conducted before Goliat can come on stream". It believed the plan was feasible.

Equinor continued on its own initiative by going through the points in the plan to assess whether the Goliat FPSO was ready to start production. Presented on 12 February 2016, the report from this verification concluded that the plan contained the necessary activities, but included the observation that a fairly substantial amount of work remained. This report was used in the pre-start-up risk review conducted by the project and operations organisations and representatives from Equinor.

Conclusions from this meeting were that:

- the platform was completed as far as practically possible for introducing HCs
- all systems were handed over from the project with a signed completion certificate
- ignition source control was largely achieved with some outstanding documentation.

Equinor asked whether outstanding work moved until after start-up was underestimated.

On Friday 11 March 2016, Eni Norge and Equinor confirmed to the PSA that the criteria for bringing Goliat on stream had been met.

3.8.4 Government's role

On the basis of an external and overarching assessment of project risk, a number of conditions already existed in the early phases of the Goliat project which indicated that its execution could face challenges. They included the operator's experience from the NCS in general and the Barents Sea in particular, its organisational structure and manning, an untested FPSO concept, the contract strategy and the choice of main contractor. These conditions were taken into account when the PSA shaped its strategy for following up the Goliat project.

The PSA devoted attention to all these conditions through a number of audits during the engineering and fabrication phases. Several of these were purely for follow-up – in other words, checking on nonconformities and improvement points identified in earlier audits.

The PSA conducts such follow-ups if it fails to receive satisfactory feedback from the operator concerning the resolution of nonconformities and improvement points. A more detailed review of the audit reports for Goliat shows that certain conditions were classified as nonconformities in the first audit and then as improvement points in follow-up audits. The PSA downgrades the level of seriousness in this way if progress can be demonstrated since the previous audit but the condition has still not been resolved in a completely satisfactory way, and where no application has yet been received to bring the facility on stream. If the identified condition has not been satisfactorily resolved when the start-up application is submitted, the PSA will again classify it as nonconformity and, if necessary, make an order. Several examples of this can be found in the PSA's follow-up of Goliat.

From the start of the PSA's formal supervision of the Goliat development in 2008 to the present day, a total of 25 audits have been conducted. They extend across the concept/ project preparation, post-PDO engineering and fabrication, completion/readying for operation and production phases. Eight have been carried out in the production phase – in other words, from 2017 until today. One of these was directed at the role of Statoil (now Equinor) as licensee. This means that Goliat, and particularly its FPSO part, has been subject to rather more audits than the two other projects covered in this study, but that can again be explained by the fact that engineering and fabrication for the Goliat FPSO took far longer than originally planned.

What the publicly available documentation does not reveal about the PSA's supervision of Eni and Goliat is the considerable commitment made in the form of guidance to Eni's personnel during the execution phase as well as support for training Eni's contractors in understanding the regulations, using standards and so forth. The substantial scale of this commitment has been confirmed by interviews with both Eni and PSA representatives.

The PSA conducted five audits of Eni while consent was under consideration (from 15 February 2015 to 19 January 2016). During this period, it also received seven unique whistleblowing reports concerning various conditions on Goliat. Findings in the audits conducted indicated that problems persisted in two areas in particular: logistics and barriers (including electrics/ignition source control). The PSA also asked Equinor to give its assessment of the basis for the operator's decision to bring Goliat on stream. In a letter to the PSA of 8 January 2016, Equinor stated that Eni's plan "contains the activities which must be conducted before Goliat can come on stream". It believed the plan was feasible.

After approval of a PDO, the government assumes that the licensees develop the field within the parameters specified in that document. The NPD also supervises project progress in the construction phase, but not as closely as in the early and production stages. It is difficult to see that the NPD has had any role in or influence on the actual development of Goliat between DG3 and DG4.

When reading the comments on Goliat in the government Finance Bill between 2012 and 2016 (see appendix B), it is clear that the MPE was also less than fully briefed about what the real problems were on Goliat.

3.9 Overall assessments

3.9.1 The project's preconditions and parameters

The starting point for the Goliat project was:

- limited reservoir complexity and uncertainty
- medium-sized project in terms of capacity and platform facilities
- uncomplicated production facility
- basically marginal profitability
- opportunities for increased activity through continued exploration in the area
- uncertainty about Barents Sea conditions and demands
- strong pressure from external stakeholders
- long way from infrastructure
- substantially larger Sevan facility than previously built

- moderate technological qualification
- operator without NCS experience
- EPCI strategy which ends up with execution in Korea
- over-optimistic planning and budgeting in the PDO.

3.9.2 FPSO concept maturation and execution

The selection of a circular FPSO was a good and robust choice of concept. What went wrong was execution. The following assessments have been made from an execution perspective.

- Systematic studies were made of relevant concepts to the end of 2007 (in other words, in 2006-07). The assessments made and conclusions drawn appear to accord with good practice.
- The project passed a milestone at the end of 2007 which was referred to as DG2, but which failed in reality to reflect that status. At DG2, a choice of concept should have been made and the concept matured to the start of Feed studies. A design competition held in 2008 was supposed to be to "Feed level" (but in reality did not reflect a normal Feed level). An official choice of concept was made in January 2009 on the basis of this work.
- The PDO was submitted on 28 February 2009, and this date is also referred to as DG3. Instead, a new and complete Feed should have been initiated up to the autumn of 2009, followed by an ITT at the end of 2009. The loss of time would have been about six months in relation to the path taken.
- Thanks to the hasty decisions, a weak Feed formed the basis for fairly substantial underestimating, which was only partly corrected through the post-Feed study. Underestimating weights led to problems with engineering and to cost increases.
- The constellation of HHI/CB&I with assistance from Sevan was a risk which the project should have got to grips with immediately in order to ensure execution of the EPCI contract in accordance with schedule, costs and quality.
- Given the status of the project in 2010, the overall plan should have been revised and the production start delayed by at least a year. The study group cannot see detailed planning and risk assessments with associated understanding of consequences. Nor was attention paid by management (at either project or company level) to preventive measures and actions.
- Weight developments following HHI's takeover of the engineering show that estimated weights from the early phase were unrealistic and that the whole basis for construction was insufficiently mature. For its part, HHI was conservative in its estimates and little concerned to keep weights down. Simpler design and construction were given priority ahead of weight optimisation.
- HHI had taken on far too much work during this period. That resulted in extensive hiring of labour which was to some extent unqualified, leading in turn to poor productivity and delays in executing all ongoing projects. As one of the smaller projects, it was difficult for Goliat to secure priority.
- From 2010 until 2017-18, the topsides part of the project was more or less out of control.
- Quality control and documentation of work done on the topsides must be characterised as very deficient and, on certain points, directly misleading.
- The Sevan concept is not particularly construction-friendly, and not enough construction studies were conducted in advance to identify the best possible solution. HHI opted for a method where simple design and fabrication were given priority over weight-optimal solutions. The large number of topsides sections hooked up on board led to a massive accumulation of work on the actual platform.

Conclusion: a successful/robust technical concept with weak execution.

3.9.3 *Extract from Eni's report on its experience*

The following extract from Eni's report on its experience supports the study group's findings:

Project Management and Execution Strategy ▪ Heavy company organisation ▪ Lack of coordination and ownership / accountability in all areas and in internal/external interface management ▪ Engineering, Operation, Compliance not involved at all stages and with no integrated view	▪ Complicated decision path ▪ Big number of parallel open issues ▪ Necessity to intervene on project organisation defining a lean and delivery-oriented site organization, with injection of skilled personnel ▪ Necessity to set up of a HQ 'Senior Advisory Committee' to overcome execution challenges in strategic projects
FEED and Tendering ▪ Change in FEED strategy from competitive to single Contractor FEED ▪ FEED completion after contract award	▪ Multiple project changes, caused also by low FEED quality ▪ Extended overlap of detailed design and construction with consequent reworks
Detailed Design, Supply and Interface Mgmt ▪ Three different not integrated Company engineering teams ▪ Messy approval cycle from Company side ▪ Not correct use of 3D modeling as a design tool ▪ Poor focus on changes minimisation ▪ Excessive number of third parties involved	▪ Lack of single point accountability (engineering integration was increased with centre of gravity at FPSO site) ▪ Multiple comments with delays in engineering and construction reworks ▪ Reworks (piping) also due to improper use of 3D modeling ▪ Late close out of project issues
Construction & Commissioning ○ CCMS with not clear accountability and 'free' access to the system for MC and punch lists Company ○ Heavy QC site organization with the duty to approve all quality documents and work steps ○ No clear handover procedure MC → Commissioning → Operation	▪ CCMS not fuly populated in line with work progress ▪ Poor control on the degree of project completion ▪ Delays in commissioning and hand over

Figure 3-32. Extract from Eni's report on its experience. (Source: Eni)

3.10 Learning points

Layout. The negative experiences with the Goliat platform relate virtually entirely to the Sevan design and the topsides. The solutions adopted were little developed and did not reflect the radial hull structure. With hindsight, a clearer division should have been adopted between hull and topsides. The support structures for the latter should have had an orthogonal design tailored to a facility featuring large rectangular modules organised on the basis of an area division, in accordance with established practice. Furthermore, these big modules could have been installed through a combination of lifting and skidding.

The comment on a clearer distinction between hull and topsides also applies to the pump room and manned areas in the hull. The pump room could have been replaced by submerged pumps, and avoiding manned spaces in the hull would have meant a considerable simplification by eliminating the safety challenges posed by an enclosed pump room in the hull.

Topsides height. It also became clear at an early stage that the topsides height was too low and that equipment density/space utilisation was unacceptable with regard to construction, safety, operation and maintenance. All this reflected the lack of quality and prioritisation in the Feed phase, rather than the concept itself.

Technical maturation. The maturity of the project was far too low at both DG2 and DG3. This is absolutely the most important underlying cause of the problems which arose during project execution. Not only the operator, but also the partner and the regulatory authorities should have seen this. It should in any event have been identified when considering the PDO.

Control/verification of quality in the early phase.

What should have been done?

- Carried out third-party or other independent verifications (partner) of the content in the final delivery of documentation for the choice of concept before the decision was taken.

- At the end of the concept phase, excluded the options seen to be commercially unacceptable and defined a post-concept scope of work for the remaining solutions in order to secure adequate knowledge of a single choice for taking forward to Feed.
- Where D&W activities are concerned, the government should have been challenged at an earlier stage over using oil-based mud. Drilling efficiency, measured in metres per day, was doubled.

Worker participation. Eni's organisation fell short in the involvement of the workforce (future operations personnel and the safety service), and did not fulfil the intentions in the legislation until the final phase offshore. Furthermore, the project organisation does not appear to have been able to take the necessary measures in time to close identified gaps in relation to the regulations.

Development of own organisation and expertise. Clearer expertise requirements should have been defined from the start, with genuine qualification for key posts, and own employees should have held key positions (limit use of consultants). The project's mandate, organisation and responsibility should have been clarified early and with more overall responsibility for the project management. Furthermore, the operator should have strengthened its own internal control function.

Contract strategy and format. Changes along the way from concept competition to competitive tendering based on a design basis led to a technical foundation which was far too poorly developed for a genuine EPCI contract. Clearer requirements should have been set by the operator for the contractual relationship between HHI and its engineering subcontractor. Changing engineering responsibility eight months into the contract was very unfortunate.

Change of engineering responsibility. Changing responsibility for engineering so soon after the EPCI contract kicked off was very unfortunate. If a change was absolutely necessary, it should have been to another competent international player. Transferring engineering responsibility to HHI proved a very unfortunate decision which made a strong contribution to the problems experienced subsequently.

Project planning. Project kick-off should have delayed by a year at an early stage. That could have produced a project basis and level of maturity which would have allowed controlled execution.

Good and realistic schedules with an in-depth understanding of relationships across the project and between different contracts are crucial for success. Possible problems (time, cost and quality) must be identified as soon as possible and reported immediately to both own management and the partnership.

Training contractors and subcontractors. The project should have ensured that contractors conducted adequate training of their whole workforce and all contract personnel with the desired HSE and quality standards (Norsok and so forth).

Risk management. It is essential that early identification of possible risk, establishment of preventive action plans, and genuine risk management and follow-up are part of the daily agenda at all levels.

Relationship between project and future operations organisation. The principles of the operations philosophy must be in place at DG2. Production preparations and organising for safe work processes and procedures must begin as early as possible in a detailed dialogue with those shaping the technical solutions. The division of responsibility between project and operations must be crystal-clear from mechanical completion of the first system until all the systems have been handed over to operations. Requirements for completion at handover of responsibility must be established and never deviated from if this represents a safety risk.

4 Aasta Hansteen

4.1 Overall project description

4.1.1 Location and reservoir description

Aasta Hansteen lies in the northern Norwegian Sea, 140 kilometres north of Norne and 300 kilometres west of Bodø. It is thereby relatively far from land and existing infrastructure. The water depth in the area is about 1 300 metres.

This field originally embrace the Luva (1997), Haklang and Snefrid South (both 1998) discoveries. A new discovery, Snefrid North, was made in the area in 2015 and is now being tied back to Aasta Hansteen. Total reserves for Aasta Hansteen and Snefrid North are estimated at 55.6 billion scm of gas and 0.6 million scm condensate, corresponding to 353 million bbl oe.

Aasta Hansteen was proven in 1997 by BP. The operatorship was transferred to Statoil in 2006, with the PDO approved in 2013.

Figure 4-1 provides an overview of the Aasta Hansteen field.

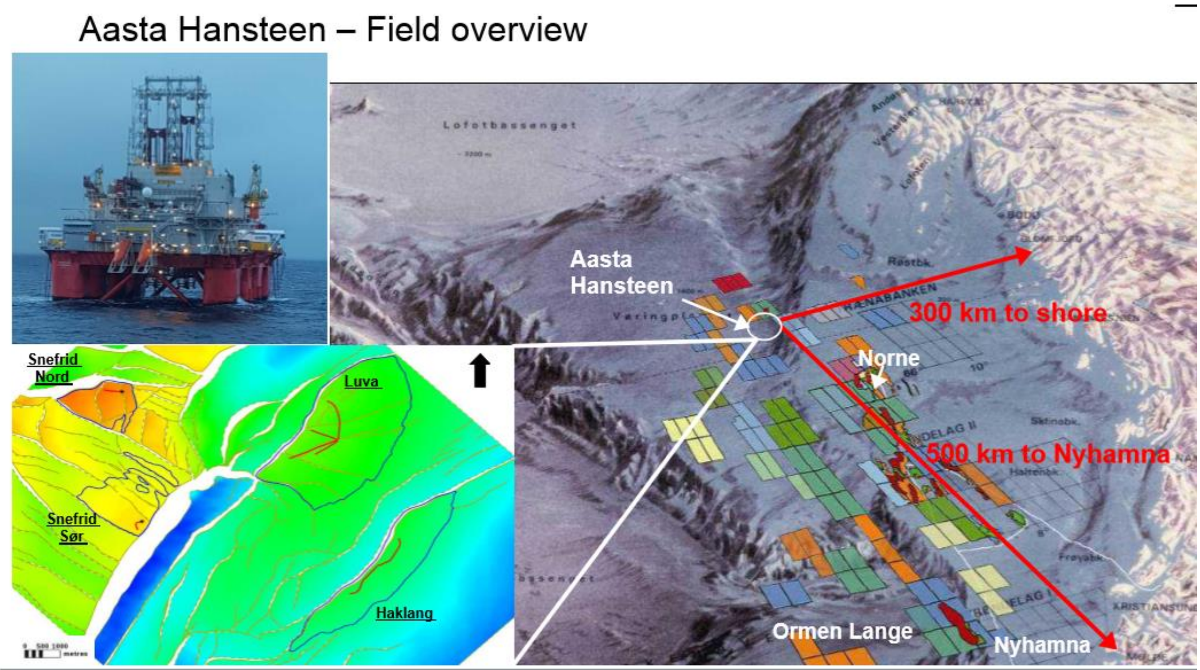


Figure 4-1. Overview of the field. (Source: Equinor)

4.1.2 Licence history and project description

PL 218 was awarded in 1996 through the 15th licensing round. Licensees then were BP, Statoil, Esso and Saga Petroleum. Saga sold its holding to Conoco on 29 September 2000. Statoil took over BP's interest and the operatorship in 1 January 2006. PL 218B was awarded in 2011 on the basis of the expected extent of the Haklang structure and the additional acreage needed for positioning the Aasta Hansteen platform.

The initial wildcat on the Luva segment was drilled in 1997. Two exploration wells on Haklang and one on Snefrid South were drilled in 2008. All these wells proved HCs in the form of gas with marginal quantities of liquid.

Equinor is the operator with 51 per cent. Its partners currently comprise Wintershall (24 per cent), OMV (15 per cent) and ConocoPhillips (10 per cent).

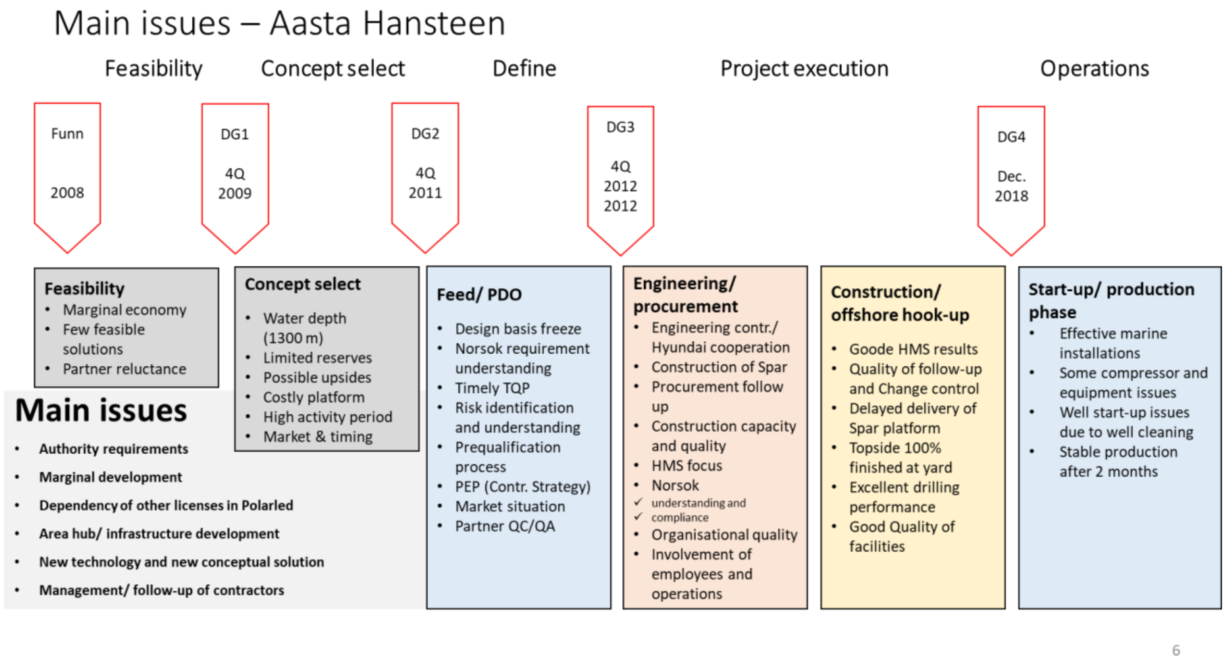


Figure 4-2. Milestones and main issues. (Source: Acona)

The gas field has been developed with three subsea templates producing to a floating Spar platform with a cylindrical hull moored to the seabed. The templates are tied back with flowlines and steel catenary risers (SCRs). This platform is the first Spar on the NCS and the largest of its kind in the world. It also ranks as the world's first with integrated storage tanks for condensate. Snefrid North is being developed with a template tied back to the Aasta Hansteen field. Plans call for it to come on stream in late 2019.

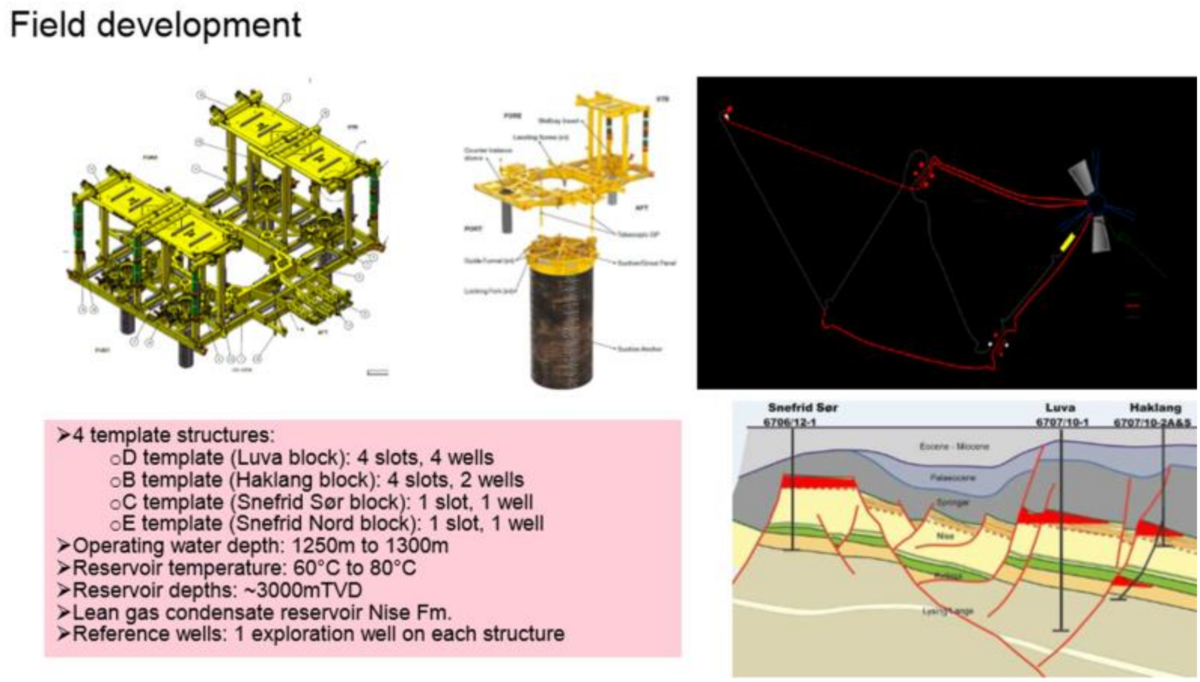


Figure 4-3. Field development concept. (Source: Equinor)

The 70 000-tonne platform was towed to the field in April 2018 and came on stream on 16 December 2018. Gas is transported in the Polarled pipeline to the Nyhamna terminal for export to the UK. Produced condensate is loaded into tankers and shipped to market. Aasta Hansteen and Snefrid North are expected to produce about 23 million scm of gas per day at plateau.

Polarled is a new 482-kilometre gas pipeline from Aasta Hansteen to Nyhamna in Møre og Romsdal county. Its PIO was submitted and approved at the same time as the Aasta Hansteen PDO in 2013. Completed in 2015, the pipeline provides a gas export solution for Aasta Hansteen and for other Norwegian Sea fields. The project also included an expansion of the Gassco-operated facility at Nyhamna. Polarled is tailored for the connection of existing and future discoveries in the area. See Figure 4-4.

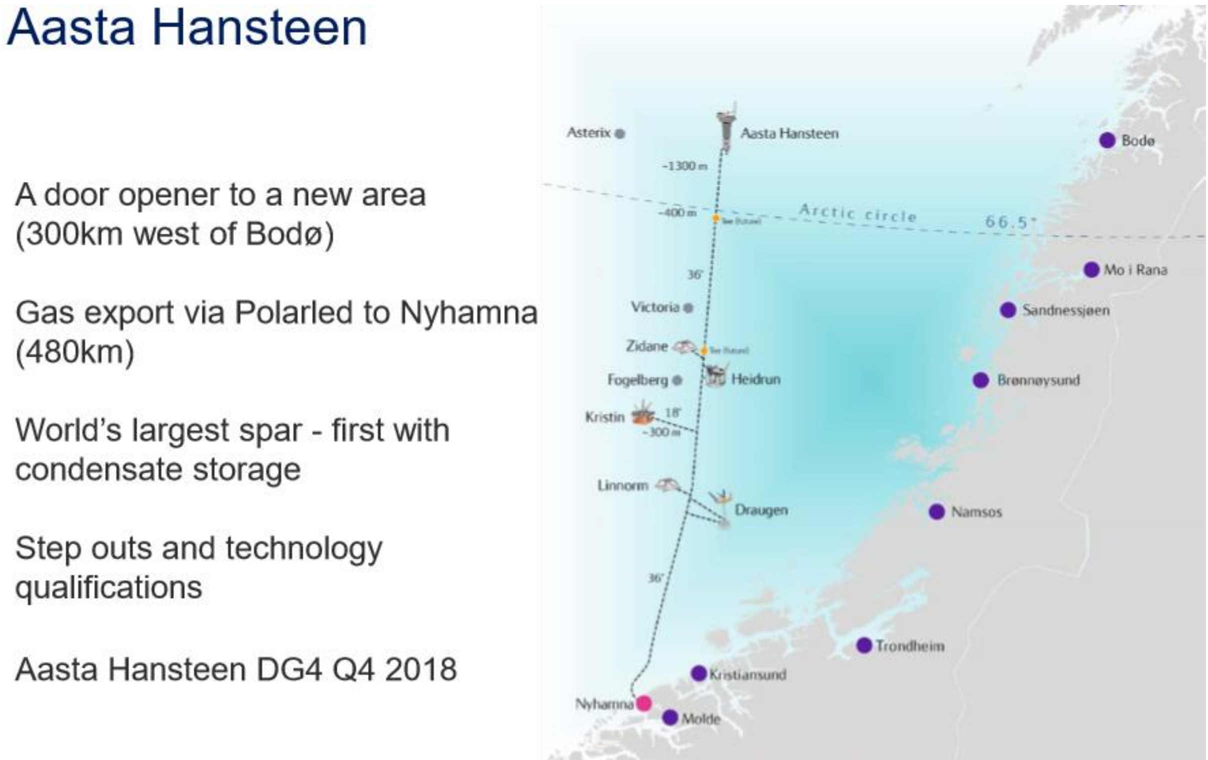


Figure 4-4. Area infrastructure. (Source: Equinor)

The Aasta Hansteen field is operated from Harstad by Equinor's operations organisation in northern Norway. Its supply base is at Sandnessjøen, with the heliport at Brønnøysund.

4.1.3 Development of plans and costs over the life of the project

An overview of early-phase milestones and activities is presented in Figure 4-5 and Figure 4-6.

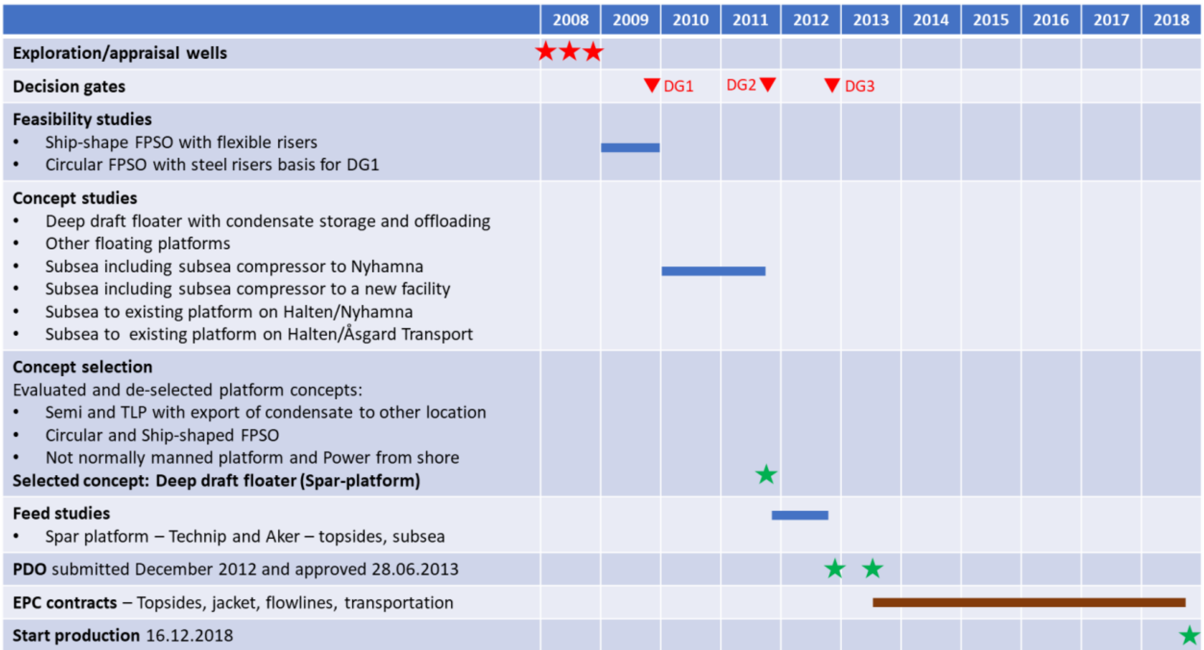


Figure 4-5. Activities and milestones in the early phase for Aasta Hansteen. (Source: Acona)

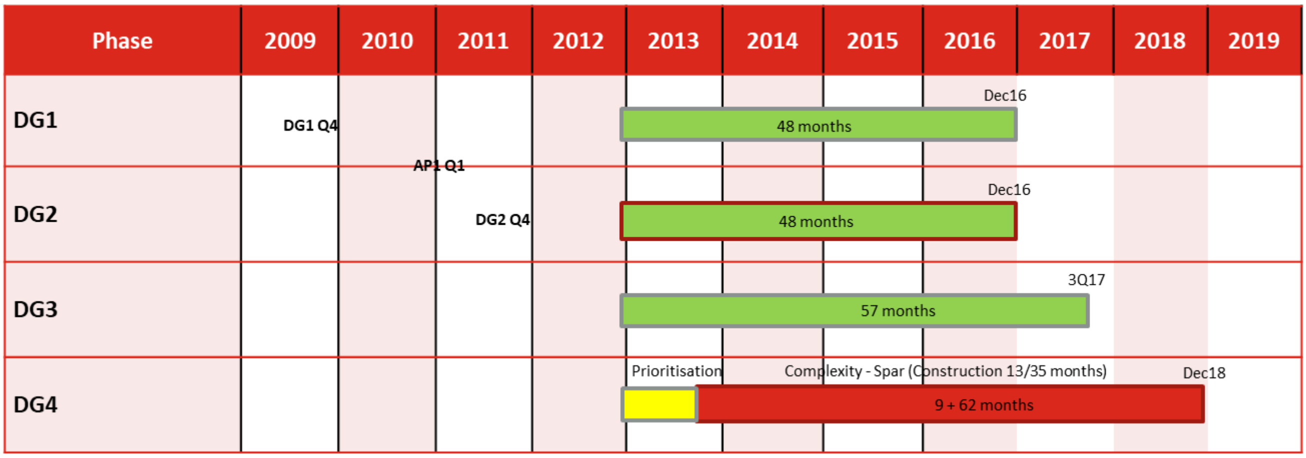
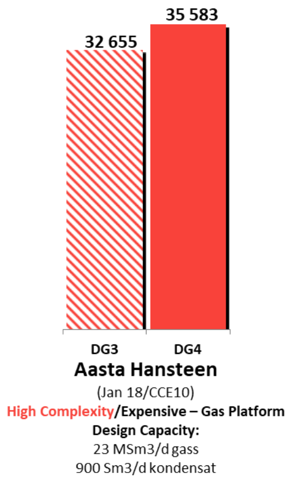


Figure 4-6. Execution –plan development. (Source: Acona)

Figure 4-7 gives an overview of the most important cost elements at DG3 and DG4. Figure 4-8 and Figure 4-9 provide a graphical presentation of changes over time for each main element in the estimate.



MNOK

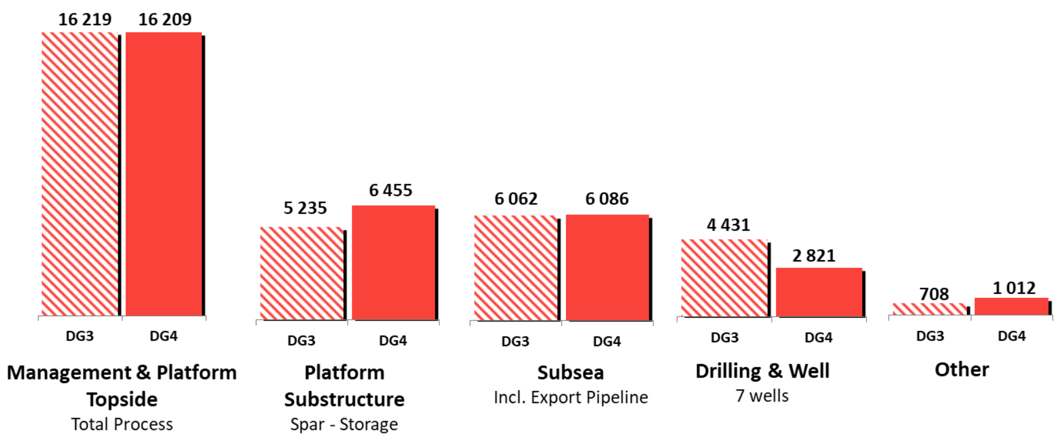
	DG3	DG4	DIFF
Management	3 171	2 673	
FPSO	-	-	
Topside	9 881	13 298	+ 34%
Living Quarter	-	-	
Completion	-	-	
Substructure	5 235	6 455	+ 23%
Mooring,Offloading & Inst.	-	-	
Risers & Flowlines	-	-	
Heavy Lift and Transport.	-	-	
Extend./Remaining Scope	-	-	
Contingency	3 167	238	
Facilities – Platform	**21 454**	**22 664**	**+ 5%**
Facilities – Subsea & Pip.	6 062	6 086	
Drilling & Well	**4 431**	**2 821**	
Power Supply incl. Infra.	-	-	
Host	-	-	
PMT/Petek	201	321	
Preparation for Operation	-	291	
Insurance	507	400	
Adjust. (Currency impact)	-	3 000	
Phase 1	32 655	35 583	
Phase 2			
Total – Project Close-Out	**32 655**	**35 583**	**Jan 18**
Total – RNB 2019	34 600	37 500	MNOK'18

DG3 - Total Dry weight 23 743 tonnes

DG4 - Total Dry weight – 24 370 tonnes

Figure 4-7. Capex – cost development. (Source: Acona)

MNOK



DG3 – Total Dry weight 23 743 tonnes (683 NOK/KG).

DG4 – Total Dry weight 24 370 tonnes (665 NOK/KG **excl. Currency Impact**).

Figure 4-8. Main elements – cost development. (Source: Acona)

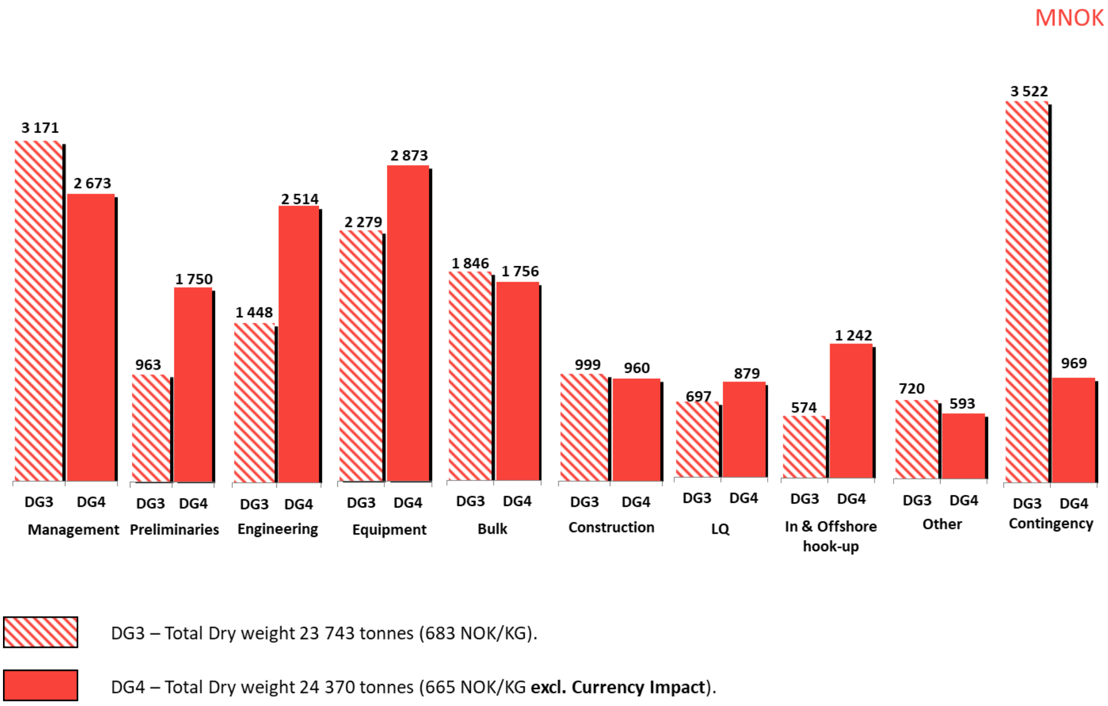


Figure 4-9. Management and topsides – cost development. (Source: Acona)

The project initially failed to secure priority at the yard, while the scope and complexity of work on the Spar hull increased. Execution time for the project thereby became particularly lengthy. That helped to increase costs, with the bill for the Spar hull rising by NOK 1.2 billion. "Preliminaries" in the HHI contract climbed by NOK 0.8 billion. HHI's productivity was poor, and it was only compensated for about a third of the construction costs. It thereby suffered a substantial loss.

The overall cost estimate was virtually unchanged from the project's close-out report, amounting to NOK 32.7 billion at DG3 and NOK 32.6 billion at DG4. On the other hand, execution time increased from 57 months at DG3 to 72 at DG4.

Other parts of the project, such as drilling and well completion, did much better, with cost savings of NOK 1.6 billion. That reflected a rig rate of USD 275 000/d and a "world class" drilling speed. The subsea installations were manufactured and installed on budget and to the (revised) schedule.

The scope of work on the topsides was stable, and rose from 23 743 tonnes at DG3 to 24 370 tonnes at DG4 – in other words, a weight increase of just two-three per cent.

Engineering costs were estimated at NOK 1.4 billion on contract award and rose to NOK 2.5 billion at DG4. The normal hourly rate for engineering design is USD 115, and productivity of 105 hours/tonne is fairly similar worldwide.

Fabrication estimates for the topsides came to 10 million hours, while fabrication hours for the Spar hull were estimated at 2.5 million on contract award and ended up as 10 million. Hourly rates and productivity for fabrication/installation vary widely around the world.

Experience shows that hourly rates in the Far East are about 40 per cent (USD 45) below the Norwegian level, which is USD 115. Of this, USD 75 is direct and USD 40 indirect. Productivity in the Far East (350 hours/tonne) is expected to be half the level of Norwegian yards (175 hours/tonne). The strategy behind placing the contract in the Far East was to achieve a fabrication/installation saving of about 30 per cent, but this gain was quickly swallowed up by a tripling in the operator's management/follow-up costs and a significantly longer execution plan.

Completion costs were underestimated and rose from NOK 0.,6 billion at DG3 to NOK 1.3 billion at DG4. Total costs for the topsides, including operator management/follow-up, were stable and came to NOK 16.2 billion at both DG3 and DG4. The kilogram price was relatively constant/favourable and fell from NOK 683 to NOK 665.

Experience shows that completion of simpler platforms offshore takes six months. Aasta Hansteen required eight, which could reflect the project's complexity/new solution.

The project's internal rate of return failed to satisfy the company's requirement. But considerable emphasis was given to the project's upside through establishing an area centre which permits the realisation of additional smaller discoveries in the vicinity.

A big differential exists today between the oil price of USD 90/bbl assumed in the plan and the current level of just over USD 60/bbl. The economics of the project have been hit by an extended execution time and the loss of volumes in Polarled from other licences. On the other hand, an increase in the recoverable volume has had a positive effect. Future oil/gas prices and new commercial discoveries in the area will affect the final profitability assessment.

4.2 From licence award to choice of concept (DG2)

4.2.1 Feasibility studies and DG1 in the period up to 2011

The first feasibility studies were conducted on the basis of subsea wells and a conventional ship-shaped FPSO. It became clear at an early stage that the risers (based on flexible pipelines) would be expensive because of the 1 300 metres in water depth.

Assessments were thereby made of alternative platform concepts which could be combined with steel risers. Such a combination is only possible if the platform has very good motion properties. The most relevant solution was a Spar. Platforms of this kind with catenary risers are used today in water depths down to 3 000 metres in the Gulf of Mexico. However, they lack oil/condensate storage when used as a production platform. The very first Spar, in fact, was a pure storage facility – Brent Spar from 1976.)

It was then decided to base the DG1 decision on a circular FPSO similar to the Goliat unit, but with SCRs. This solution was considered feasible, but model tests indicated that platform motion posed a substantial risk to the risers.

4.2.2 Concept studies – evaluation phase up to DG2

Challenges on the field involve a mix of great water depth, long distance from land and other infrastructure, and tough weather conditions. The combination of currents and waves is particularly significant for the platform hull and risers. A broad range of development solutions were assessed from early 2010. See Figure 4-10.

1) Floating platform with deep draught, condensate storage and rich gas export to Nyhamna.
2) Other floating platforms with little or moderate draught, condensate storage and rich gas export to Nyhamna.
3) Subsea wells with seabed compression and wellstream transfer to Nyhamna.
4) Subsea wells with seabed compression and wellstream transfer to a new land facility, with rich gas piped on to Nyhamna.
5) Subsea wells with wellstream transfer to existing platform in the Halten area and rich gas piped on to Nyhamna.
6) Subsea wells with wellstream transfer to an existing platform in the Halten area and rich gas exported via Åsgard Transport.

Option 2 was eliminated because its economics were poorer than option 1. Nor were there any identifiable upside opportunities.

Options 3, 4 and 5 were also dropped because their economics were poorer than option 1, along with major technological challenges and lower robustness to reservoir uncertainty.

Option 6 also faced the problem that Åsgard Transport lacked capacity.

First and foremost because of the economics, it was decided to continue with a stand-alone development based on a deep-draught platform

The other options assessed under option 2 were:

- a circular FPSO
- a ship-shaped FPSO
- a semi-submersible platform
- a tension-leg platform (TLP).

Both FPSO options were dropped because of higher costs, related primarily to the flexible risers now regarded as a requirement with these concepts. The big condensate storage capacity they would automatically have provided was seen as unnecessary and no benefit.

A deep-draught semi or a TLP has good motion properties and the potential to use steel risers, but fails to satisfy the condensate storage requirement. See below.

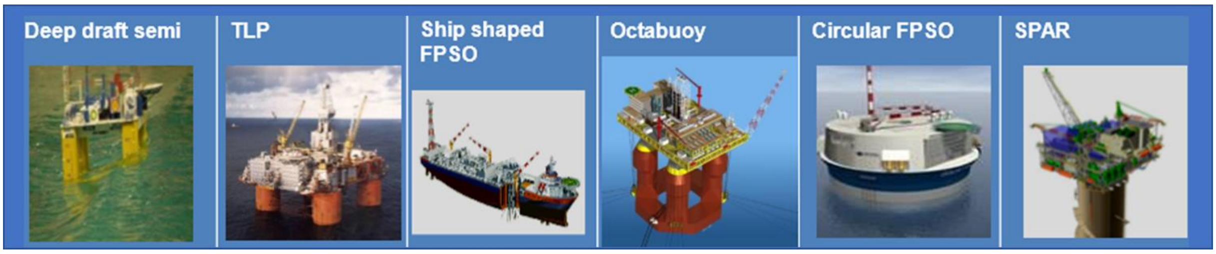


Figure 4-10. Platform concepts assessed. (Source: Equinor)

A normally unmanned platform was also considered, but rejected because of the complexity of its topsides.

Power from shore was included as a condition from early in the study phase, but it soon became clear that this would be far too costly and technically complex (cable 320 kilometres long and great water depth).

It was important to find an acceptable solution for Aasta Hansteen's small condensate output. The preferred answer was offshore loading from a small condensate store integrated in the platform hull. Solutions which required a separate storage ship were eliminated. Nor was a good solution found for a condensate pipeline to another platform or land.

Injecting the condensate back below ground was considered unacceptable by the government from a resource management perspective.

Adding the condensate to the export gas in Polarled was unacceptable to the owners of Polarled/Nyhamna, since this export pipeline is tailored for the tie-in of existing and future discoveries in the area.

4.2.3 Choice of concept and DG2 – November 2011

Based on the concept studies conducted in 2010-11, a choice of concept was made in November 2011. The development concept is a floating Spar-type production facility with built-in condensate storage and subsea installations. The Spar unit comprises a circular hull measuring 97 metres long, which is extended by a truss structure with a ballast tank at the keel, 180 metres below sea level. The truss section with horizontal heave plates and the ballast tank help to dampen motions and to provide good stability.

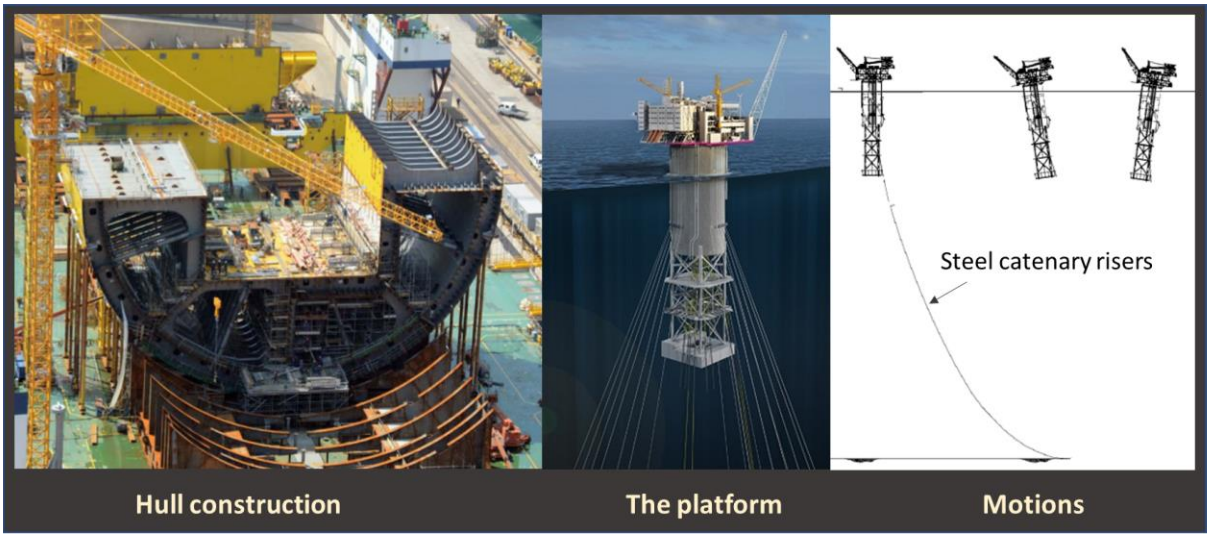


Figure 4-11. The Aasta Hansteen platform. (Source: Acona)

Held in place by 17 mooring lines, the platform has entry points for risers in the centre of the hull and the concept offers good properties in terms of stability and dynamic response to wind, waves and currents.

The topsides measures 100 x 50 metres and are built as an integrated structure with living quarters, process and utilities. They were mated with the hull before towout to the field.

This is the first development on the NCS to be based on a Spar, but the concept is known from other countries. The Aasta Hansteen platform is by far the largest Spar in the world to date. Unlike earlier units of this type, it has an integrated condensate store with a capacity of 25 000 cubic metres. This has affected its size and complexity.

4.2.4 Assessment of technical safety in concepts studied

The Aasta Hansteen hull is a Spar unit split into three sections. See Figure 4-12. Its topmost section is a circular cylinder with a diameter of 50 metres and height of 98 metres, incorporating condensate storage. The lowest section is a 10-metre-high rectangular tank for solid ballast, while the central section is a truss structure. Standing 198 metres high overall, the hull weighs 46 000 tonnes.

It is moored with 17 taut lines and can pull 12 risers and four umbilicals into the centre of the cylinder.

Developing Aasta Hansteen depended on technology qualification in a number of areas – not necessarily new technology, but new applications of existing solutions. This related to such areas as the actual Spar concept, the polyester mooring system, the steel risers, the well maintenance system and SSIVs.

Power and heat are needed on the field for process and supporting facilities, the export compressor and the living quarters. The facility has a maximum electricity requirement of 56MW. Local power generation using gas turbines was selected. One turbine generates electricity and another drives the export compressor, which will recover heat to meet requirements in the process and the living quarters.

Measuring 100 x 50 metres, the topsides have three deck levels. Their dry weight is 23 000 tonnes and the maximum permitted operational weight is 31 500 tonnes. The topsides rest on four points at the top of the hull. Three production risers and one for export are conducted through pull-in tubes in the centre shaft to deck level. Additional capacity is provided for seven production risers, one export riser and one umbilical.

The platform is divided into four main areas: process with flare boom, utilities, living quarters and hull. The hull accommodates storage for condensate and fresh water as well as various systems.

Incorporating living quarters, process and utilities, the topsides are built as an integrated structure and were mated with the hull before towout to the field.

The process plant has been designed in accordance with established requirements and standards related to preventing accidents or hindering their escalation.

Extensive model tests and calculations showed that the platform would have good motion properties, which was of great significance for the choice of concept.

The risers are the SCR type, which are pulled in through guide tubes protected within the main structure itself and terminated on the topsides cellar deck.

Stabilised condensate is stored in four tanks in the hull, located beneath the zone exposed to possible ship collisions. A carpet of HC gas minimises vaporisation of VOCs from the store. Condensate is pumped to shuttle tankers with submerged pumps. The basic principle is that all HC systems will terminate on the process side of the topsides cellar deck. A 12-inch loading hose is used, with loading taking place about once a month.

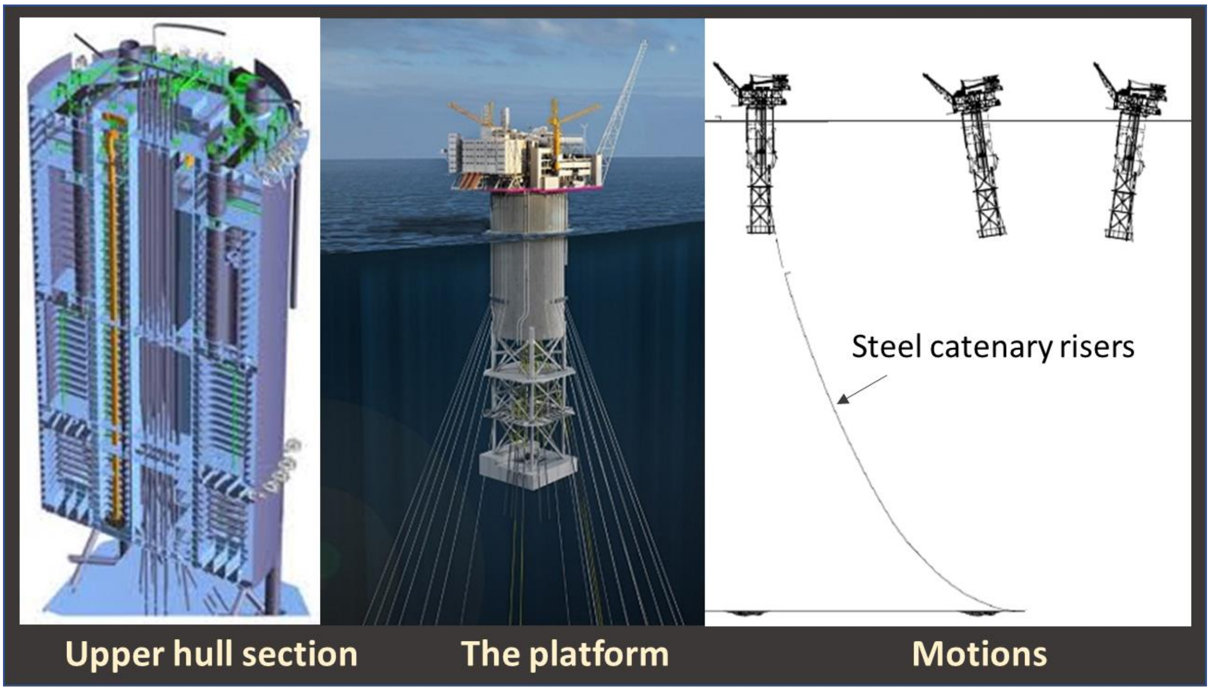


Figure 4-12. Illustration of the Spar platform. (Source: Acona)

Aasta Hansteen lies in the northern Norwegian Sea, a long way from land and existing infrastructure. The water depth in the area is about 1 300 metres, and the combination of wind, wave and ocean currents is among the most extreme on the NCS. This meant that the field basically represented an unusually demanding development.

This part of the Norwegian Sea, then known as the Vøring Plateau, attracted great interest and optimism around the mid-1990s. Ahead of the 15th licensing round, which covered the area, a big commitment was made, both nationally and in the oil companies, to long-term research on and technology development for deep water. The results of this work have already been implemented in projects with less demanding conditions, while other activities have continued even after disappointing exploration results on the Vøring Plateau. However, the discovery of Aasta Hansteen (Luva) was one outcome of this licensing round, and its development benefited greatly from the preceding technological advances.

Special safety challenges

Great attention is always paid in the project execution phase to topsides, which involve opportunities for HC leaks and many work operations. Compared with other NCS platforms, however, four areas in particular stood out as potentially safety-critical:

- the riser system

- the mooring system
- condensate storage
- the offshore loading system.

A riser system with SCRs has not been used before on the NCS or in other areas with a climate as tough as that on Aasta Hansteen. Platform motion and the interaction between platform, riser and seabed are critical for riser durability.

The deepwater mooring system and the use of polyester mooring lines contain new elements and are critical for the safety of the riser system.

Condensate storage is new for this type of platform and has increased its complexity.

Offshore loading has always been regarded as a weather-dependent and relatively risky operation. The Spar platform has a geostationary design, which means that tankers can lie in different positions in relation to it – depending on wind direction. Collisions between platform and tankers must be assessed specially.

The topsides are characterised by functionality and capacity, and their main layout does not differ significantly from that on a number of other Norwegian platforms. Equipment quantity, for example, is fairly similar to the Kristin facility. (However, Aasta Hansteen's total topsides weight is rather higher because of heavier steel structures.)

Topsides design is more similar to typical topsides on fixed platforms than on floaters, and does not differ with regard to area division.

4.2.5 Operator's safety analyses and assessments

In the PDO documentation, the operator notes that great emphasis had been placed in the project on a systematic approach to risk reduction in all activities. See Figure 4-13. The top priority was to develop an inherently safe concept, followed by work on risk reduction in accordance with the Alarp principle. A number of risk analyses were conducted with Hazid and qualitative as well as quantitative analyses.

Personnel risk was illustrated and quantified as calculated FAR values. The biggest contributions came from:

- process
- helicopter transport
- work-related accidents
- ship collisions.

The most important factors in relation to major accidents were:

- fires and explosions following ignition of HC leaks from the process plant
- helicopter transfer
- fatigue fractures in risers
- explosions in the condensate store.

The platform is divided into four main areas: process with flare boom, utilities, living quarters and hull.

An SSIV is fitted to the gas export riser at the subsea Plem to isolate the platform from the gas export pipeline. A similar system is not used against the production risers, which are much shorter and have smaller diameters.

Risers are always critical for a project which utilises a floating production unit, and their criticality rises with water depth.

Extensive model trials have been conducted to verify motion properties and safety in relation to wave slamming, green seas breaking over the Spar topsides and the clearance between waves and topsides.

Figure 4-13 presents an overview of the most important safety-related issues assessed by the operator in the early phase.

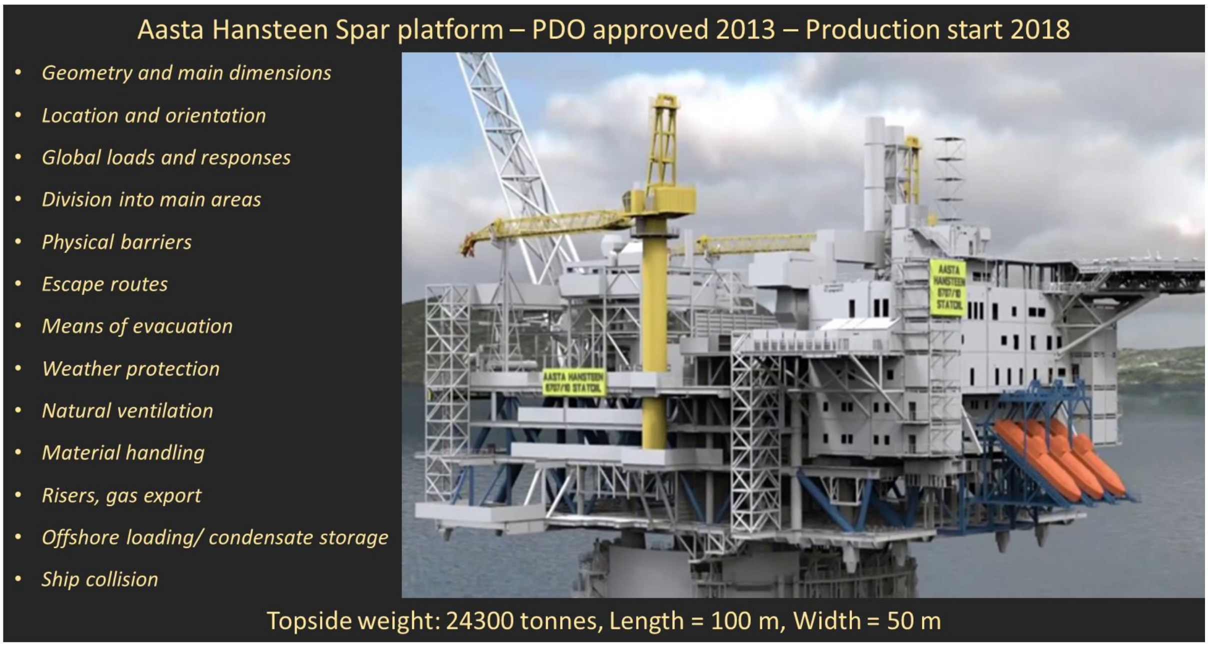


Figure 4-13. Safety-related issues assessed by the operator in the early phase. (Source: Acona)

4.2.6 Risk understanding and worker participation

The project devoted great attention from the start to critical elements of the concept:

- risers – materials and failure mechanisms
- mooring – materials and installation
- condensate storage – safety
- offshore loading – Goliat experience
- climate conditions – Multiconsult study
- weight control.

Equinor has several major projects under way in parallel at all times. Over the years, it has established a best practice on how to involve the safety service, unions and not least the operations team in the various project phases. This reduces the risk of later changes and contributes to production-friendly technical and operational solutions.

Risks were systematically identified as early as the feasibility studies and followed up systematically in all parts of the project in terms of establishing actions, implementing these and checking that they had the desired effect.

4.3 From DG2 to award of main contracts

4.3.1 PDO process

A substantial number of Spar platforms are operational today, primarily in deep water in the Gulf of Mexico. These have been delivered by Technip, which also holds certain patent rights related to the concept. This company was therefore an obvious candidate to deliver a Spar facility for Aasta Hansteen. At the same time, entering a Feed phase with only one supplier in a critical area presents a challenge for a partnership. An alternative "Spar" proposed by Aker was included as a competing solution, and Feed studies of the two concepts were conducted in parallel.

Feed studies were simultaneously carried out for the topsides, subsea production system, risers, flowlines and umbilicals. The extreme conditions on Aasta Hansteen (water depth, wind, currents, waves and low seabed temperatures) meant a number of elements in the development solution called for special attention – new technology. Examples include:

- Spar concept with condensate storage on the NCS

- mooring, including the use of polyester mooring lines
- SCRs, including solution for pull-in/hanging off
- system for well workovers.

Solutions were established by the Feed studies for both hull and topsides which provided the basis for realistic weight and cost estimates. Figure 4-14 presents developments in topsides weight from Feed to completion. Because experience indicates that some increase must be expected, a more conservative weight estimate was adopted at DG3. This was 22 593 tonnes, or 23 743 after risk adjustments. A final figure of 24 358 tonnes means the weight gain after DG3 was only 2.6 per cent. Increases for the hull were even smaller.

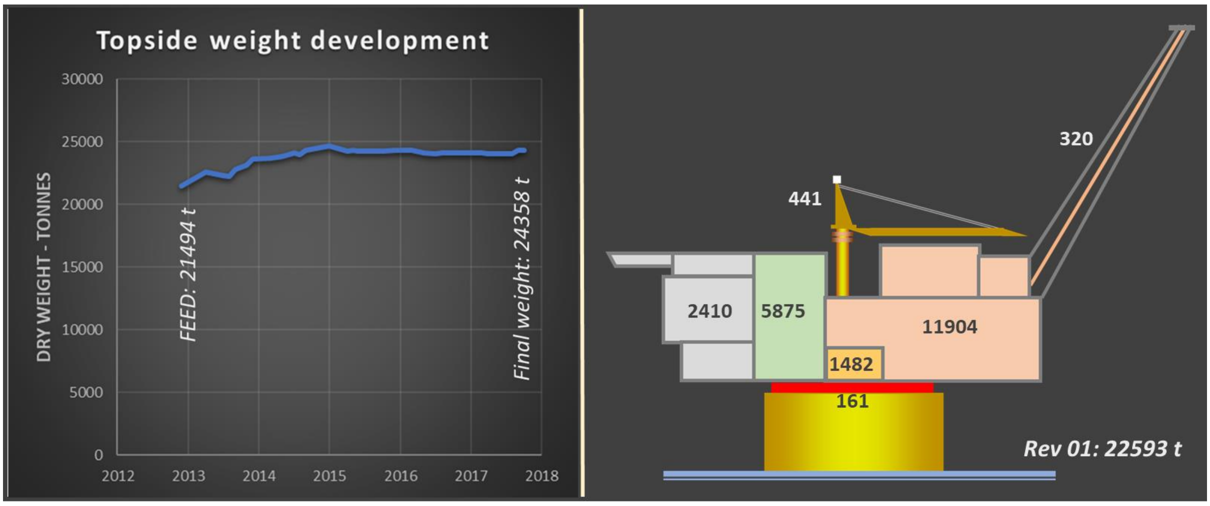


Figure 4-14. Topsides weight development and overview. (Source: Acona)

Topsides dry weight provides the basis for cost calculations and is an important figure for weight reporting and control. Normal practice is to divide it between equipment weights, bulk weights per discipline and construction steel. Weight composition varies from platform to platform, but a marked deviation from the average should be investigated in more detail.

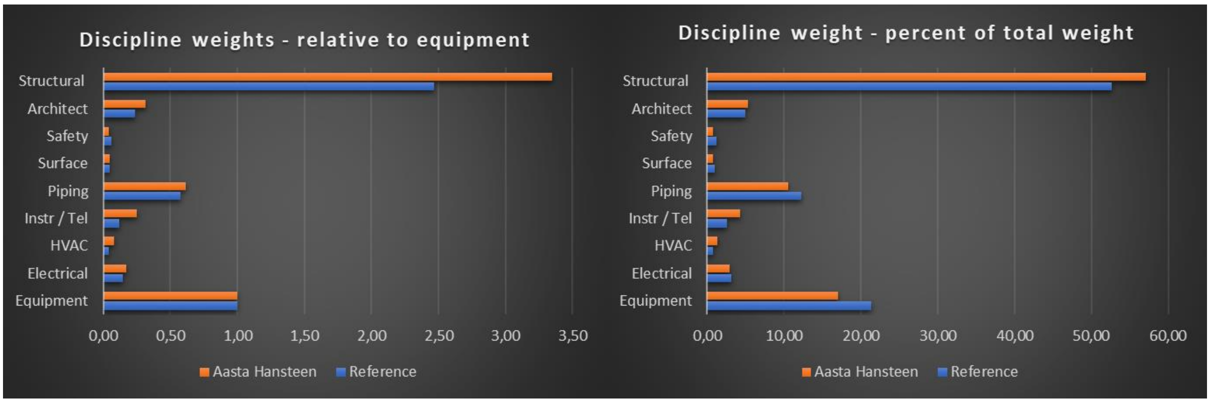


Figure 4-15. Analysis of discipline weights. (Source: Acona)

Figure 4-15a presents discipline weights in relation to equipment weights. Weights for Aasta Hansteen's topsides are compared with average values for 16 different platforms (references). Figure 4-15b presents discipline weights as a percentage of total dry weight for Aasta Hansteen and the reference projects.

The figure shows that Aasta Hansteen's weights deviate little from the average for the reference projects, except for the fact that the share of construction steel is high.

After DG2, a systematic investigation was conducted to improve and simplify the process plant. This led to some measures, but no major changes.

However, it became clear that the decision to incorporate condensate storage in the hull had bigger consequences than expected. HC inside the hull's main structure, combined with the need for safe access by lifts and stairs very much increased complexity. In addition, a more complicated and active ballast system was needed to be able to control the platform's draught when the condensate store was filled to different levels.

4.3.2 The government's assessments and conditions – Proposition 97 (2012-13) to the Storting

Main conclusion: the MPE approves the PDO of Aasta Hansteen field in accordance with the plans submitted by the operator and the comments presented in this Proposition.

In connection with their consideration of the PDO, the PSA and the NPD had the following comments:

> The PSA has certain comments which are specified in the Proposition text, but sees no need to set special conditions and recommends that the plans be approved. The ASD has no additional observations.
>
> Various development solutions for Aasta Hansteen have been assessed by the licensees in an early phase. The main alternative to today's development solutions were various subsea development variants with landing to Nordland, other fields in the Norwegian Sea or directly to Nyhamna. The chosen solution came across as advantageous, based on higher present value, less need to mature technology and increased opportunities for resource utilisation in Aasta Hansteen and the surrounding area. On that basis, the NPD has no objections to the operator's choice of concept. Nor has the NPD had objections to the choice of the Spar concept at the expense of alternatives, particularly FPSOs and a semi-sub/TLP.
>
> The NPD notes that the licensees have implemented extensive technology qualification up to the submission of the PDO. Although the technology qualification has been implemented, the NPD would observe that the development solutions involve a number of elements which are new and untested for the operator and/or the NCS. The project therefore contains elements of risk which call for very good project and contract management by the operator. The NPD also wants to call attention to the fact that the development will take place in a period when a very high level of activity prevails in the petroleum sector, which could pose challenges in relation to the availability of materials and costs. The NPD notes that new information from suppliers on delivery times has resulted in a postponement of the expected start to production from the fourth quarter of 2016 to the third quarter of 2017.
>
> Calculations of power from shore by the operator show high supplementary costs, and the NPD therefore supports the operator's assessment that Aasta Hansteen be developed with gas turbines. The NPD notes the gas turbine for export compression has heat recovery (for the process and the living quarters), and can thereby achieve a higher level of efficiency. The NPD had no comments on the impact assessment.
>
> The NPD takes the view that the operator, with the present development plans, makes good provision for new and existing discoveries in the area, both within and beyond the Aasta Hansteen licence.

4.3.3 Contract strategies. Prequalification, tender documents and format

Technip was commissioned in July 2012 to design, procure and deliver the Spar platform hull ready for mating with the platform topsides in Norway. The supplier was also to design and prepare specifications for SCRs and for a complete mooring system.

As hull supplier, Technip had to establish cooperation with a yard. Virtually all earlier Spar platforms have been built at a Finnish yard which has specialised in such structures over more than 20 years. Because this yard was fully engaged on another project, Technip now decided to enter into a collaboration with HHI, which in turn contracted with Kværner for mating and completion of hull and topsides at Stord.

The fact that the topsides contract was also awarded to HHI with CB&I responsible for engineering was an unrelated matter.

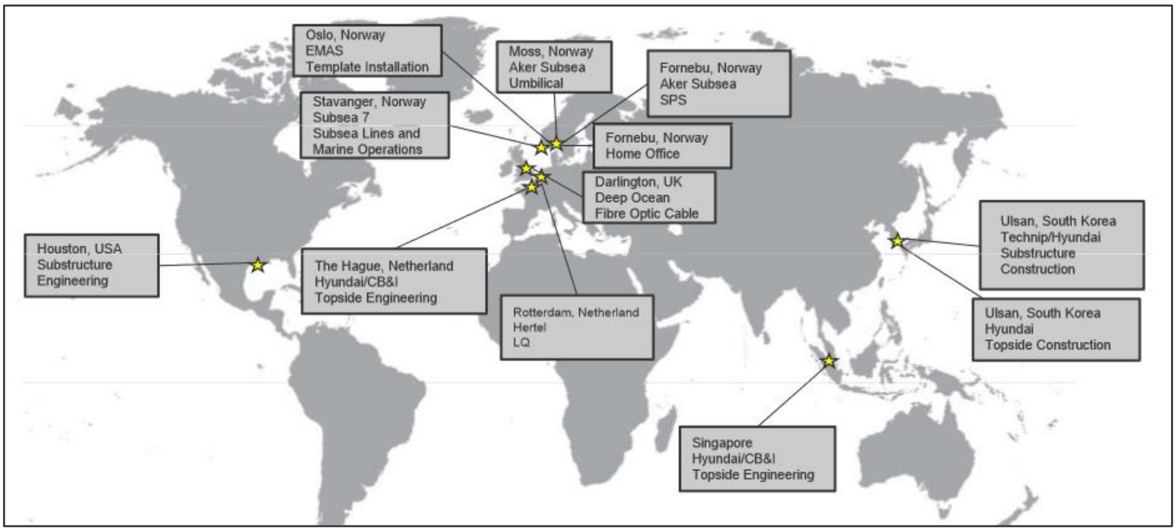


Figure 4-16. Placing of the most important contracts. (Source: Equinor)

4.4 From DG3 until the platform arrived in Norway

4.4.1 Construction phase at HHI

The level of activity at contract award was very high, and Aasta Hansteen ended up in reality in a priority queue. This meant the work began late and it became clear at an early stage that the plan for completion had to be revised.

While HHI actually had 23 000 people at work, the optimal planned manning should not have exceeded 13 000 to achieve acceptable productivity. Poor productivity reflected far too many workers without supervision and relatively expensive contract labour. When the project finally received priority, it made rapid progress. Deficiencies in the Feed work also contributed to engineering for the platform falling behind, making it necessary to increase/intensify follow-up in the execution phase.

Equinor was a partner in the Goliat project, which had entered into a similar contract with HHI three years earlier. It thereby had opportunities to draw on its experience concerning the level of activity/quality/expertise/management and so forth. Equinor succeeded in getting the necessary corrective measures implemented so that the negative consequences were reduced to a substantial delay, but with only a small cost increase. The quality of the work at the yard also seems to have been significantly higher than on Goliat.

The complexity of building the hull was underestimated. Generally speaking, a structure with a circular cross-section is less construction-friendly than a rectangular one, and building the cylindrical section while in a horizontal position made it particularly difficult. Constructing the hull therefore became crucial for completion of the project.

Although earlier Spar platforms had lacked storage, this was regarded as a manageable extension of the concept. However, it became clear at an early stage that the decision to incorporate condensate storage in the hull had bigger consequences than expected. HC inside the hull's main structure, combined with the need for safe access with lifts and stairs, increased complexity a great deal. In addition, a more complicated and active ballast system was needed to be able to control the platform's draught when the condensate store was filled to different levels.

The Spar hull was on the critical path in terms of time. The project was not given priority initially by HHI and thereby became considerably delayed. In addition, the complexity/scope of work increased, so that the construction period lengthened from 13 to 35 months. Work on the Spar structure was underestimated and rose from 2.5 million hours to 10 million.

Bringing the facility on stream was delayed at an early stage by 12 months, to the third quarter of 2018. Total time taken from DG3 to DG4 was ultimately 71 months, far longer than with comparable projects. The Spar structure with storage ended up costing roughly NOK 6.5 billion, well over the PDO estimate.

Challenges in the construction phase are identified in the annual MPE reporting:

> 2015: An increase of about NOK 650 million in the investment estimate since the PDO has been reported for the Aasta Hansteen project. The rise from the same reporting last year is NOK 560 million. This increase reflects an extended construction period in South Korea. After reporting cost changes for the project in June 2015, the operator has informed the ministry of further delays to building the platform. This means that coming on stream could be postponed until 2018. Work is under way to establish the financial consequences of this. The ministry will revert with updates on the project in the Proposition on a new balancing of the budget for 2015.

4.4.2 Platform EPC contractor's ability to accept turnkey responsibility

Management and execution of the project at HHI appear to have got off on the wrong foot for both platform hull and topsides, with delays to engineering and thereby postponements to procurement and construction. HHI had no experience with this type of complicated contract with turnkey responsibility and lacked sufficient qualified personnel at the start.

HHI failed to meet the contract's requirements for management/follow-up of subcontractors, progress reporting, costs/change orders, updated plans or quantification of the risk picture with measures.

Equinor was hands-on with engineering, procurement and planning from the start, not least with engineering contractor CB&I, so that it was the operator's team in reality which took on HHI's EPC responsibility. Equinor undertook the detailed follow-up checking of weight developments and the quality of work done. HHI lacked expertise with engineering and procurement follow-up.

HHI is first and foremost a fabrication yard. Time spent on construction ended up at about 10 million hours, both on the Spar hull and on the topsides.

4.4.3 HSE at the construction site

Statoil (now Equinor) was and is a partner in Goliat. It therefore had access to experience transfer from Eni, which had initiated construction of the platform for that field at the same yard three years earlier. Aasta Hansteen was taken on by HHI at about the time when the yard's HSE accounting began to show that its risk management was unable to halt a growing negative trend. As described in the chapter on Goliat, 2014 was the most challenging year for HHI in terms of HSE. Statoil has explained in interviews that it was conscious of this position and therefore concentrated attention on HSE in meetings with HHI at all levels of the organisation. The operator also familiarised itself with HHI's organisation of the work and use of subcontractors. It considered that the most effective approach to improving the HSE statistics would be for the subcontractors to become more directly involved with and rewarded for positive results in this area. Statoil succeeded in achieving that through negotiations with HHI's project management.

Statoil has explained that the safety challenges which had to be tackled in connection with construction of the Spar platform were much greater than had been envisaged in advance. The dimensions and configuration of the platform were the reason why materials management, for example, and logistics during construction became particularly challenging. As soon as the challenges faced were identified, however, attention was focused on safety during the conduct of work operations.

Despite the strong attention paid to HSE and Statoil's active involvement at HHI's construction sites, the project experienced an incident which could have been fatal with a marginal change in the course of events. In the spring of 2016, a steel plate dropped to an unsecured area and hit a person present there. The latter suffered a leg injury and required an operation.

The Aasta Hansteen hull and topsides were delivered separately from South Korea and assembled at Kværner Stord. That job began in late 2017, more than two years behind the original schedule. After a few months at Stord, the platform was towed to the Norwegian Sea field and installed there. No significant HSE nonconformities or injuries were reported while the platform was in western Norway.

4.4.4 Completion at the construction site – readying for offshore completion

The extended construction time at the yard and Equinor's detailed follow-up meant that both projects (Spar hull and topsides) had a high level of completion to acceptable quality before transport to Norway.

Experience indicates that completion of simple platforms offshore should take six months in all, while the project used eight. This could reflect the project's complexity/new solution.

4.5 Subsea installations, drilling and well operations

4.5.1 Project review for subsea installations

Aasta Hansteen lies in 1 250-1 300 metres of water, rather deeper than Ormen Lange but nevertheless at a moderate depth compared with the really deepwater areas in the Gulf of Mexico, west Africa and Brazil. The technology for operating in these regions has been qualified and developed over many years in a way which optimises safe and efficient operations. Deepwater technology is international in its character – the same standards, operational methods and equipment are used worldwide.

The special design challenges with Aasta Hansteen have been:

- reserves spread over several small structures –linking these efficiently
- steel risers – estimating commercial life in the given natural conditions
- a harsh environment – including well workover system for sub-zero conditions

Water depths on the field rule out trawling, which has simplified field layout compared with other subsea developments on the NCS.

Project execution of the SPS

Aker Solutions was awarded the engineering, procurement and assembly contract for the subsea facilities on Aasta Hansteen. This assignment covered eight wells in four four-slot seabed templates with associated control equipment and spare parts.

Two technical qualification programmes were initiated for the subsea systems:

- well workover system
- seven-inch downhole safety valve.

Both programmes were launched early and conducted in accordance with Equinor's standards and guidelines. Equipment from Aker Solutions was delivered and installed to the agreed schedule and on budget.

Equinor involved north Norwegian industry to a great extent for deliveries to the project where relevant, with positive outcomes and good feedback from the players.

Project execution for flowlines, umbilicals, risers and marine operations

Subsea 7 was chosen as the supplier of flowlines, umbilicals, risers and marine operations. This work was done in a satisfactory manner in line with plans and with a 15 per cent cost reduction from DG3 to DG4.

The HSE results were also very good:

- no serious incidents
- one injured finger
- no quality incidents.

The four SCRs on Aasta Hansteen, three for production from the templates and one for gas export, were tied back to a floater. This is new technology for the NCS. Equinor has been researching and testing this type of solution for many years, but Aasta Hansteen represents its first adoption. The project implemented the solution in an outstanding manner and came up with risk-reducing measures to compensate for the uncertainty in the calculation models for fatigue. One of the four risers is instrumented to register motion loads in order to be able to calibrate uncertainty in the models.

4.5.2 Drilling and well

Reservoirs making up the Aasta Hansteen field lie 3 000 metres beneath sea level and have relatively low temperatures, from 60-80°C. Pressure in the reservoirs varies between 284 and 338 bar – virtually hydrostatic. This is a gas/condensate field, with pressure depletion as the drainage strategy. Possible sand production is controlled/halted with the aid of sand filters and gravel packing. Since pressure in the reservoirs is hydrostatic and the wells penetrate them at an angle of about 45 degrees, completions are relatively simple and short.

The wells have been drilled and completed by *Transocean Spitsbergen*, a sixth-generation semi-submersible rig with twin derricks which is built to cope with the hardest climate.

Equinor planned drilling and completion on the basis of the rig's capabilities and made full use of the opportunity to drill two wells simultaneously in the same template. This cut the drilling schedule by 75 days, corresponding to a cost saving of NOK 580 million.

HSE results were also very good.

4.6 Offshore hook-up and completion

4.6.1 Marine operations

The *Dockwise Vanguard* heavy-lift vessel arrived at Høylandsbygd in Kvinnherad on 18 June 2017 with the hull for the Aasta Hansteen platform. This structure was raised from horizontal to vertical position – an operation taking about 10 days – before being towed to Digernessundet outside Stord.

On 30 November 2017, the *Dockwise White Merlin* heavy lift ship arrived at Westcon Yards in Ølensvåg with the Aasta Hansteen topsides. The voyage took about two months.

The topsides was transferred to two barges at Ølensvåg before being transported on to Digernessundet, where they were mated with and hooked up to the hull by Kværner/Technip before transport to the field. The Aasta Hansteen platform tow-out was the largest on the NCS since Troll A in 1995. It weighs 70 000 tonnes and stands 339 metres high.

With an average speed of two knots, the 500-nautical-mile tow from Digernessundet to Aasta Hansteen took 11 days. Five tugs from three companies, with a combined 150 000hp, performed this operation.

The platform arrived on 23 April 2018. A week later, it was secured with 17 anchors and more than 40 000 metres of mooring rope in 1 300 metres of water.

4.6.2 Flare system

Bottleneck studies identified possible problems related to acoustic induced vibrations (AIV) in the flare system. Special transitions were utilised to ensure sufficient strength in piping branch connections. Weldolets rather than sweepolets were used on Aasta Hansteen because they represent a cheaper/simpler solution.

The PSA was briefed in January 2018 about possible solutions, including reinforcement of weldolets.

No information has emerged during this study which suggests the problem has not been overcome. This experience has been transferred to other projects.

4.6.3 Start-up decision

The PSA's consent to take the platform into use was given on 8 March 2018. On 31 August 2018, the NPD could announce that Equinor had received consent to bring the Aasta Hansteen platform on stream. That occurred on 16 December 2018.

Experience indicates that completion of topsides of this size offshore should take six months in all, while the project used eight. That reflected faults/technical problems with certain equipment components, which had to be replaced. Although the project faced some challenges which caused a little delay in the completion phase, it was never relevant to come on stream until the facility had been completed in accordance with the prevailing safety requirements.

4.7 Production phase from start-up to the spring of 2019

4.7.1 Production preparations and readying for start-up

The most serious of the incidents notified to the PSA since the platform arrived on the field (but before the process facilities were taken into use in December 2018) is a personal injury which occurred in connection with material handling. While opening a wooden case with the aid of sledgehammer, one person was seriously injured when a hammer blow missed. The hammer glanced towards the assistant on the job, who was struck on the body and head. Equinor has conducted an internal investigation of the incident, primarily with the aim of learning lessons and in order to identify measures which will help to reduce risk in connection with this type of work operation.

In other words, the Aasta Hansteen development completed the fabrication and completion phases without loss of life and with only two known incidents involving serious personal injury.

4.7.2 On stream – regularity, HSE and safe platform operation

Aasta Hansteen came on stream on 16 December 2018, and gas was exported to the Polarled pipeline for the first time on the following day. Since the start-up, no incidents with consequences for HSE have been reported or notified. Nor has the PSA conducted any audits so far during the Aasta Hansteen production phase.

Production began from Aasta Hansteen after a 15-month delay in relation to the PDO's assumptions. Following some running-in problems which can primarily be related to cleaning wells and bringing them on stream, the field is now producing at full capacity. Average daily gas exports in March 2019 were 22.6 million scm. This means that Aasta Hansteen had reached full capacity just 2.5 months after coming on stream. See Figure 4-17. The accumulated volume of gas exported during the first 3.5 months was 1 234 million scm. Condensate production during the same period came to 21 520 scm.

If production capacity is defined as the highest monthly average attained, capacity utilisation over the first 3.5 months can be said to have been 51 per cent.

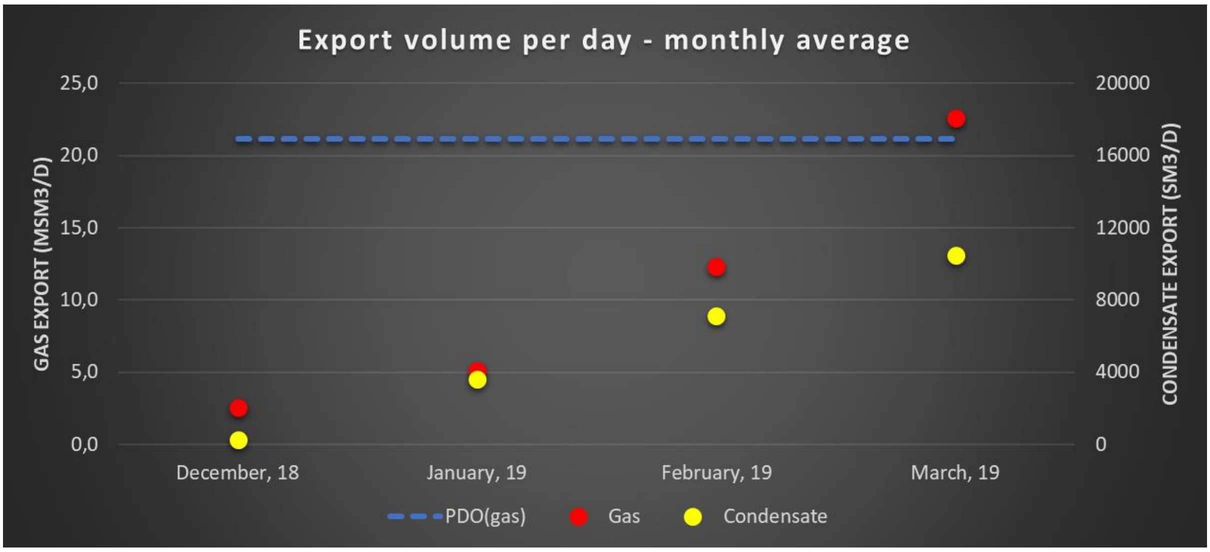


Figure 4-17. Production in the start-up phase – gas and condensate. (Source: Acona)

No serious incidents with consequences for HSE were reported or notified after start-up until a gas leak on 8 April 2019. This incident was still being investigated when this study was finalised. However, the absence of personal injuries or production disruptions in an incident is not synonymous with no HSE gain being obtained from correcting its causes.

To demonstrate this, mention can be made of incidents related to the following.

- Spill of produced water from overfilling the slop tank. Exposure over time to compounds in this water represents a health risk. The HSE incident log refers to several occurrences of this incident.
- Instability and operational failure with images projected onto the big screen in the control room. Part of the information on the screen disappears or blinks, so that the operators must rely on their own work stations alone to get an overview. Manning in today's control rooms is based on all information systems functioning optimally for handling the defined work operations. A change in information provision could affect operator response time and, in the worst case, the time taken to implement measures should a serious incident occur.

The platform has also experienced a number of minor gas leaks. Most of these have been picked up by field operators on inspection rounds or in other ongoing work and fall into the category of diffuse leaks. The scope of these leaks has been so small that the gas detection system will not normally pick them up. A general reason for this category of incident can be said to be a lack of quality control during project execution, but identifying all such faults before coming on stream would call for an almost unrealistic level of detail in the quality assurance system. It is therefore important to pay attention to correct execution at all levels, in the design processes, in preparing package specifications during procurement and follow-up of suppliers and subsuppliers, and in fabrication/installation.

Those few cases where incipient fires or escapes of rather larger gas quantities have occurred were quickly identified by the automatic detection system. Automatic and operational actions (emergency responses) were quickly initiated and were relevant to the condition which had arisen.

A total of 316 helicopter flights were made to Aasta Hansteen between 2 April 2018 and 4 April 2019, and 41 planned flights cancelled. These cancellations were largely prompted by weather conditions at Brønnøysund or along the flight path, the availability of SAR, or landing conditions on Aasta Hansteen.

In certain wind conditions, the design of an exhaust stack may cause turbulence in excess of the acceptance criteria for helicopter landing (red deck). According to statistics used in the design process, these conditions will occur at an acceptable frequency in relation to the criteria for an operational helideck. A somewhat higher frequency was experienced during the first half-year, and the decision has therefore been taken to raise the height of the stack during the turnaround in September. This condition does not arise during production shutdowns, and the platform management can, if required, decide to cease production to safeguard landing conditions. The Halten-Nordland area emergency response organisation has a SAR helicopter based on Heidrun. Should weather conditions there require that the SAR machine returns to land, flights to Aasta Hansteen would be restricted.

As with other floaters, motion caused by waves, currents and wind could cause crane movements which prevent loading/unloading operations with supply ships. The company has no statistics about when cranes have been inoperable because of weather conditions.

Emergency preparedness must be maintained at all times on Equinor's installations. In the event of an incident, helicopters will be the primary means of evacuation. Should the helideck be out of operation, lifeboats (secondary means of evacuation) can be used. Personnel have experienced having to postpone departure to/from Aasta Hansteen because of delays to helicopter flights, but manning on board is always sufficient to populate the emergency response organisation. Safe operation/production on Aasta Hansteen has not been affected by logistical challenges.

4.7.3 Regularity, HSE and safe operation – wells and subsea installations

The seven subsea wells are all on stream and producing 1.4 to six million cubic metres of gas per day. D3, the well with the lowest output, has reduced capacity which is suspected to reflect damaged gravel packing against the reservoir. The wells are functioning as expected, apart from during well cleaning to the platform when particles, bits of aluminium, cement, sand and so forth were produced. That caused a bigger pressure drop than expected in the choke valves on the wells. The cause is assumed to be particles blocking the valve opening. Investigations have been initiated, and replacing the choke valves could be relevant. Furthermore, Equinor has analysed the relationship between flow speeds and particle lift in the risers in order to ensure that the particles are lifted out. Cleaning of subsea wells has previously been done by mobile rigs with associated flaring of oil and gas. Primarily for environmental reasons, it has become practice on the NCS to clean to the production platform. The Aasta Hansteen example shows that this is a demanding and complex operation which calls for good and careful planning.

4.7.4 Project status at the second quarter of 2019

Aasta Hansteen came on stream on 16 December 2018 and gas was exported to Polarled from the following day. No serious incidents with consequences for HSE have been reported or notified since start-up. The PSA has only conducted one safety audit since start-up, in January 2019. After two months with some start-up problems, the platform is now in a stable production phase.

4.8 Operator's organisation, partner follow-up and government

4.8.1 Project organisation

Statoil (now Equinor) has developed a standard organisational model for its projects over a long period. See Figure 4-18. This was also used for the Aasta Hansteen project.

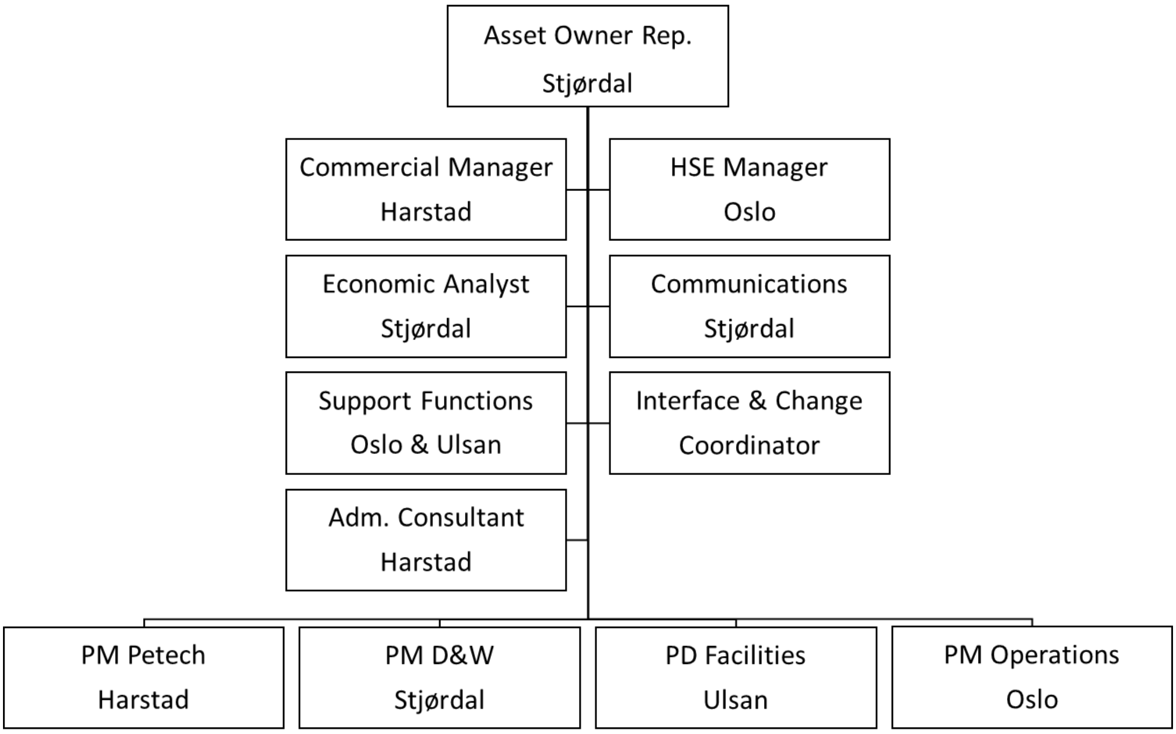


Figure 4-18. Aasta Hansteen organisation 2015. (Source: Equinor)

From arrival in Norway until start-up, the project was organised as shown in Figure 4-19.

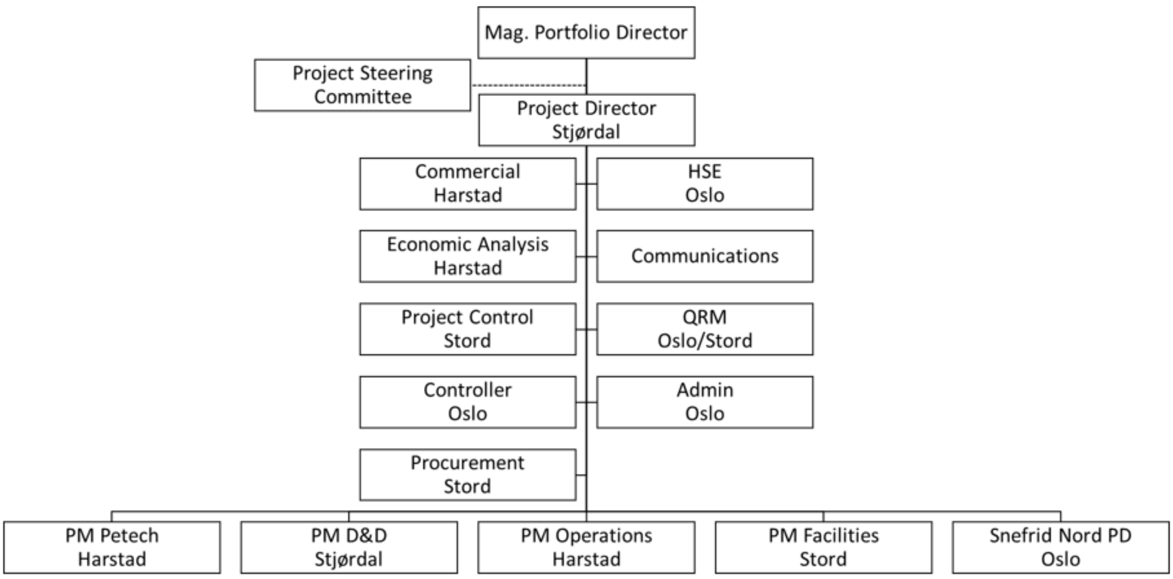


Figure 4-19. Aasta Hansteen organisation 2018. (Source: Equinor)

4.8.2 Partner role and involvement

Companies such as Esso and ConocoPhillips were partners in the early phase and played an active part in the process up to choice of concept and PDO submission. The present partners, with ConocoPhillips in the lead, have been hands-on with the project throughout the execution phase. The study team's assessment is that this partnership has met the requirements imposed on it by agreements and regulations.

4.8.3 Government's role

The overall project risk assessment for Aasta Hansteen emphasises that the development's many new technological solutions, including the floater concept, tough weather and environmental conditions, size and financial robustness, as well as the choice of contract strategy in an overheated market, posed a substantial risk for project execution.

This is also reflected in the subjects covered by the PSA's audits of the Aasta Hansteen development. That is to say, several of them were directed at Statoil's project management of the contracts for new technology. They also covered subjects related to the PSA's general priority areas – in other words, major accident risk and barrier management as well as the working environment and materials management. Each audit was directed at new subjects – none were follow-ups. This means the PSA has regarded Equinor's response to nonconformities and improvement points identified in an audit as satisfactory.

The PSA has so far carried out 13 audits of Aasta Hansteen. Since Gassco is the operator for Polarled, audits of the pipeline from the field to Nyhamna are not considered to be directed at the Aasta Hansteen development. Because Aasta Hansteen came on stream in December 2018, no audits had been staged in the production phase by March 2019. The audits break down roughly 50-50 between the engineering and fabrication/completion phases.

Since the Aasta Hansteen development contains so many and such large elements of new technology, the operator's management of technology qualification will be significant for the project's overall quality and progress. However, its technology qualification programme, procedures and plans have not been addressed in a dedicated audit.

Reporting to the government has been good and veracious, which is reflected in the comments in government Finance Bills along the way. See appendix B.

4.9 Overall assessments

4.9.1 The project's preconditions and parameters

The starting point for the Aasta Hansteen project was:

- limited reservoir complexity and uncertainty
- medium-sized in terms of capacity and platform facilities
- uncomplicated production facilities
- basically marginal commerciality
- opportunities for increased activity through further exploration in the area
- limited attention from stakeholders
- long way from infrastructure
- new platform solution (Spar with storage)
- substantial degree of technology qualification
- experienced NCS operator
- EPC with execution in Korea
- realistic overall plan and budget in the PDO.

4.9.2 Platform's concept maturation and execution

The following assessments have been made from a technical perspective. Only limited account has been taken of commercial and contractual conditions.

Location and new technology

Aasta Hansteen lies in the northern Norwegian Sea, 140 kilometres north of Norne and 300 west of Bodø, and is thereby relatively far from land and existing infrastructure. The water depth in the area is about 1 300 metres, and the combination of wind, waves and currents is worse than in most parts of the NCS. This makes developing Aasta Hansteen technologically demanding and not a standardised/routine assignment.

In addition to satisfying field-specific demands, the project was expected to make provision for developing other discoveries in the area.

Choice of concept

Systematic work on field development studies began in 2009. Until late 2011 (in other words, during 2009-11), systematic studies were conducted on relevant concepts. The assessments made and conclusions drawn appear to accord with good practice, and choice of concept was made in late 2011.

After various solutions based on subsea wells alone were rejected, the most appropriate platform solution had to be found. The assumption that the facility would have integrated condensate storage and SCRs meant the only qualified option was a Spar type. See below.

Condensate storage

Aasta Hansteen produces a small amount of condensate, and finding an acceptable solution for this was important. The preferred solution was a small condensate store integrated in the platform hull. Solutions requiring a separate storage ship or based on condensate injection either below ground or into the gas pipeline were rejected.

Although earlier Spar platforms had lacked storage, this was regarded as a manageable extension of the concept. However, it became clear at an early stage that the decision to incorporate condensate storage in the hull had bigger consequences than expected. HC inside the hull's main structure, combined with the need for safe access with lifts and stairs, greatly increased complexity. Relatively stringent Norwegian regulations may have contributed to the cost increase here. A more complicated and active ballast system was also needed to be able to control the platform's draught when the condensate storage was filled to different levels.

Risers

The risers are always critical in projects which utilise floating production units, and their criticality increases with water depth. Flexible risers are used to a great extent on the NCS. These are subject to wear and persistent dynamic loads, and have a limited working life. That therefore calls for monitoring, inspection and replacement. In water depths as great as on Aasta Hansteen, external pressure becomes a further factor which must be included in the dimensioning. That may limit riser diameter and make it smaller than the flowlines.

SCRs were developed and adopted as export risers for deepwater TLPs in the Gulf of Mexico. They were later also adopted as production risers on Spar units and other deep-draught platforms. But they have never previously been used on the NCS or in other areas with similar weather conditions. Aasta Hansteen was a project which could benefit greatly by opting for SCRs. The precondition for selecting them was a platform with very good motion properties. A Spar solution was considered to possess these. At the time when the choice of concept was made, no qualified alternative to this design was available with opportunities for condensate storage.

Competing Spar platforms

A substantial number of Spar platforms are operational today, primarily in deep water in the Gulf of Mexico. These have been delivered by Technip, which also holds certain patent rights related to the concept. This company was therefore an obvious candidate to deliver a Spar facility for Aasta Hansteen. At the same time, entering a Feed phase with only one supplier in a critical area presents a challenge for a partnership. An alternative "Spar" proposed by Aker was therefore included as a competing solution, and Feed studies of the two concepts were conducted in parallel.

Platform construction

The level of activity at contract award was very high, and Aasta Hansteen ended up in reality in a priority queue. This meant the work began late and it became clear at an early stage that the plan for completion had to be revised.

Deficiencies in the Feed work also contributed to engineering for the platform falling behind, making it necessary to increase/intensify follow-up in the execution phase.

Equinor succeeded in getting the necessary corrective measures implemented so that the negative consequences were reduced to a substantial delay, but with only a small cost increase.

The complexity of building the hull was underestimated. Generally speaking, a structure with a circular cross-section is less construction-friendly than a rectangular one, and building the cylindrical section while in a horizontal position made it particularly difficult. Constructing the hull therefore became crucial for completion of the project.

Fabricating the topsides for Aasta Hansteen was also a large and demanding project, but nothing extraordinary by NCS standards. Equipment quantity, for example, is fairly similar to the Kristin facility. (However, Aasta Hansteen's total topsides weight is rather higher because of heavier steel structures.)

4.10 Learning points

General. Aasta Hansteen lies in the northern Norwegian Sea, far from land and existing infrastructure. The water depth in the area is about 1 300 metres, and the combination of wind, waves and currents ranks among the worst on the NCS. This basically meant that its development was unusually demanding.

Technology qualification and choice of concept. The Aasta Hansteen project was dependent on technology qualification, and benefited greatly from the long-term deepwater research which had been initiated even before the 15th licensing round.

A topsides with intake, process and export systems always poses a risk of HC leaks and work accidents. Compared with other platforms on the NCS, however, four areas in particular stand out as potentially safety-critical:

- the riser system
- the mooring system
- condensate storage/handling
- the system for offshore loading.

These areas received great attention in the project, and technology qualification was implemented as planned. Nevertheless, some areas will require attention in the production phase, with the soundness of the development concept assessed on the basis of the experience obtained.

Effect of the layout on costs and execution. Costs for the Spar platform turned out to be high, and the construction period was long. An alternative to a Spar would have been a shallow-draught design like the Goliat floater. But such a platform would probably have required flexible risers. Without extensive analyses, it is impossible to say anything certain about the cost differential.

The Aasta Hansteen and Goliat topsides are presented in Figure 4-20. Since Aasta Hansteen is a gas field and Goliat primarily produces oil, their platforms have big differences in equipment and systems. However, the total dry weights are not that different.

Figure 4-20. Comparison of Goliat and Aasta Hansteen topsides. (Source: Acona)

The Aasta Hansteen topsides are configured in the same way as a conventional structure on a fixed platform, while those on Goliat are very special because of its circular shape. As the assessment of Goliat indicates, most of the problems were related to the topsides. The Aasta Hansteen project avoided these difficulties, so the solution for that field must be considered more successful.

Differences in choice of topsides solution related to hull diameter. This is 50 metres for Aasta Hansteen, while its topsides are 100 metres long. That made it possible to position the topsides over the hull with a barge at each end. The diameter of Goliat’s process-deck level is 107 metres. It was thereby impossible to build and install the topsides as a single unit. The chosen method with many small sections proved unfavourable.

The Aasta Hansteen topsides has a fairly large overhang. See Figure 4-20. Although this represents a construction challenge to some extent, it has already been solved satisfactorily on a number of other platforms. It is conceivable (although unlikely) that a large vessel off course could collide with the living quarters.

When a Spar was chosen as the platform concept, the complexity introduced by including several new functions in the hull was underestimated. The construction methodology and associated requirements for safety – and thereby also time – had not been thought through well enough in the early phases. That led to an unrealistic plan and thereby delays to the overall project. The lesson is that a greater commitment should be made in the early phase when introducing major changes to something built before, and a more detailed approach taken than with more conventional solutions.

Project plan. The operator underestimated the complexity of the platform concept and had not done the work needed in the early phase to establish a realistic and viable plan.

A positive lesson is that a proper risk review and impact assessments must be conducted for the overall project when it has become clear that the plan for part of it is unviable and, on that basis, the most value-creating alternative selected. In this case, the option chosen was a 12-month delay in coming on stream.

Organisation and execution model. The effect of having an operator with a large, experienced and well-run project organisation can clearly be seen. This ensures good understanding of good risk management, professional self-regulation and quality assurance as well as effective project follow-up, interface control and change control. The same can be said of a well-established relationship and division of responsibility between the operations and project organisations.

5 Ivar Aasen

5.1 Overall project description

5.1.1 Location, licensees and reservoir description

Ivar Aasen lies in the northern North Sea, 30 kilometres south of Grane and Balder. The water depth is 110 metres. Discovered in 2008, the field's PDO was approved in 2013.

The Ivar Aasen project covered the development of three discoveries: Ivar Aasen, Hanz and West Cable, and is used a collective term for the development. Ivar Aasen and Hanz contain oil and gas, while West Cable is thought to contain only oil. The Ivar Aasen deposit was confirmed by well 16/1-9 in the spring of 2008. An important appraisal well, 16/-11, was drilled in the spring of 2010.

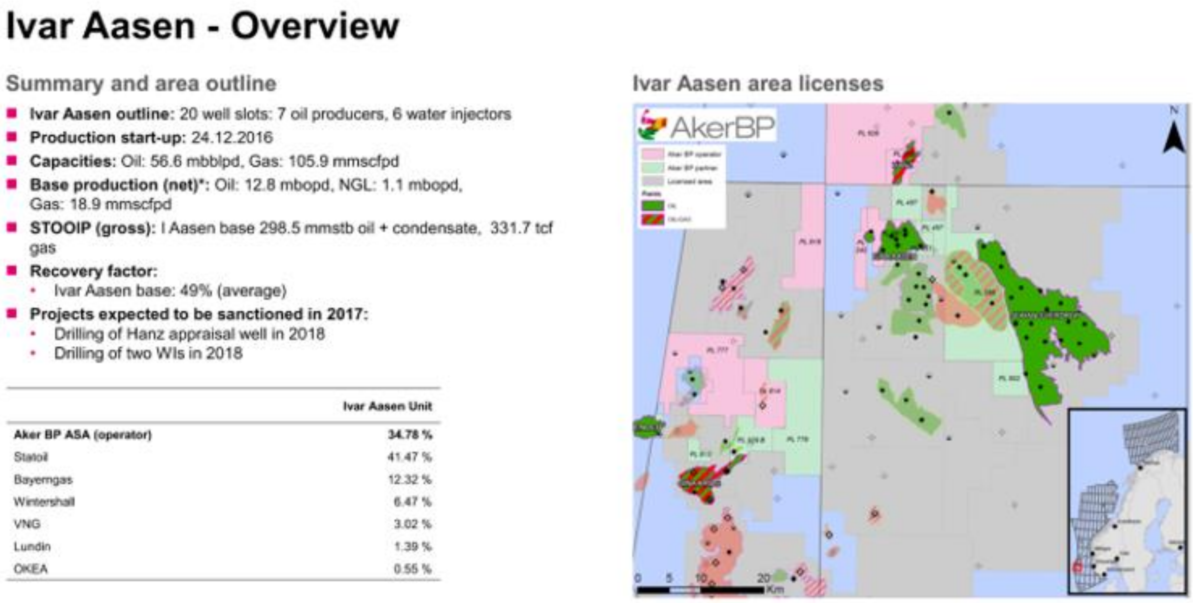


Figure 5-1. Location. (Source: Aker BP)

Figure 5-2. Overview of Ivar Aasen reservoirs. (Source: Aker BP)

5.1.2 *Licence history and project overview*

Figure 5-3 presents an overview of the most important issues in each project phase.

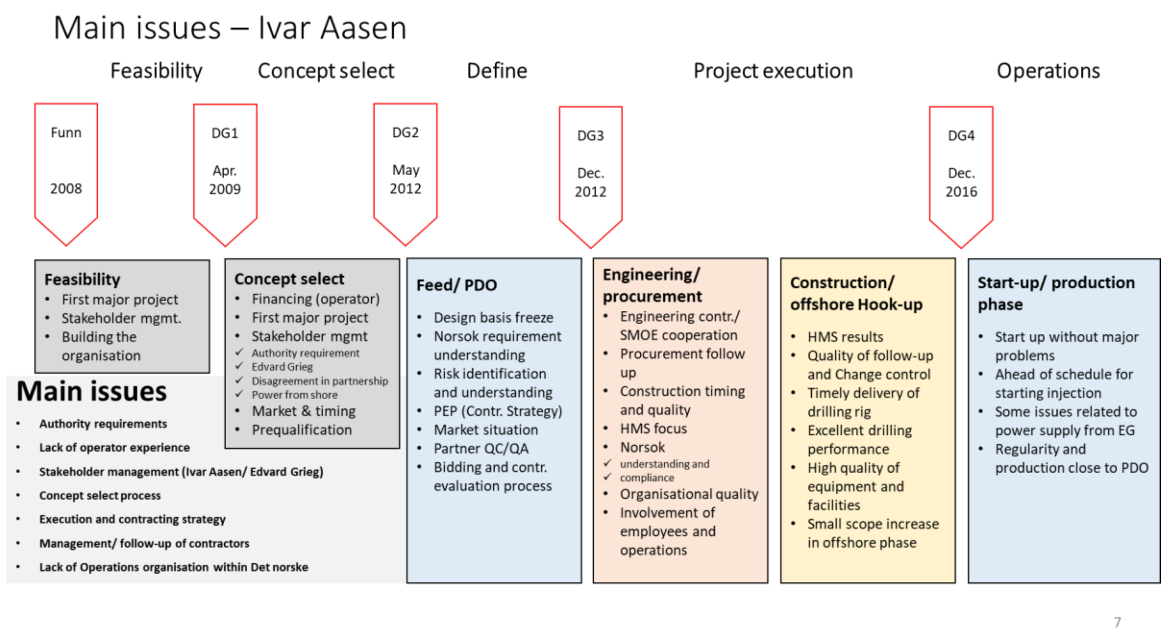


Figure 5-3. Ivar Aasen licence history and project challenges. (Source: Acona)

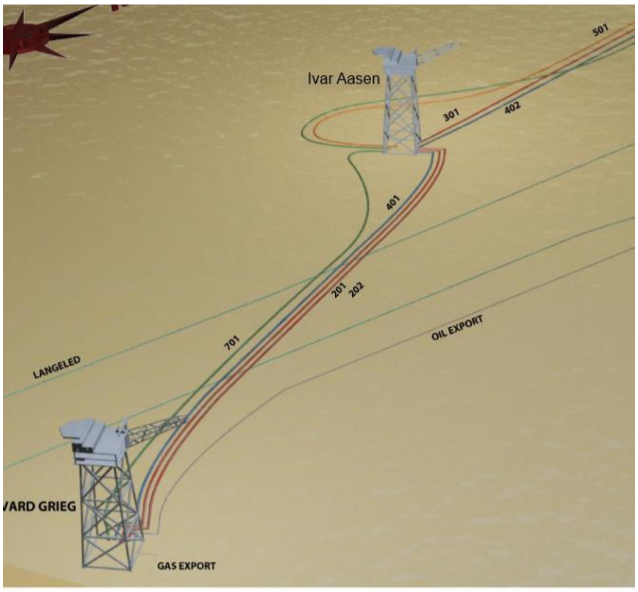


Figure 5-4. Concept solution. (Source: Aker BP)

The platform solution selected for Ivar Aasen is designated a pdQ. See Figure 5-4. The wells have been drilled with the aid of a chartered jack-up rig.

A critical factor in this type of development solution is the availability of a suitable drilling rig. A preliminary contract for Ivar Aasen was accordingly entered into with Maersk as early as December 2011 covering the hire of a new CJ-70 XLE jack-up type.

Oil and gas are separated on the Ivar Aasen platform in a one-stage process and pressurised before the product streams are mixed and transferred via two pipelines to the Edvard Grieg platform for final processing and export. Oil and gas are being transferred initially in both pipelines, but only one will be used as production declines in order to ensure sufficient flow speed to reach the specified arrival temperature on the Edvard Grieg facility. Produced water is separated out on the Ivar Aasen platform and injected together with deaereated seawater into the Ivar Aasen and Hanz reservoirs for pressure support. Sulphate in the seawater is removed before injection to prevent the deposition of barium salts in wells and production equipment. Power is provided from the Edvard Grieg platform. Figure 5-5 presents an overview of the concept.

Key data

- Jacket weight: about 8 700 tonnes.
- Topsides weight: 14 800 tonnes
- Platform wells: seven producers and six water injectors.
- Subsea wells (Hanz): one producer and one water injector.
- Design capacity: 9 000 scm/d oil, thee million scm/d gas, 21 000 scm/d liquid.
- Oil export: via Edvard Grieg.
- Gas export: via Edvard Grieg.
- Processing services: Edvard Grieg.

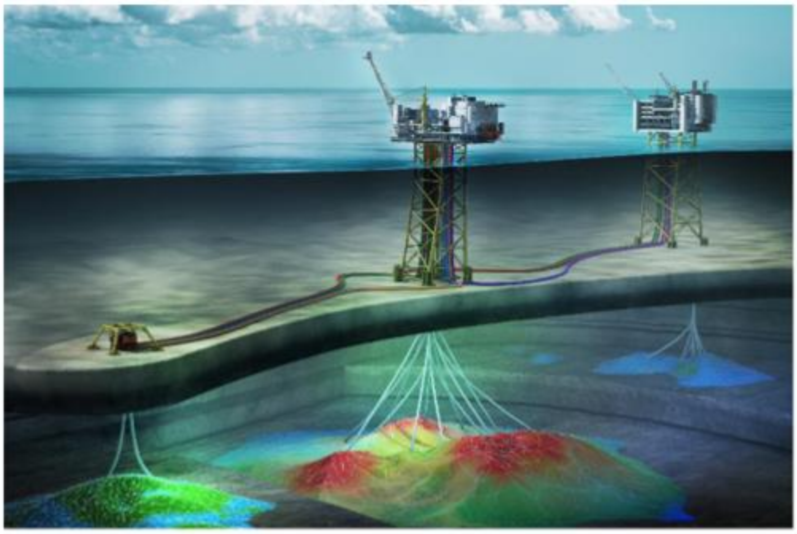


Figure 5-5. Illustration of the Ivar Aasen concept. (Source: Aker BP)

5.1.3 Development of plans and costs over the project's life

An overview of milestones and activities in the early phase is presented in Figure 5-6 and Figure 5-7.

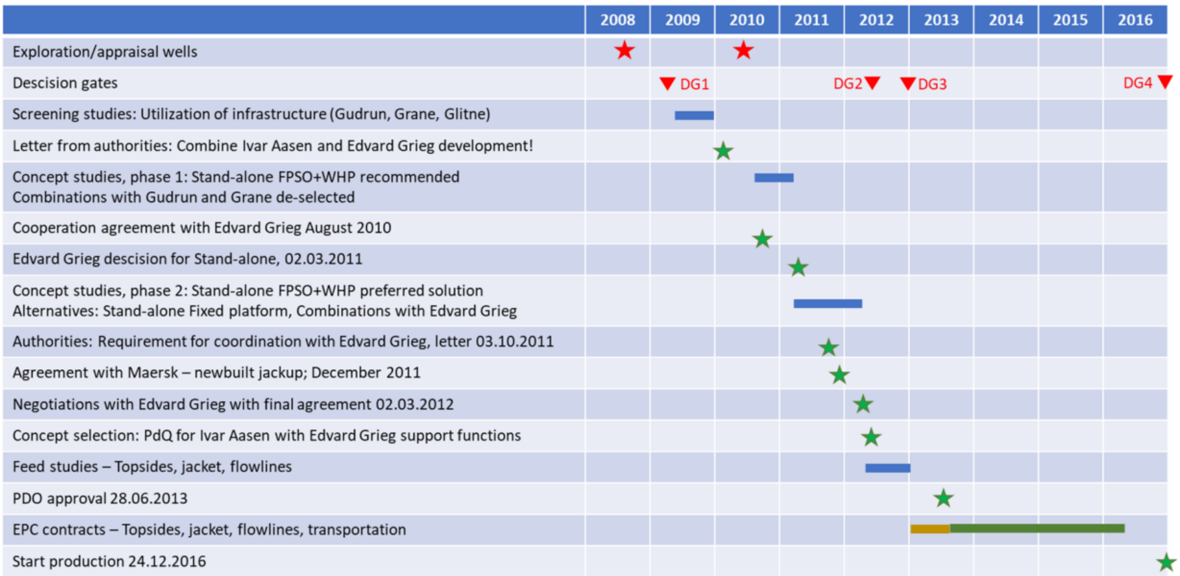


Figure 5-6. Project milestones. (Source: Acona)

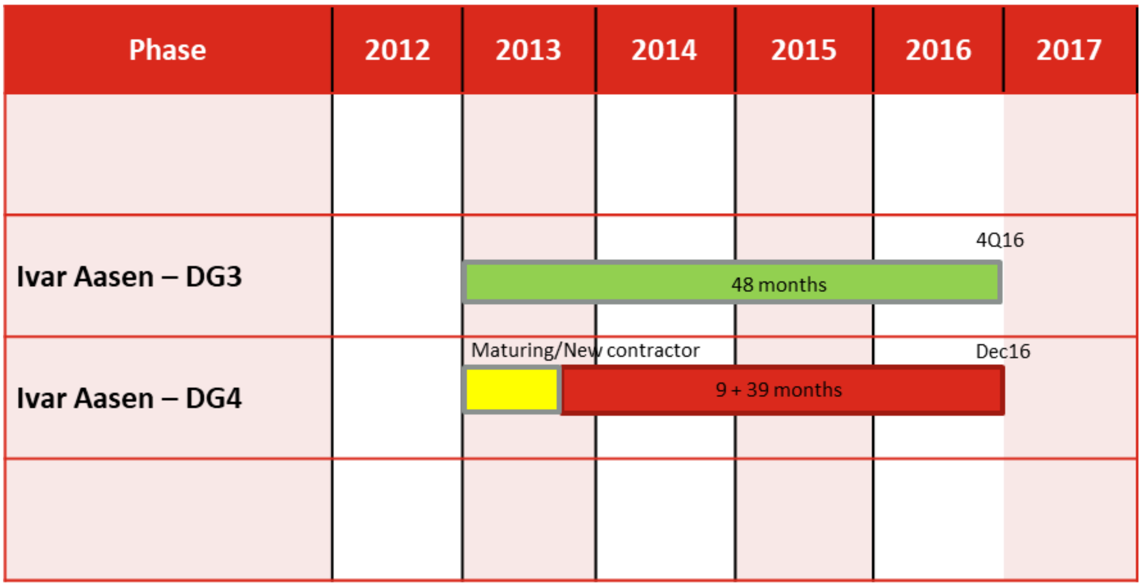
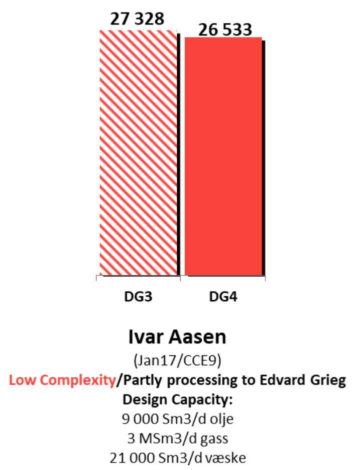


Figure 5-7. Execution – plan development. (Source: Acona)

Figure 5-8 gives an overview of the most important cost elements at DG3 and DG4. Figure 5-9 and Figure 5-10 provide a graphical presentation of changes over time for each main element in the estimate.



MNOK

	DG3	DG4	DIFF
Management	936	699	
FPSO	-	-	
Topside	6 065	9 025	+ 49%
Living Quarter	616	812	
Completion	1 113	2 566	+ 130%
Substructure	**899**	**869**	
Mooring,Offloading & Inst.	-	-	
Risers & Flowlines	-	-	
Heavy Lift and Transport.	**571**	**423**	
Extend./Remaining Scope	-	50	
Contingency	2 843	209	
Facilities – Platform	**13 043**	**14 653**	**+ 14%**
Facilities – Subsea & Pip.	1 363	1 240	
Drilling & Well	**7 774**	**5 545**	**- 29%**
Power Supply incl. Infra.	-	-	
Host	539	568	
PMT/Petek	279	297	
Preparation for Operation	850	934	
Insurance	259	197	
Adjust. (Currency impact)	-	-	
Phase 1	24 107	23 434	
Phase 2	3 221	3 099	
Total (Project Close-out)	**27 328**	**26 533**	**Jan 17**
Total (Statsbudsjettet 2019)	27 900	27 500	MNOK'17

DG3 - Total Dry weight 13 978 tonnes.   DG4 - Total Dry weight 14 835 tonnes

Note: Additional drilling scope not incl. in PDO – 851 MNOK

Figure 5-8. Capex – cost development. (Source: Acona)

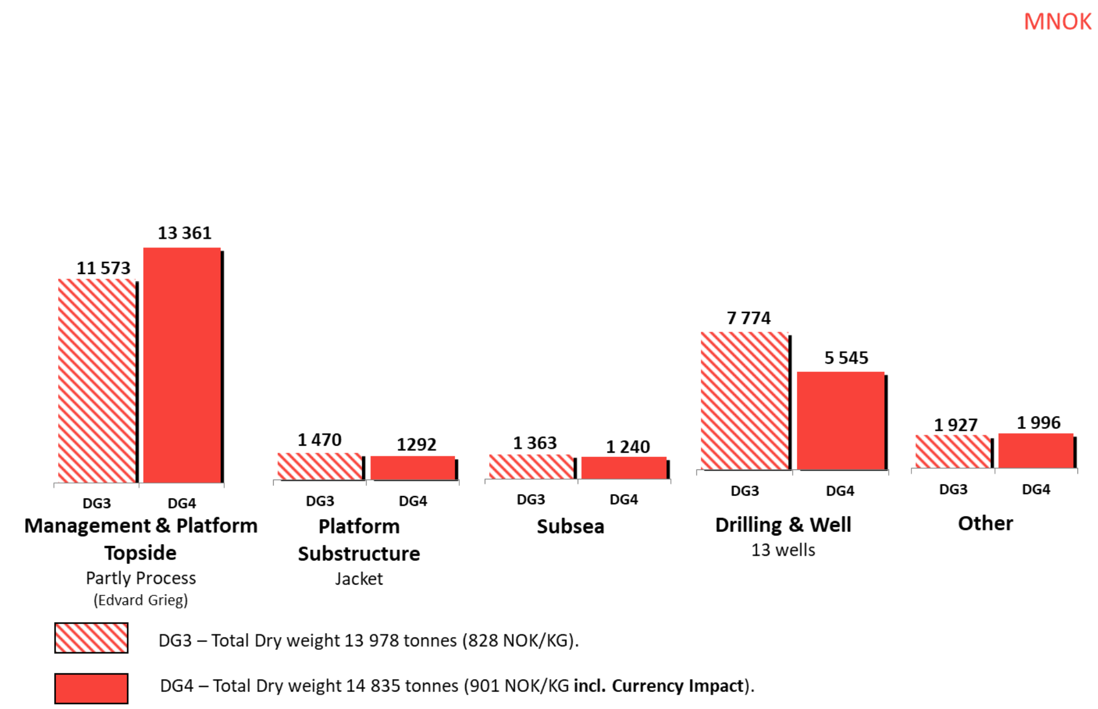


Figure 5-9. Main elements – cost development. (Source: Acona)

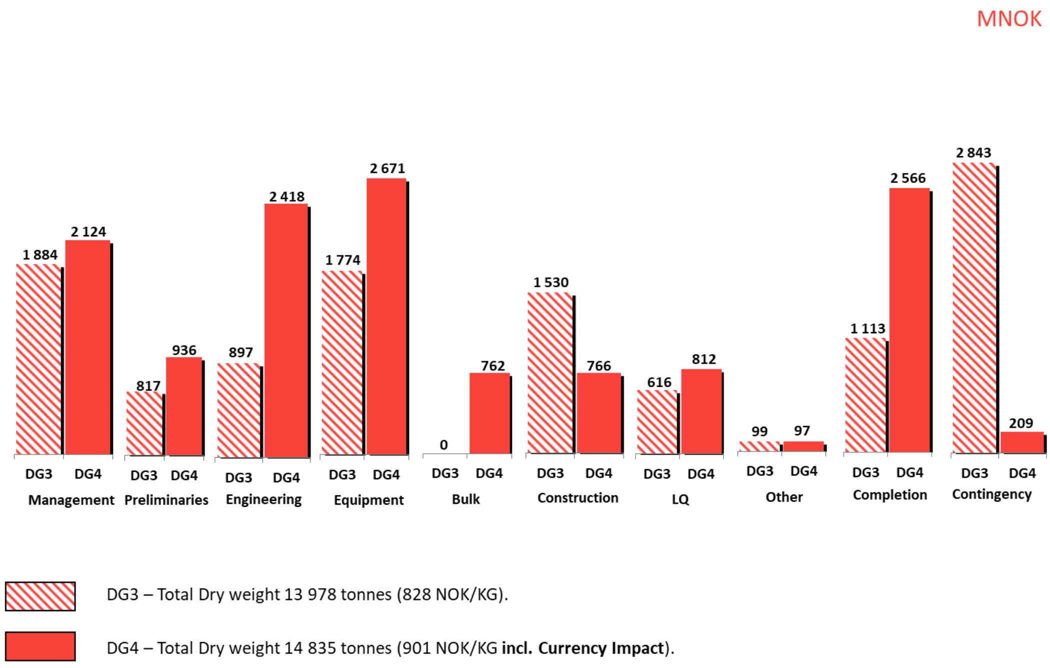


Figure 5-10. Management and topsides – cost development. (Source: Acona)

Drilling – Meters pr day (excl. core and log).

- History/experience:
  - P10 – 160 meters
  - P50 – 95 meters
  - P90 – 45 meters
- Today:
  - Ivar Aasen World Class 150-300 meters pr. day.

Completion – Total completion days.

- History/experience:
  - P10 – 12 days
  - P50 – 18 days
  - P90 – 40 days
- Today:
  - Ivar Aasen World Class 7-12 total completion days.

Figure 5-11. Drilling and well – benchmark. (Source: Rushmore)

Only minor changes were made to the plan described in the PDO during project execution. Ivar Aasen was discovered in 2008, the PDO was submitted in December 2012 and the field came on stream in December 2016. This means that the early phase took some four years and the development phase lasted four years – a total of eight years from discovery to production. That is relatively fast for a platform-based project.

According to the project's close-out report, the total cost estimate was reduced by NOK 0.8 billion – from NOK 27.3 billion at DG3 to NOK 26.5 billion at DG4. The total execution time of 48 months remained unchanged from DG3 to DG4.

Total costs for the topsides, including the operator's management/follow-up, contributed an increase of NOK 1.8 billion, while drilling and completion went much better than expected with a saving of NOK 2.2 because of a "world class" drilling speed. See Figure 5-11. Sembcorp Marine (SMOE) had poor productivity, was not compensated for all construction hours used and thereby showed a loss. The scope of work for the topsides was stable, rising from 13 978 tonnes at DG3 to 14 835 tonnes at DG4 – in other words, a weight increase of six per cent.

Engineering costs were underestimated as NOK 0.9 billion at contract award, and rose to NOK 2.4 billion by DG4. Engineering hours were estimated as one million at DG3 – in other words, relatively low compared with other projects. Poor productivity has boosted these hours to 2.4 million at DG4. Hourly rates and productivity for engineering are fairly similar worldwide.

Fabrication hours for the topsides were estimated at 2.4 million at DG3, but ended up as 10.8 million by DG4. Hourly rates and productivity for fabrication/installation vary widely around the world. Completion costs were underestimated, and rose from NOK 1.1 billion at DG3 to NOK 2.6 billion by DG4.

Total costs for the topsides, including the operator's management/follow-up, rose from NOK 11.6 billion at DG3 to NOK 13.4 billion by DG4, and the kilogram price increased from NOK 828 to NOK 901.

The project took six months to complete this simple platform offshore, which is in line with experience from similar facilities.

When the PDO was submitted, the project had a breakeven price of about USD 66/bbl. Although this was acceptable in relation to oil price expectations at the time (USD 90/bbl), it represents a high value which reflects a high level of costs. That reflects a combination of generally high costs in the industry, conservative estimating and a relatively expensive development solution compared with the reserve base. Increases in recoverable volumes have had a positive effect.

5.2 From licence award to choice of concept (DG2)

5.2.1 Discoveries and appraisals up to DG1

It was decided in the autumn of 2008 to launch studies to confirm the technical and commercial feasibility of a coordinated development of the Ivar Aasen and Hanz discoveries.

The operator presented its assessment (DG1) in the spring of 2009, and confirmed the possibility that the two discoveries could profitably be developed together. This was based on a stand-alone development and utilising existing/planned infrastructure in the area.

Enquiries were made in this period about the use of existing production facilities – the Grane field centre, the Glitne FPSO, the Balder FPSO and a planned new field centre on Gudrun. The Glitne option was dropped early because of insufficient capacity and the need for major conversion of the FPSO.

5.2.2 Feasibility studies – evaluation phase up to DG2

At DG1 for Ivar Aasen, use of infrastructure was selected as one of the options to be further matured up to DG2. Screening studies were therefore conducted in 2009 by the operators of Grane and Gudrun for tie-back to these fields. Both wellstream transfer and full processing on the host platform, and partial processing on Ivar Aasen with final processing on the host platform were considered.

An option with full processing to sales-gas export requirements was also studied. This would have meant a tie-in to Gassco's existing sales gas pipeline system. It was shelved in part because of limited robustness to varying gas and oil compositions from possible future third-party fields.

Edvard Grieg was discovered in the third quarter of 2007 – a little before Ivar Aasen. Maturing these discoveries and studying development solutions therefore proceeded in parallel. Since they are only eight to 10 kilometres apart, a coordinated development was relevant. Contact was established between the two licence groups in November 2008 with a view to investigating this approach.

Confirmation of the resources in the Ivar Aasen deposit was an important precondition for proceeding to a DG2 decision. Det Norske proposed an appraisal well as early as the spring of 2009 and had allocated a rig for this, but failed to secure sufficient partnership support. When the appraisal well was approved and drilled (spring 2010), it confirmed the operator's model and it became clear that the discovery had substantial commercial potential. About a year's progress with developing Ivar Aasen was probably lost because of this. This well provided the basis for upgrading the resources. Including West Cable in further work towards DG2 was proposed by the operator in the spring of 2010, and revealed positive incremental economics for an extended-reach well drilled from the Ivar Aasen facility.

A letter from the NPD in January 2010 told the licence groups for Ivar Aasen and Edvard Grieg to study a coordinated solution before a concept decision was taken.

The MC decided in 2010 to initiate concept studies aimed at a joint DG2 decision for Ivar Aasen, Hanz and West Cable by the end of 2010. This work also included a joint study with the Edvard Grieg group on a coordinated development with the latter discovery. This work meant displacements to the schedule.

The operator planned to choose the concept in the first quarter of 2011 and to submit the PDO in the third quarter of 2011. This schedule was substantially delayed for various reasons. Concept studies concentrated on the following three options:

- a stand-alone development of Ivar Aasen, including Hanz and West Cable
- an Ivar Aasen development tied back to existing fields/infrastructure

- a coordinated development with the neighbouring Edvard Grieg field.

After an introductory round of assessments, it was decided to continue with the following solutions in order of priority:

1. leased FPSO
2. contractor-built, licence-owned FPSO
3. PdQ with jack-up drilling
4. PDQ with drilling facilities.

Screening studies for a tie-back to Grane or Gudrun were conducted in 2009 by the operators for these fields.

After a change to Gudrun's design assumptions, it became clear that this field would first have spare capacity for Ivar Aasen some time in 2018-20. The Gudrun group also stressed that it would await the outcome of wildcat due to be drilled on the Brynhild structure in the autumn of 2010. The Ivar Aasen group concluded in the summer of 2010 that a tie-back to Gudrun was no longer a competitive option.

Where the Grane option was concerned, it was concluded in 2010 that wellstream transfer might be technically feasible but would be commercially demanding because Ivar Aasen output would displace Grane's own production. In agreement with the Grane group, a tie-back to that field's platform was shelved in the autumn of 2010 owing to uncertainty about technical and commercial feasibility.

A collaboration agreement was entered into with Edvard Grieg in August 2010. The two licence groups established both technical and commercial work groups. Lundin was given responsibility for coordinating the technical work on a coordinated development, and Det Norske for the commercial side.

The study led to a recommendation from Det Norske on a stand-alone development of Ivar Aasen with a leased FPSO, in combination with an unmanned wellhead platform. A leased FPSO came across to Det Norske as particularly favourable on financial grounds (limited access to capital). But Det Norske's financing capability was not the only reason for the recommendation of a leased FPSO. This was also felt to be more robust at the lower end of the uncertainty range for recoverable volumes and production properties, and thereby to be more financially robust. This was important because the reservoir properties after the appraisal well still had an uncertainty range in the order of +/- 30 per cent. Adjacent licences (PL 338 on 16/1-14 to the south and PL 457 on 16/1-16 in the east) drilled two more appraisal wells on the field's flanks in the autumn of 2010 and the autumn of 2012 (in other words, just before DG3) respectively. The PL 457 well, in particular, significantly reduced uncertainty, but the concept had then long been chosen and the PDO completed.

Hanz was to be developed with a subsea production unit tied back to the FPSO. Oil would be exported by shuttle tanker and gas via the Sage system in a shared pipeline from Edvard Grieg. However, this solution was not approved by the other partners because an assessment of project economics meant they preferred a licence-owned production facility.

In March 2011, the Edvard Grieg group said it had opted for a stand-alone development. This meant Ivar Aasen also made the same choice, with the operator recommending a development with a leased FPSO with purchase option. However, this solution failed to secure the necessary partnership support and a new concept study had to be conducted.

After the Gudrun and Grane were dropped and the Edvard Grieg group had chosen a stand-alone development, the Ivar Aasen operator worked along two axes:

1. developing a contractor-built, licence-owned FPSO
2. developing a PdQ with drilling from a jack-up rig.

The PdQ designation denotes a platform designed for production, drilling and quarters, but with wells drilled by a chartered jack-up so that a full drilling facility is not installed.

FPSO solutions

At that time, the supplier of geostationary FPSOs (Sevan Marine) had major financial problems and was in danger of going into liquidation. This was considered to represent an excessive risk, and this type of unit was dropped. Further work on FPSOs was therefore based on a traditional ship-shaped design.

It was clear that a ship-shaped FPSO would face some extra challenges related to the turret and swivel systems, but these were considered soluble. A modified solution based on the Knarr FPSO concept was regarded as optimal in terms of experience transfer and efficient project execution.

PdQ solutions

At the same time, concept studies were initiated to mature a PdQ platform for a stand-alone development. The work documented substantial potential in this solution compared with studies performed earlier.

Conclusions in the partnership, October 2011

The operator submitted its final recommendation for a stand-alone development concept in October 2011. Updated economic calculations showed a PdQ to be the most attractive answer, and this was chosen by the partnership as the relevant concept for a stand-alone development of Ivar Aasen if a coordinated solution with Edvard Grieg could not be achieved.

5.2.3 Input from the government – final choice of concept

As noted above, the Edvard Grieg group decided in March 2011 to develop the field on a stand-along basis with a PdQ platform. As a result, the decision was taken to go forward with a stand-alone solution for Ivar Aasen as well.

However, the government believed that possible coordination effects should be investigated in greater detail, and called the two licence groups to a meeting in June 2011. Shortly afterwards, the Ivar Aasen group received a proposal for a tie-in with Edvard Grieg. It found this proposal unattractive for technical, financial and commercial reasons.

The Edvard Grieg and Ivar Aasen groups received a letter from the MPE on 3 October 2011 which stated that the ministry would not approve PDOs for these fields unless it was established that the potential for substantial identified cost savings and coordination effects had been realised.

On that basis, the Ivar Aasen group decided to begin negotiations with the Edvard Grieg group based on the existing development solutions. The Ivar Aasen negotiating team's mandate was now to reach a solution with the Edvard Grieg group which would take the best possible care of both technical and commercial aspects in an Ivar Aasen tie-back to the Edvard Grieg platform, while simultaneously avoiding major changes to the latter with consequences for costs and schedules.

An agreement in principle on a coordinated development of Ivar Aasen and Edvard Grieg was reached on 13 January 2012. The final agreement was entered into on 2 March 2012. This negotiated result with technical solutions and commercial parameters represents the DG2 concept. The formal DG2 decision was taken in May 2012.

5.2.4 Description of the chosen concept

The selected platform solution for Ivar Aasen is a pdQ facility (partial processing, drilling without own rig, living quarters). Wells are drilled with the aid of a chartered jack-up.

A critical factor for this type of development solution is the availability of a suitable drilling rig. A preliminary contract for Ivar Aasen was accordingly entered into with Maersk as early as December 2011 covering the hire of a new CJ-70 XLE jack-up type.

Oil and gas are separated on the Ivar Aasen platform in a one-stage process and pressurised before the product streams are mixed and transferred via two pipelines to the Edvard Grieg platform for final processing and export. Oil and gas are being transferred initially in both pipelines, but only one will be used as production declines in order to ensure sufficient flow speed to reach the specified arrival temperature on the Edvard Grieg facility. Produced water is separated out on the Ivar Aasen platform and injected together with deaereated seawater into the Ivar Aasen and Hanz reservoirs for pressure support. Sulphate in the seawater is removed before injection to prevent the deposition of barium salts in wells and production equipment. Power is provided from the Edvard Grieg platform.

5.2.5 Assessment of technical safety in the concepts studied

This section addresses the actual Ivar Aasen platform – not wells or subsea facilities. It contains a brief concept description with the emphasis on aspects relating to safety. A summary is provided of the safety assessments given particular emphasis by the operator in the early phase and in the basis for the decision to implement – the PDO. The government's comments in connection with its consideration of the PDO are cited.

Ivar Aasen has a fixed jacket-supported platform. It is designated a pdQ with reference to its functions. The lower-case "p" and "d" refer respectively to the absence of full processing and absence of drilling facilities, although wells are drilled through the platform. A chartered jack-up standing alongside the platform is used for this during the drilling phase. Some of the wells on Ivar Aasen were predrilled through the template and the rest were drilled after topsides installation. This is a well-known and well-tested solution with several attractive features, but has not been used that much on the NCS because of the water depths. Relatively few jack-ups can be used in depths much beyond 100 metres. However, some larger rigs have been built in recent years which can be utilised in waters as deep as 150 metres under certain conditions

Living quarters on the platform comprise 70 single cabins. No main power generation has been installed. Electricity is delivered by cable from the Edvard Grieg platform, which also supplies Ivar Aasen with lift gas.

The platform jacket is a traditional piled steel structure, which is the most widely used support solution in the North Sea for waters less than 150 metres deep where oil can be exported by pipeline. Its four legs are piled to the seabed, and the piles have a penetration depth of about 80 metres. The platform includes four pre-installed risers along with a number of J tubes for pull-in of flowlines and umbilicals.

The topsides were constructed and installed as four separate units:

- a main module, including areas for process, wellheads and utilities
- a process module installed on top of the main unit
- a living quarters with helideck
- the flare boom.

These four units were installed on the field with the aid of a crane vessel. Measuring 76 x 75 metres, the main module is supported by the jacket at four points. The process module includes the gas compressor and sulphate removal unit and stands on the eastern end of the main unit. The living quarters and flare boom are attached to the main module. Space and weight capacities have been reserved on top of the process module for a possible future module.

The topsides are divided into four main areas as shown in Figure 5-12 and Figure 6-2, for process, wellheads, utilities and quarters. This division is intended to achieve a platform with the highest possible level of built-in safety for personnel on board by separating hazardous and non-hazardous areas. Creating the biggest possible physical division between these areas is desirable in order to prevent the escalation of accidents and exposure of personnel to risk. The quarters area includes accommodation for 70 people, the helideck, two freefall lifeboats, a man-overboard boat and a HVAC room placed beneath the living quarters.

Material handling to and from the platform is accomplished with a large platform crane installed on the south side of the topsides, between the wellhead and utilities areas. This covers all relevant areas of the topsides. Internal materials transport is largely handled by forklift trucks rather than cranes.

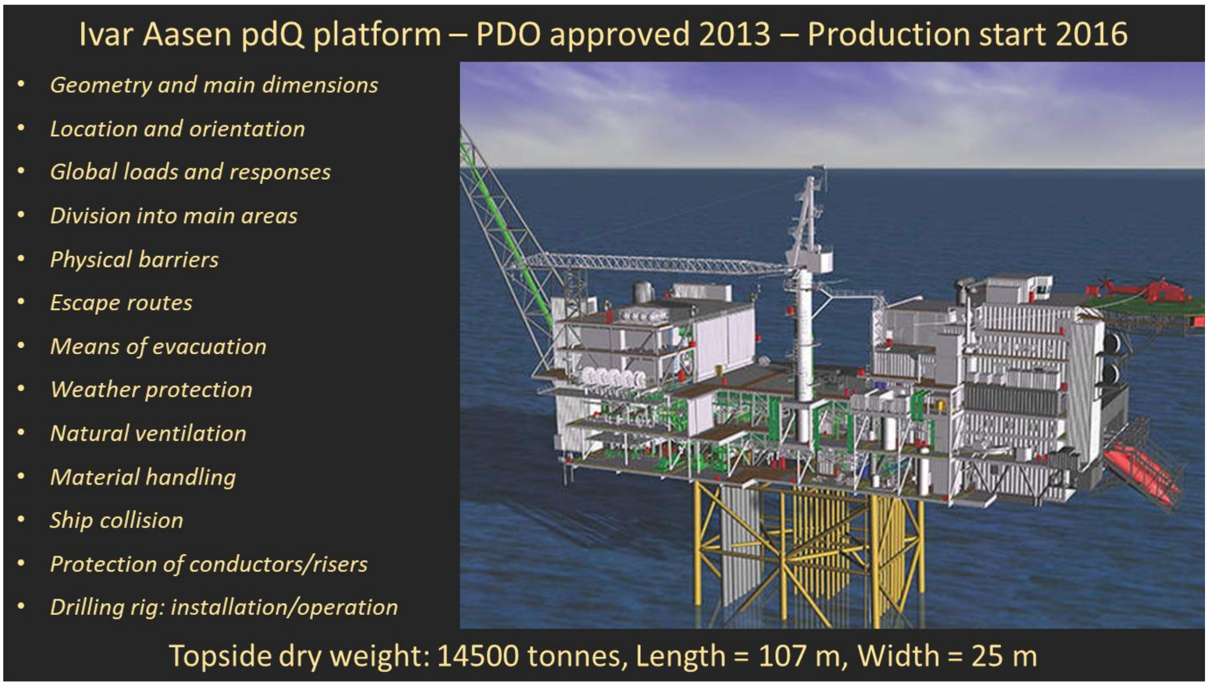


Figure 5-12. Safety-related issues assessed by the operator in the early phase. (Source: Acona)

Operator's analyses and assessment of safety

The operator gave emphasis to the following in the PDO documentation:

- eliminating risk, and identifying barriers to exposure and preventive measures
- identifying and reducing major accident risk
- reducing risk in line with the Alarp principle
- selecting solutions which reduce uncertainty in cases where knowledge is lacking.

Work was done on Hazid and to establish barriers against major accidents. A number of analyses and studies were also conducted as input to further concept development.

Where positioning and orientation of the field installations are concerned, the assessments made are outlined below.

The position of the platform was chosen after studies of possibilities for encountering shallow gas in the area, geotechnical conditions (installation/foundation of mobile drilling rig), and ship traffic.

Its orientation was selected to secure good natural ventilation and to reduce the likelihood that possible smoke or flammable gas would expose the platform's safe areas.

All risers and wells are protected within the main jacket structure, and pipelines exiting from the Ivar Aasen platform are laid eastwards under the flare to ensure adequate distance from lifting operations on platform and rig.

The following factors are significant for major accidents.

- A short distance between the mobile drilling rig and the pdQ platform will mean that incidents which threaten one will be a threat to both. That applies both to HC fires and collisions.
- Challenges were identified in relation to escape opportunities on the pdQ. Escaping from the process area to the living quarters past the wellhead area was regarded as vulnerable with incidents in the latter section. That resulted in the inclusion of an enclosed escape tunnel with overpressure protection from process to quarters.
- The pdQ jacket is dimensioned to cope with collisions by visiting vessels. But a need was identified for more detailed studies of the drilling rig's ability to withstand collision loads with an eye to both rig and pdQ, since a collapse of the former will affect the latter.

- Risers containing HC were moved to the least exposed areas of the jacket with a view to avoiding a collision by a visiting vessel.

In the documentation, the operator emphasised the importance of establishing an integrated barrier system in order to give personnel (at all levels both on land and offshore) the necessary understanding of the barrier management system's purpose, mode of operation and basic principles, which barriers exist and what they are meant to do.

5.2.6 Concept definition phase up to PDO

According to the plans for Edvard Grieg, it would have capacity to receive Ivar Aasen production from the fourth quarter of 2016. Around the end of 2011, therefore, goals and commercial contracts were established which envisaged coming on stream in the fourth quarter of 2016. This ambitious target imposed considerable pressure on the project. The tight schedule and market conditions meant that Feed work was placed in London, where Aker Solutions had just established a new department which was still in a build-up phase.

A fresh challenge arose in the final stage of work on the PDO. The geological interpretations indicated that part of the Ivar Aasen discovery extended into the neighbouring PL 457, operated by Wintershall. The licensees accordingly decided to drill an exploration well close to the licence boundary. Ivar Aasen's PDO had not reckoned with possible volumes from this licence. A discovery was made, and the NPD concluded that it was part of the Ivar Aasen deposit. Without a unitised development, the plans could not be approved. Much work was devoted to reaching agreement on the size and division of the additional resources. The parties had to undertake to present an update on resources, division of volumes and development plans by the summer of 2013.

Feed studies were conducted in 2012 on:

- topsides
- jacket
- pipelines and marine operations.

No major conceptual changes were made to the pdQ concept for Ivar Aasen after DG2. On the other hand, a certain amount of design development occurred in a number of areas.

A weight increase in the integrated topsides meant that weight margins became too small for lifting the topsides with main module in a single lift plus two smaller lifts for the living quarters and flare boom. It was therefore decided to move from a three-lift strategy to a four-lift approach, with the integrated topsides divided into two modules.

The decision basis for project execution was prepared at time when the level of activity in the petroleum sector was very high and expectations were for an oil price of USD 90/bbl. In order to ensure capacity in the supplier industry and to fix costs, it was important for the partnership to enter into a number of early contracts – in other words, before the PDO had been approved.

The PDO was submitted to the government on 21 December 2012. At that point, the project had a calculated breakeven price of USD 65.7/bbl. Although this was acceptable in relation to the prevailing oil price expectations, it represented a high breakeven which reflected a high level of costs. The project was executed within the approved budget.

Approval of the PDO was received on 28 June 2013.

In addition to the conditions for approval quoted in a separate chapter, the PSA pointed to two conditions where the solutions were not in compliance with the regulations. One related to electricity generation and firewater, while the other concerned lifeboat capacity in relation to the number of beds in the living quarters.

5.2.7 Risk understanding and worker participation

The Ivar Aasen project kicked off in the concept evaluation phase with a systematic identification of possible risks for all functions/disciplines involved, as well as external risks related to commercial contracts and stakeholders. Identified risks are considered to be relevant and realistic.

Det Norske possessed no operations organisation of its own at that point, but a number of veteran project participants had experience of making provision for efficient operation or had served in operations organisations earlier. Recruitment of operations personnel began after DG3, and the acquisition of Marathon gave the company an operations organisation of some size. Systematic involvement of the safety service also began then.

5.2.8 Government comments on the concept during PDO consideration

The following comments were made by the ASD and the PSA in connection with their consideration of the PDO:

> The PSA has identified two technical solutions which do not meet the requirements in the regulations.
>
> In the PSA's view, the technical solutions described for electricity generation and firewater supply fail to the meet the regulatory requirements. See section 5, paragraph 2 of the management regulations on barriers, and sections 47, litera h and 36, paragraph 2 of the facilities regulations on electrical installations and on firewater supply respectively. This has been raised with the operator and will be followed up further.
>
> The living quarters are dimensioned with 70 single cabins – 40 of which have reversible beds. Det Norske confirms that the maximum number of personnel on board (POB) will be 70. The chosen lifeboat solution gives a maximum POB of 70 people. The PSA considers that the planned utilisation of the living quarters with reversible beds cannot be utilised without a different lifeboat solution.
>
> It emerges from the plans that no agreement has been entered into with the neighbouring PL 457. The PSA's proviso is that no changes are made to the concept as a result of a future agreement with PL 457.
>
> The ASD refers to the PSA's assessments and has no further comments.
>
> **Conclusions and conditions**
>
> The MPE approves the plan for development and operation of Ivar Aasen in accordance with the plans presented by the operator and the observations communicated in the Proposition, and on the following conditions:
>
> 1. Final agreement on unitising resources between PLs 001 B and 457 and the division of the resources in 16/1-9 Ivar Aasen between these PLs must have been reached and submitted to the ministry by 30 June 2014.
> 2. Until final agreement on unitising resources has been reached and submitted to the ministry, the licensees in PL 001 B must regularly inform the licensees in PL 457 about updating of geoscientific and reservoir technology work, resource estimates, production strategy, and the design and location of production wells for the 16/1-9 Ivar Aasen deposit.
> 3. A plan for delineating the 16/1-9 Ivar Aasen deposit, an updated plan for producing the deposit and the basis for this plan and updated main plan for drilling and well activities must be submitted to the ministry for approval by 30 June 2014. The ministry reserves the right to set conditions for a prudent utilisation of the resources, based on the updated plans submitted.
> 4. An assessment must be made of internal communication and flow properties in the Sleipner and Skagerrak formations in order to formulate a good production strategy for these formations. Opportunities for and the possible benefit of formation/ interference tests in these formations must be included in the assessment. The assessment must be submitted to the NPD by 30 June 2014.
> 5. The licensees in the Ivar Aasen field must contribute actively to the work of studying an integrated power-from-shore solution for the southern part of the Utsira High. The licensees in the Ivar Aasen field must also meet their proportionate share of the costs of this study.
> 6. Should the ministry determine that an integrated power-from-shore solution for the southern Utsira High is to be realised, the Ivar Aasen field must be connected to such a solution unless the ministry decides otherwise for special reasons.
> 7. Should the ministry determine that an integrated power-from-shore solution for the southern Utsira High is to be realised and that the Ivar Aasen field is to be connected,

the licensees in the Ivar Aasen field must meet their proportionate share of the investment and operating costs for such a solution.

5.2.9 Contract strategies and awards

Det Norske concluded at an early stage that it had to base execution of the project on EPC contracts. This was decided because the company had neither the capacity nor the resources to carry out the EPC itself. Market conditions were also a contributory factor in the choice of EPC contracts for Ivar Aasen.

It was decided to use EPC/EPCI terms for all three of the largest deliveries – the platform topsides, the jacket and the Surf – in order to limit the number of interfaces. In addition came verification and support contracts. Hook-up and testing were merged to avoid a new interface at the end of the hook-up period. The intention was to identify good suppliers in parallel with Feed work before the PDO was delivered. This was done to ensure that the project could be implemented within the schedule.

The contracts were accordingly placed in parallel with official consideration of the PDO, and conditional on government approval of the latter. Worth NOK 7.8 billion, these assignments covered:

- drilling and well services – chartering of drilling rig
- wellheads and Xmas trees
- platform topsides
- steel jacket, signed in February 2013
- jacket transport and installation
- pipeline between Ivar Aasen and Edvard Grieg
- chartering of flotel for accommodating personnel during hook-up and commissioning of the facility.

The government made it clear that consent to award contracts would not influence its consideration of the PDO, and that the licensees would bear full responsibility for the financial risk such contracts represented – including the possibility that the government could amend or refuse to approve the PDO.

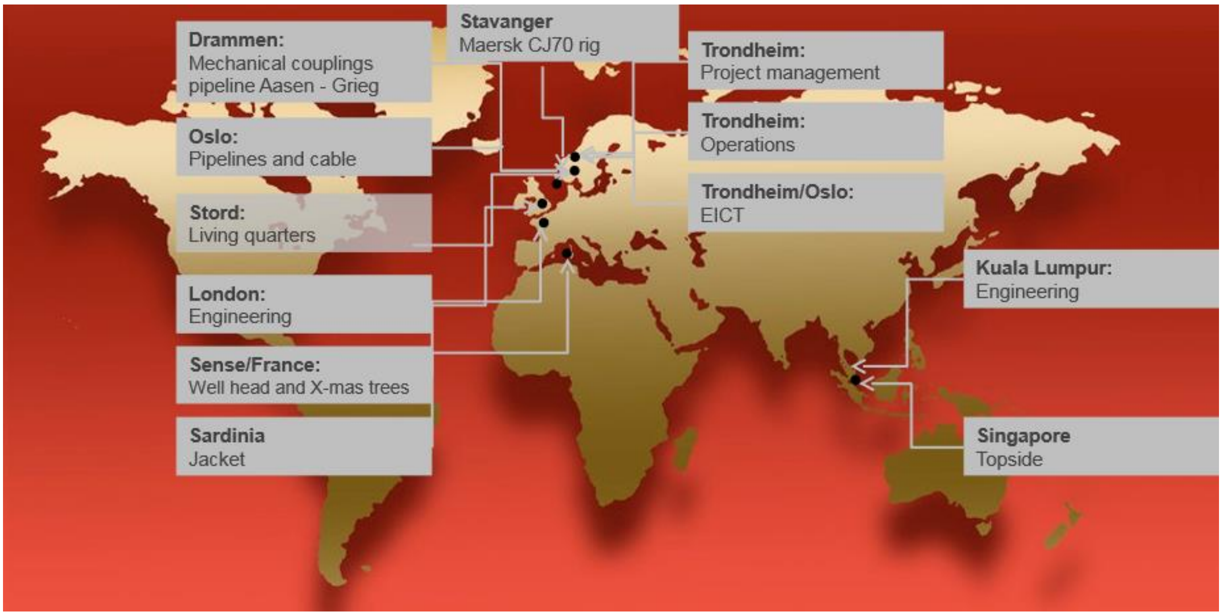


Figure 5-13. Big spread of contracts – geographically and in terms of time. (Source: Aker BP)

Topsides contract

Invitations to tender for the topsides were sent to Kværner, Samsung, SMOE, DSME, Aibel and Heerema, but the last three withdrew. The tendering team which evaluated the topsides contract believed there was little chance of meeting the target of first oil in the fourth quarter of 2016. In a memorandum to the partnership's MC, the project referred to the risk of delays. It was noted that SMOE's bid was lower than Kværner's. The operator nevertheless believed that three month's delay could change the conclusion and recommended that the contract went to Kværner. This was voted down by the partnership with reference to the evaluation criteria agreed in advance. The award to SMOE was then unanimously agreed.

The topsides was the largest contract in the Ivar Aasen project and covered several sub-deliveries – the process plant, gas compression, separation, water injection, the flare boom and metering. The EPC contract for the topsides was awarded to SMOE with Mustang as its engineering subcontractor. Construction began on schedule in December 2013 and was due to be completed in March 2016.

Jacket

The NOK 709 million contract was awarded to Saipem, with construction at Arbatax in Sardinia. Standing 138 metres high, the jacket was to be installed in 112 metres of water. Its total weight with piles is 14 400 tonnes.

Transport and installation

Worth NOK 310 million, the T&I contract was awarded to Saipem. It ensured that the topsides could be lifted onto the jacket in the time window allocated for this job in the plan. The jacket was lifted into position in July 2015, with the topsides following in July 2016. Engineering for both contracts was done in London.

EICT contract

Siemens secured the contract for a complete electrical, control and communication system on the platform. This job was awarded at the same time as the topsides went to SMOE, and was later transferred from Det Norske to SMOE.

Surf

The Surf contract for Ivar Aasen was awarded to Emas AMC, and covered project management, detail engineering, procurement, fabrication and installation. Emas AMC was also to install the submarine power cable to the neighbouring Edvard Grieg field. The contract was worth about USD 165 million.

Flotel

Prosafe secured the contract to provide a flotel, and *Safe Scandinavia* served on Ivar Aasen during completion of the platform. This contract was worth in the order of NOK 380 million.

Hook-up

In addition to hooking up the jacket, topsides and living quarters, the contract also covered installation of piping, steel, cable trays and cabling to assemble and integrate all units on the platform. This job went to Aibel. A letter of intent was also entered into on operational support, maintenance and modification assignments for the field. The agreement runs for six years, with two options for extensions of two years each.

Living quarters

Det Norske awarded the contract to build the living quarters to Apply Leirvik. This seven-storey structure provides a total floor space of 3 300 square metres. It has 70 single cabins, recreational areas, changing rooms, control room, helideck and all other facilities required to run an offshore hotel. The living quarters are built in aluminium. The contract had a fixed price of NOK 450 million, but the final cost was higher than this.

The quarters also accommodate the central control room for the field, while all HVAC equipment and utilities for the topsides are located in its cellar. There were therefore a number of interfaces with the EICT work done by Siemens.

5.3 From DG3 until the platform arrived in Norway

5.3.1 Execution of the EPC contracts

Plans for five large Norwegian development projects were approved in 2012-13. This meant that Norway was sold out for engineering, and Det Norske had to do Feed and detail design in London. That was challenging for a new and small operator company. Construction contracts for platform elements with substantial interdependencies were placed in different sites at considerable distances apart and with time differentials which made communication especially demanding. See Figure 5-13.

Particular problems were posed by the topsides contract, and the relationship between Det Norske and Aker made it even more demanding. It generated both uncertainty and delays up to the contract award to SMOE, a subsidiary of Sembcorp Marine in Singapore (SMOE was to use engineering partner Wood Group Mustang in executing the project).

The intention was to complete the design basis during the engineering phase, but this was not done. Delays also arose when the Feed work was to be transferred from Aker Solutions to Mustang. The latter lacked a complete organisation to handle the project. Resources were recruited in parallel with starting the engineering work. The combination of time pressures, inadequate Feed work, an immature engineering organisation and the fact that the latter was in an establishment phase created turbulence in the ranks. The project lagged behind the production schedule for drawings. Construction work was started too early, which meant that engineering came under even greater pressure. The project struggled to get the different discipline teams to function together in the organisation.

Substantial delays were reported during 2014, but SMOE managed to get back on track through effective measures – including adjustments to the construction method/sequence to take account of delayed equipment deliveries. Despite the Feed shortcomings, the project had relatively good control of topsides weights. See Figure 5-14.

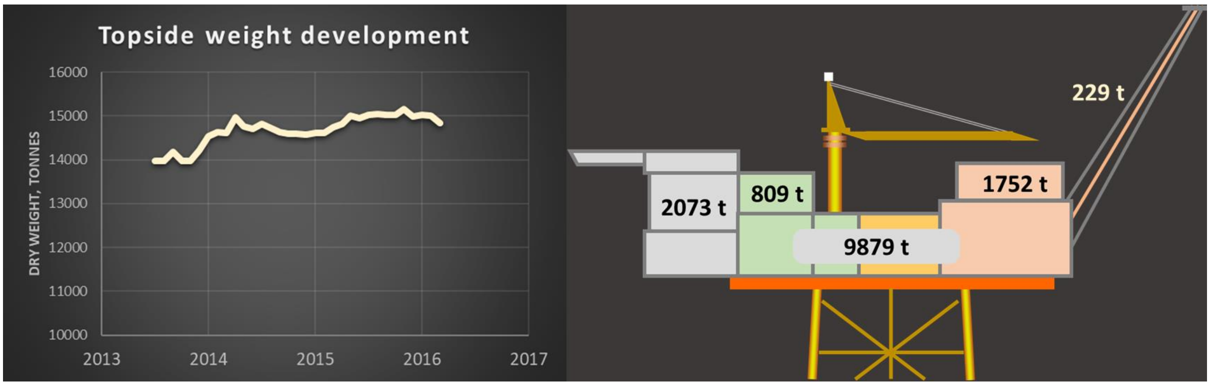


Figure 5-14. Dry weight development for the topsides. (Source: Acona)

Dry weight increased from 13 980 tonnes at Feed to 14 800 after completion – an increase of six per cent. Topsides dry weight provides the basis for cost calculations and is an important figure for weight reporting and control. Normal practice is to divide it between equipment weights, bulk weights per discipline and construction steel. Weight composition varies from platform to platform, but a marked deviation from the average should be investigated in more detail.

Figure 5-15a presents discipline weights in relation to equipment weights. Weights for the Ivar Aasen topsides are compared with average values for 16 different platforms (reference). Figure 5-15b presents discipline weights as a percentage of total dry weight for Ivar Aasen and for the reference projects.

What can be read from the figure is that Ivar Aasen deviated little from the average for the reference projects. The proportion of construction steel is on the high side, which could reflect the elongated deck configuration with big overhangs.

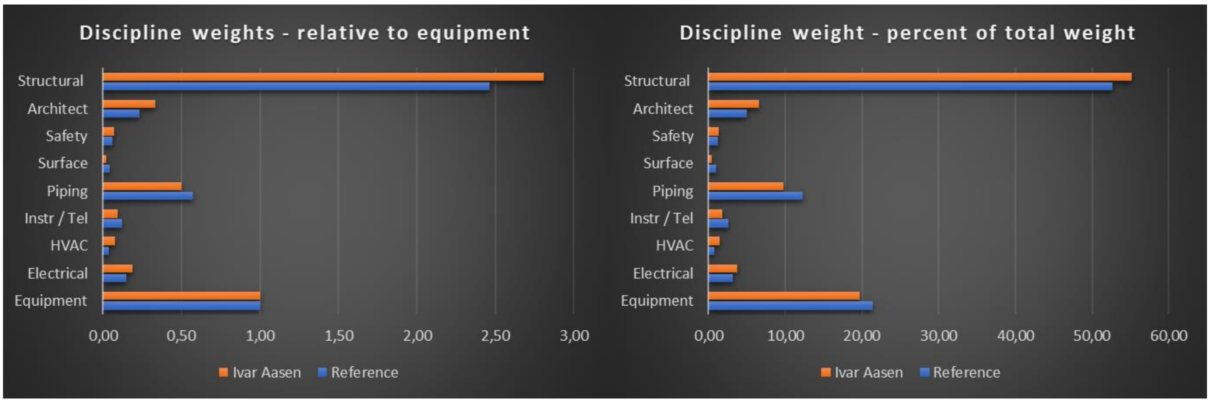


Figure 5-15. Analysis of discipline weights. (Source: Acona)

5.3.2 Platform EPC contractor's ability to accept turnkey responsibility

The EPC contractor was insufficiently prepared for Norsok – in other words, its Norsok understanding was inadequate to begin with. This improved over time through active efforts on the part of the project.

SMOE failed to follow up equipment procurement well enough, and Det Norske took over real management of procurement for the topsides at an early stage – particularly for the European suppliers, since the schedule for these was critical. Package follow-up demands surprisingly substantial resources to achieve good quality at the right time and cost. That applies to follow-up of both Norwegian and foreign suppliers.

Weak progress with detail engineering meant expected cost increases were reported right from the start of the contract.

A limited number of construction studies had been conducted in advance and manning was low to begin with, so that delays occurred immediately after kick-off. Productivity was also poorer than expected, which meant that the estimate of about six million hours ended up at 10.8 million. SMOE was not fully compensated for its costs.

Active use was made of risk management and follow-up with actions in order to reduce/ prevent risk. Det Norske's follow-up organisation was therefore substantially strengthened. At the same time, the operator succeeded in establishing a close and trusting collaboration with SMOE, whereby the two discharged EPC responsibilities in an integrated way.

5.3.3 HSE at the construction sites

The Ivar Aasen project's overall assessment of project risk suggested that neither the chosen technical solutions nor the project size would pose any special risk to successful execution. On the other hand, the operator's experience, the project organisation's size and presumed expertise, and the choice of contract strategy were regarded as sources of uncertainty. These uncertainties did not suggest that specific subjects needed extra attention from the regulator, but possible challenges attributable to the potential weaknesses would be revealed through engineering quality, possible delays and cost increases. The 15 PSA audits of engineering, fabrication and production to date have thereby covered a wide range of subjects. Both nonconformities and improvement points have been identified in a number of these audits, but follow-up audits have dealt only with the working environment, materials handling/logistics and emergency preparedness. This means Det Norske's project organisation has understood the identified deficiencies and weaknesses, and has rapidly implemented or described acceptable corrective solutions.

Of the three developments assessed in this study, the Ivar Aasen project has attracted the fewest audits. Its execution time was also the shortest. Since the PSA has not found follow-up audits necessary along the way and the subjects covered span such a wide range, it can be concluded that Det Norske's project team had a good overview and control at all times, and was able to handle challenges which arose quickly and appropriately.

5.4 Drilling and well operations

5.4.1 Reservoir understanding and well planning

The D&W and Petec functions in the project demonstrated an effective approach to "one team" thinking. Integrated teams were established and good routines developed for knowledge sharing with the suppliers.

Good communication, understanding of the organic interdependencies and coordination between D&W and Petec have contributed to Ivar Aasen's success. Petec identifies and determines where D&W is to place the wells for optimum oil recovery. For technical and geological reasons, interdependencies between these two sub-projects were complicated. Both therefore recognised the importance of showing an understanding of each other's standpoints and of striking the right balance. That called for close communication during planning and execution, with the suppliers also closely involved in the process.

This mutual interdependence was also emphasised, practically and visually, because D&W and Petec sat together in the office landscape, with their managers next to each other.

5.4.2 Choice of drilling concept

A preliminary contract for Ivar Aasen was entered into with Maersk as early as December 2011 covering the hire of a new CJ-70 XLE jack-up type.

5.4.3 Drilling and well operations

Drilling and well operations were conducted very efficiently. Days taken for drilling and completion were reduced by almost 500 compared with the PDO estimates. The total cost saving came to NOK 2.2 billion, or almost 30 per cent of the overall budget for D&W activities. Virtually all the wells on Ivar Aasen are within the P10 area of the Rushmore index, the most respected benchmark index for drilling and completion.

5.5 Offshore hook-up and completion

5.5.1 Marine installations and completion

The project completed this simple platform offshore in a total of six months, which is in line with experience from similar facilities

5.5.2 Commissioning and handover to operations

No special problems beyond those normally encountered were reported from this phase.

5.6 Production phase from start-up to the spring of 2019

5.6.1 Production preparations and readying for start-up

Det Norske possessed no operations organisation of its own when the development began, but had personnel with production experience and also received assistance from the biggest partner, Equinor. Marathon's Norwegian operations were incorporated in Det Norske during June 2014, giving it a large operative operations organisation in-house from that point.

Cooperation between the project and the operations department built up appears to have functioned well ("one team" thinking). A number of personnel from the project phase also transferred to the production stage, with good knowledge transfer and continuity.

Despite the early-phase problems with pressure of time, Feed quality and coordination challenges, the field came on stream as planned in the fourth quarter of 2016 with a rapid production build-up and good regularity.

5.6.2 On stream – regularity, HSE and safe platform operation

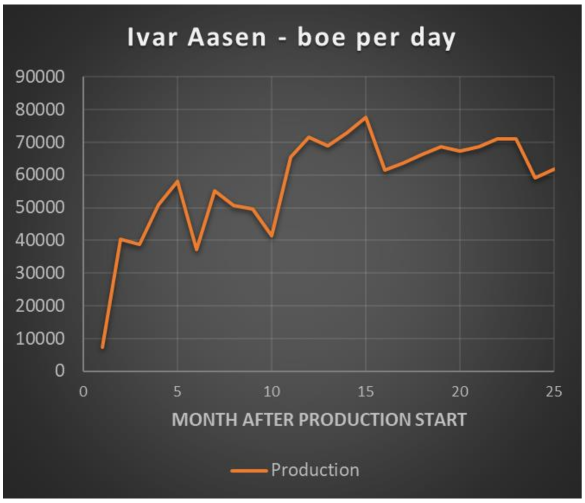
The Ivar Aasen platform came on stream on 24 December 2016, and several modifications have already been implemented since then. The biggest is perhaps the implementation of remote control of the platform. In late 2018, operation was transferred to the new onshore control centre in Trondheim.

A dedicated audit was conducted by the PSA before the control room on land was taken into use to verify that the solution is prudent and accords with regulatory requirements. This audit resulted in one nonconformity in the technical solution for the onshore control room as well as a number of improvement points related to the clarity of important documentation for safety and emergency preparedness. Ivar Aasen has taken the new control room solution into use, which means that the identified nonconformities and improvement points have found a satisfactory solution.

About 15 incidents have been notified for Ivar Aasen from the start of production until this study started (just over 20 months on stream). These incidents concern ships on a collision course, overfilling of tanks with subsequent leaks when bunkering diesel oil, overheating of electrical cables, equipment faults causing personal injuries, and dropped/rotating objects during material handling. Viewing incidents from the production period in relation to those which occurred during offshore completion, however, dropped or swinging objects/loads stand out as the most frequent type of incident. Loads swinging over an area which should be unaffected by lifting operations must be attributed to the design. During interviews with Aker BP personnel, it emerged that challenges were faced in achieving a good design for materials handling. The fact that a number of solutions fall well short of optimal was discovered relatively late in the project, and it thereby became difficult to change the design to fully optimal solutions. The incident referred to here shows that it is important to keep a critical eye on the choice of or lack of barriers, even after the handover process has been completed.

The incidents involving dropped objects display a couple of main features. Objects have repeatedly "slipped out" or been dropped as personnel move from one place to another. That an object can be dropped shows that it was not properly secured to start with. Another aspect of the "dropped object" category involves what can be attributed to lack of tidiness in the workplace. Such incidents must be prevented through awareness-raising and work on attitudes, activities which must be pursued continuously.

Ivar Aasen came on stream on 24 December 2016. During 2017, its first production year, it produced 19.1 million barrels of oe or 3.04 million scm. Output was stepped up quickly in line with the processing agreement with Edvard Grieg. As Figure 5-16 shows, accumulated production lies close to the figure anticipated in the PDO. Production reached capacity in October 2017, which means plateau output was achieved earlier than planned. Water injection began in May.



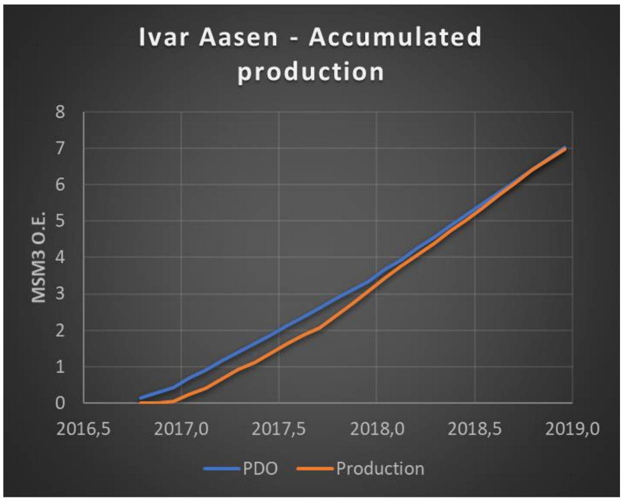


Figure 5-16. Production since 24 December 2016 compared with the PDO. (Source: Acona)

The *Maersk Interceptor* drilling rig left the field in August. Drilling and well operations were delivered about twice as fast as planned, and rig time was reduced by 500 days compared with the PDO. This is attributed to modern technology and good integration of the platform and land organisations with the aid of modern communication systems.

5.6.3 Status for the project in the second quarter of 2019

Ivar Aasen is in stable operation with good regularity and acceptable HSE results. The Aker BP organisation is still in a restructuring and consolidation phase, where systems and operating procedures from three former operations organisations (BP, Marathon and Det Norske) are being coordinated and integrated.

At the same time, the control room function for Ivar Aasen has been moved ashore, and a good deal of modification work is also under way on board. So far, the organisation appears to be tackling the high pace of change in a good way

5.7 Operator’s organisation, partner follow-up and government

5.7.1 Project organisation and manning

The project organisation was built up in parallel with maturing the project. Since the bulk of the workforce was recruited externally or hired as consultants, it took time before the organisation found its final form. The organisational charts below (Figure 5-17 and Figure 5-18) are from the fourth quarter of 2013 and are more or less identical with the Equinor approach to project organisation.

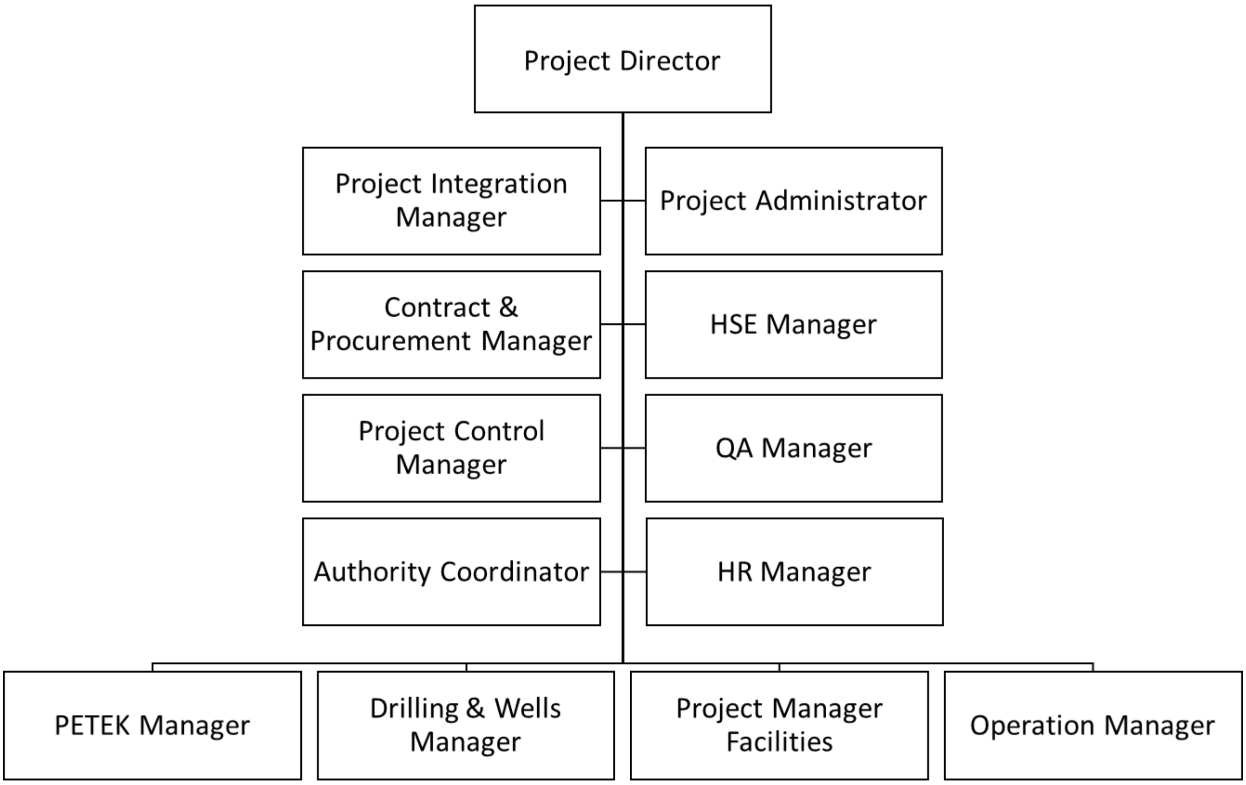


Figure 5-17. Organisation chart for the overall Ivar Aasen project. (Source: Aker BP)

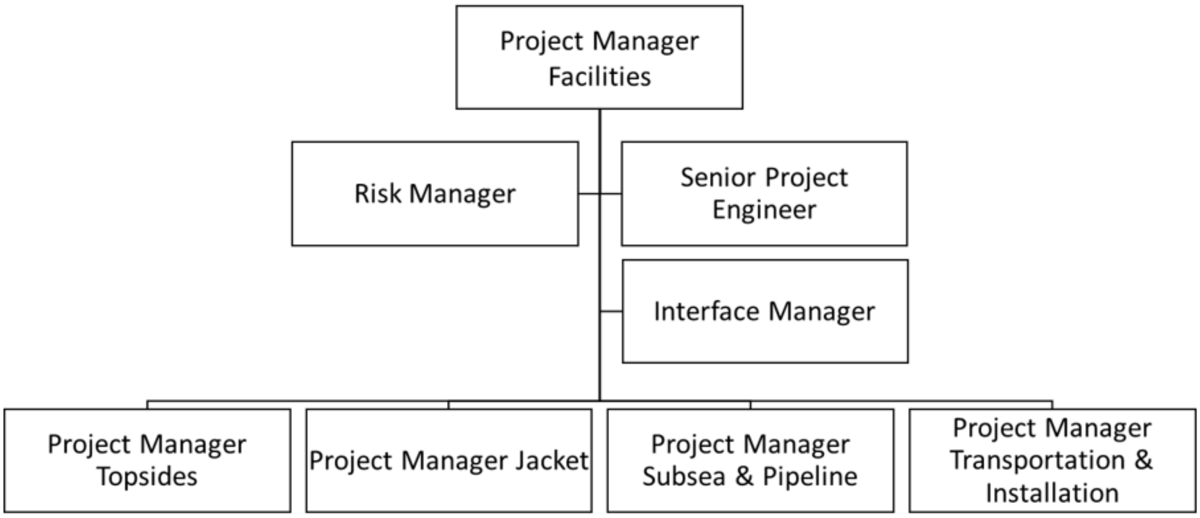


Figure 5-18. Organisation chart for the Ivar Aasen development project. (Source: Aker BP)

The project had an internal project owner, who succeeded in concentrating attention on its most important elements. That is very helpful when various issues need to be prioritised. Dedication and decisiveness in solving the problems which quickly arose have also been an important success factor.

Interfaces between the various sub-projects and with Edvard Grieg created a number of challenges along the way.

Risk management was used as an important tool from the start, and it can be seen from the summaries prepared for the MC that risks were by and large identified in good time before problems arose. This improved preparedness for dealing with them.

5.7.2 Partners' role and involvement

The partnership on Ivar Aasen was demanding in the early phases because the biggest licensee, Statoil, had a veto.

Both Lundin and Det Norske, as operators for Edvard Grieg and Ivar Aasen respectively, were pursuing their first field developments in this capacity, and being able to demonstrate sure and successful implementation was important for them. Coordinating the two projects was introduced as a government requirement. At that time, both projects were well into the planning stage and the level of activity was high. Both companies were worried that faults could arise at the interfaces, with new complications and thereby delayed production as the result.

When a contract strategy came to be established, Statoil gave emphasis to earlier experience and knowledge of similar work at the yards. HSE results were also given weight, as was the need for this to be an important/priority project for SMOE. But "engineering/procurement" and "management/follow-up" capabilities at the yard had not been adequately checked. Statoil supported giving the contract to SMOE on the basis of experience and price, with Kværner somewhat more expensive. The operator recommended the latter, but was voted down in the licence.

Equinor transferred much experience/expertise from its projects, governing documentation, training, support and so forth. The operator's organisation was willing to learn and keen to succeed, and therefore accepted all experience transfer with open arms. It can be mentioned that all Ivar Aasen's offshore installation managers had been seconded to Statoil facilities before taking up their jobs.

Since the final choice of concept/DG2, Statoil (Equinor) has set an example as a constructive partner. The operator gives it part of the credit for the project being as successful as it was. The other partners were more anonymous.

5.7.3 The government's role

The NPD was active and well involved with the operator in the early phase. On the other hand, Aker BP personnel report that the PSA showed little willingness to become involved in the project before the choice of concept was made.

In interviews, the PSA describes Det Norske's team as eager to discuss regulatory requirements and solutions and says that it relatively often made contact through informal channels to discuss specific issues. The PSA is not in a position to provide extensive informal and undocumented assistance at the detail level, and therefore had to set certain restrictions on such communication. For their part, operator personnel said in interviews that they perceived PSA staff as able and interested, and would have liked to see more of them during project execution – particularly when the project was being run from London.

Of the three developments assessed in this study, the Ivar Aasen project has attracted the fewest audits. Its execution time was also the shortest. Since the PSA has not found follow-up audits necessary along the way and the subjects covered span such a wide range, it can be concluded that Det Norske's project team had a good overview and control at all times, and was able to handle challenges which arose quickly and appropriately.

Ivar Aasen and Edvard Grieg are only eight to 10 kilometres apart. Both fields are medium-sized, and the NPD saw that coordinating them offered a potential to increase value creation. It therefore wrote to the licensees in January 2010 with a request that they study a coordination before choosing concepts, and an expectation that the licences were in contact and exchanging information in connection with that work. The operators submitted separate reports in March 2011. These show that a coordinated solution could add value. In a meeting at the MPE in June 2011, all the licensees confirmed that possible added value was offered by a coordination. The demand for coordination from the government was thereby justified by the two operators' own work as well as by statements from the other licensees, and the companies agreed to a coordination at this meeting.

The final formal letter from the MPE concerning coordination was sent to the licensees on 3 October 2011, and specified that the PDOs for the relevant fields would not be approved unless it was established that the potential for substantial identified cost savings and the coordination effects had been realised. An agreement in principle on a coordinated development of Ivar Aasen and Edvard Grieg was finally negotiated in January 2012.

The government's desire to see a coordination in this area is both understandable and correct. According to the operator's personnel, the biggest problem with this process was that it took place in two rounds and therefore caused some delay to the schedule. However, the result was an acceptable solution, although several of those interviewed for the study believe there had been solutions which were even a little better.

5.8 Learning points

The starting point and parameters for Ivar Aasen can be summarised as follows:

- moderate reservoir complexity and uncertainty
- medium-sized project in terms of capacity and platform installations
- non-complex production installation
- marginal commerciality at the start (PDO)
- opportunities for increased activity through further exploration in the area
- known surroundings/moderate water depth
- nearby infrastructure
- traditional platform solution
- no technology qualification
- new operator (NCS and internationally)
- EPC with execution in Singapore
- realistic plan/roomy budget.

Quick execution. Ivar Aasen was discovered in 2008, the PDO was submitted in December 2012 and the field came on stream in December 2016. This means that the early phase took some four years and the development phase lasted four years – a total of eight years from discovery to production. That is relatively fast for a platform-based project.

Early phase with imposed choice of concept. The early phase followed a traditional course with feasibility, screening and concept studies plus Feed. The range of solutions studied was also fairly traditional. However, Det Norske failed to win acceptance for its proposals in the partnership or with the government, and ultimately had a solution "forced" on it which assumed a certain integration with Edvard Grieg and collaboration with Lundin.

Demanding collaboration. Relations with Edvard Grieg and operator Lundin were challenging. Lundin and Det Norske were in the same position. Both were pursuing their first big project as operator, and being able to demonstrate successful project execution was important. Coordinating the two projects was a government requirement. At that time, both projects were well into the planning stage and the level of activity was high. Both companies were worried that faults could arise at the interfaces, with new complications and thereby delayed production as the result.

Choice of concept process. Ivar Aasen was the project based to the greatest extent on known technology and tested solutions. A challenge related to choice of concept was that the drilling rig had to be secured early, before DG2. The choice of concept process for Ivar Aasen was otherwise characterised by disagreement in the partnership as well as the government's desire for coordination with Edvard Grieg. This clearly illustrates the importance of all the stakeholders getting involved and agreeing on plans at critical milestones. Agreement should preferably be reached at choice of concept. The project nevertheless ended up with an acceptable concept compromise despite later external proposals on power from shore and coordination with Edvard Grieg.

Pressure of time. As a result of the "imposed" coordination with Edvard Grieg, put in place at the end of 2011, a goal was set to come on stream in the fourth quarter of 2016. To achieve that, the project had to be mobilised and kicked off as soon as possible. Pressure of time and market conditions meant Feed work was placed in London, where Aker Solutions had just established a new department which was still in a build-up phase.

After PDO submission and in parallel with its consideration, NOK 7.8 billion in contracts conditional on government PDO approval were entered into. Preparations for these contracts were pursued to some extent in parallel with Feed work. Available time was short, and the quality of the work varied. Lack of Feed quality necessitated increasing/intensifying follow-up in the execution phase.

Known technology. Avoiding the development of new technology if acceptable conventional technical solutions are available to choose from is a wise choice for a new operator.

Development. Plans for five large Norwegian development projects were approved in 2012-13. That was challenging for a new and small operator company. Construction contracts for platform elements with substantial interdependence were placed in different sites at considerable distances apart and with time differentials which made communication especially demanding. Particular problems were posed by the topsides contract and the relationship between Det Norske and Aker made it even more demanding, generating both uncertainty and delays up to contract award.

The contract with SMOE was delayed from the start, and engineering work lagged behind – also because of an immature Feed. Substantial delays were reported during 2014 but SMOE managed to get back on track through effective measures, including adjustments to the construction method/sequence to take account of delayed equipment deliveries.

High costs. At PDO submission, the project had a calculated breakeven price of USD 65.7/bbl. Although this was acceptable in relation to prevailing oil price expectations, it represented a high breakeven which reflected a high level of costs. This probably reflected a combination of the generally high cost level in the industry, conservative estimating and an expensive development solution in relation to the reserve base. The operator's original recommended concept has significantly more robust economics in relation to the reserve base and the uncertainty this presented.

Proactive collaboration with EPC contractor. The way Det Norske managed to collaborate closely and in an integrated way with its most important contractors undoubtedly helped the project to reach its goal in a good manner. The project was able to take the right measures when the engineering process was threatening to destroy the whole execution of the project. It "took over" procurement follow-up on behalf of the EPC contractor and got it under control in terms of both planning and quality for this part of the project. (Costs, on the other hand, increased by almost 50 per cent compared with the budget.)

On stream. Despite of the deficiencies in Feed and a tight execution plan, the field came on stream in late 2016. The last six months of readying for production were characterised by good planning and control. Rapid production build-up and good regularity are indications that the pressure of time had not affected quality and safety. Drilling and well operations appear to have been particularly successful.

Project execution. As mentioned above, the choice of concept attracted big discussions and much disagreement. In retrospect, the development can be said to have been executed in accordance with approved plans and schedules. Production has developed well, and regularity is an indication of good quality. At the same time, the concept is claimed to be sub-optimal. Two reasons are cited for this.

- The dependence on Edvard Grieg is a challenge with regard to production control, capacity utilisation and regularity (dependence on electricity from Edvard Grieg has been problematic).
- the concept is expensive in relation to the reserve base, which yields a high breakeven price. A higher degree of coordination between Ivar Aasen and Edvard Grieg, with only one field centre, could have been beneficial for society.

One team. Building one team from the first day appears to have been among the most important factors behind the success on Ivar Aasen. This can be challenging when a lot of the personnel are recruited from external environments. On the other hand, however, Ivar Aasen was by far the biggest and most important activity in Det Norske (company maker) when the project kicked off. That makes it easier to set clear goals and ambitions which the whole company knows and can support.

Integrated collaboration in the operator organisation. The integrated collaboration between D&W and Petec can be highlighted as a good example of close and successful cooperation between departments, but also with the external suppliers. This yielded good results.

Supplier collaboration. Making provision for close collaboration between the suppliers is important. This can only be achieved by establishing an open and trusting dialogue and a form of collaboration based on give-and-take. Construction of the topsides, the jacket and the living quarters are all examples of this.

Good working environment. According to the project, the working environment is based on trust and mutual back-up when difficult challenges are to be tackled. Management's willingness to take decisions also supported the mood of an organisation which gets things done, and where it is therefore enjoyable to work.

6 Lessons learnt from the three projects

6.1 Technical maturation and quality

6.1.1 New solutions versus standardisation

Oil and gas fields on the NCS have been developed with many different types of platforms, which are primarily divided between fixed and floating, including ship-shaped facilities.

New solutions are adopted when operating parameters require, or when they are considered to be an improvement in relation to the criteria which form the basis for concept choice.

However, experience shows that the full potential of a new concept is not achieved on its first application. (Reference can be made to experience both off Norway and internationally, including the Gulf of Mexico.) It is only after two-three repetitions that solutions converge towards what can be called best practice. That reflects a gradual development, improvement and refinement of design standards, analysis methods, structural details, and construction and installation methods.

When a development is based on a new concept, allowance must be made for unexpected problems in all the areas mentioned above – in other words, interpretation and application of standards, analysis methods, structural details, and construction and installation methods. The result will typically be delays, increased time pressure and higher costs.

Risk can be reduced to a certain extent by particularly thorough preparations and studies, but relevant experience data (such as on productivity) will always be lacking.

Ivar Aasen. The most widely used platform concept both on the NCS and globally is a fixed structure with a steel jacket. Ivar Aasen's facility is this type. Where such platforms are concerned, a well-developed practice exists in all areas – design standards, analyses, structural details, and construction and installation methods. Good and relevant experience data exist on weights, productivity, time used and so forth.

The biggest variation is found in the topsides, which must be lifted into place offshore. To reduce the scope of offshore work, minimising the number of lifts is desirable. For small platforms, the whole topsides can be built as one module and positioned by a single lift. Larger topsides require fabrication/installation studies to identify an optimal division.

Goliat and Aasta Hansteen. Where deeper waters are concerned, fixed platforms become either too expensive or technically unfeasible. Floaters are used on such fields. These vary in their properties both with regard to opportunities for integrated oil/condensate storage and for pulling in umbilicals and risers – aspects often significant for concept choice.

As outlined in the previous chapters, Eni opted for a circular geostationary platform with a shallow draught (Sevan) for Goliat while Equinor chose a circular geostationary platform with a deep draught (Spar) for Aasta Hansteen. Both concepts were in use internationally, but not off Norway, and both became substantially larger than their predecessors. This meant that neither design standards nor analysis, construction or installation methods were developed and refined to the same level as for fixed platforms.

Hull design and construction are recognised to have proved more complicated than expected for both projects. The topsides for Aasta Hansteen were designed in accordance with known principles and were constructed and installed without major problems. Where Goliat is concerned, a special topsides design was tailored to the hull but with insufficient attention paid to fabrication. This solution proved to be construction-unfriendly and contributed to the project getting out of control.

6.1.2 Technology qualification

Continuous research into and development of new technology take place in the petroleum industry. This is necessary both to meet challenges in new areas and to permit the adoption of solutions which are better for HSE, resource utilisation and economics. At the same time, an understanding prevails that new technology represents an extra risk factor of significance for time, costs and safety. Such innovations can include new products or analysis tools, or known products used in a new way.

Good criteria are required for developing, testing and adopting new technology. They must be representative of the relevant conditions of use, and the technology or methods must be tailored to existing solutions. Plans for technology qualification and for using alternative technology must be realistic in order to avoid delays. Where NCS operations are concerned, the document DNV-RP-A203 *Qualification Procedures for New Technology* is used in planning.

A substantial technology transition was implemented on the NCS in the late 1990s, particularly with regard to floating production facilities and subsea installations with wells. This created uncertainties which were inadequately addressed in budgeting and project execution, as highlighted in *Analyse av investeringsutviklingen på kontinentalsokkelen 1999*. Since 2000, new technology has been introduced more gradually and under better control. According to *Vurdering av gjennomførte prosjekter på norsk sokkel 2013*, new technological elements appear to be well handled in the projects.

With a few exceptions, the Goliat, Aasta Hansteen and Ivar Aasen projects used solutions based on known technology. The Sevan and Spar concepts, for Goliat and Aasta Hansteen respectively, were new on the NCS but known from a number of applications elsewhere.

Where Goliat is concerned, the new technology elements related to wellheads and the well workover system, mooring, oil offloading and the submarine power cable. With Aasta Hansteen, new technology elements were identified in relation to the Spar concept, risers and mooring systems, the gas turbine for the compressor, SSIVs and the well workover system. No technology qualification was required for Ivar Aasen.

None of the projects experienced significant problems with new technology. This was partly because these elements were limited and well defined, but also because the companies had good plans and paid sufficient attention to technology qualification. Goliat and Aasta Hansteen ran into delays for other reasons, which may have contributed to ensuring that technology qualification was problem-free.

6.1.3 Main topsides layout

Most platforms on the NCS are multifunctional – in other words, facilities which combine areas for processing, wellheads, drilling, risers, utilities, quarters, lifeboats and helicopters. See Figure 6-1. Such platforms operate with large quantities of flammable liquids, explosive gases under high pressure and heavy machinery, all positioned in small areas and often combined with living quarters. This requires safety considerations and systems to be included early in the planning phase. Although major accidents are infrequent statistically, the preconditions for their occurrence are constantly present.

An important goal is to prevent accidents escalating, so that personnel beyond the immediate vicinity of the accident site are not harmed. Load-bearing structures must continue to function until evacuation has been completed.

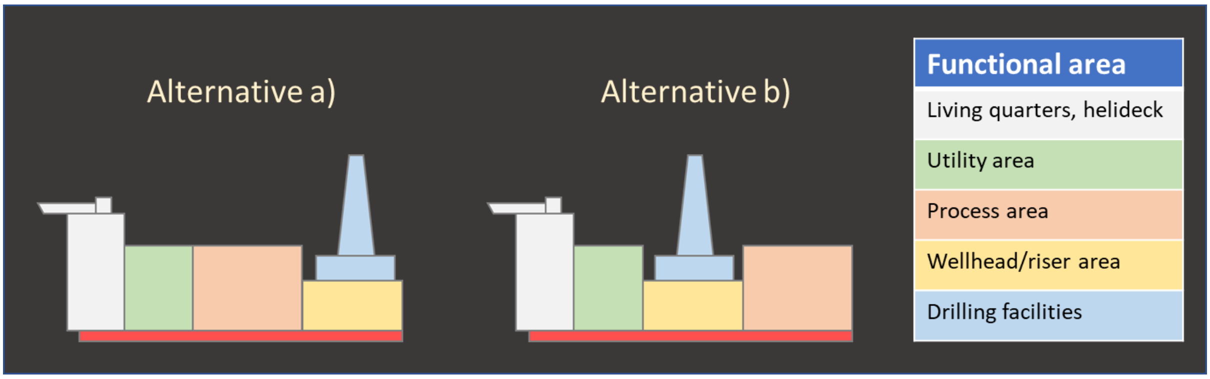


Figure 6-1. Functional areas on integrated platforms. (Source: Acona)

Main areas

Safety considerations make it appropriate to divide a topsides into main areas separated by fire/explosion-proof barriers or enough physical distance to prevent escalation. Depending on whether they are defined as main areas, these sectors must have an equipment placement and layout which contribute to good inherent safety properties and reduce risk associated with potential hazards and accidents. In many cases, such divisions will also be appropriate in construction terms. Main areas will sometimes correspond to modules which can be built in parallel at different yards.

Spaces which are significant for combating accidents must be positioned as safely as possible – in other words, in quarters or utility areas – and safe areas must remain intact until the platform has been evacuated. At least one escape route must be provided from each area where personnel can stay until evacuation of the safe areas and rescue of personnel are completed.

Utilities and transport routes must be designed for efficient and prudent materials handling and personnel traffic. Materials must be handled as far as possible by mechanical systems and technical aids

The choice of platform support structure is significant because its geometry guides and restricts topsides layout. Moreover, stability and motion characteristics must be taken into account on floaters. Some concepts include an integrated oil store and system for offshore loading of crude. These elements have a big impact on safety.

Protecting wells and risers against external loads, such as ship collisions and drifting/ dropped objects, must be assessed. Wells and risers may have to be positioned behind large structural elements or dedicated protective shielding to minimise risk.

Examples of solutions, specific requirements and recommendations

The wellhead area has generally been regarded as the most hazardous. The ideal approach is therefore to use separate wellhead platforms, but the additional cost of such structures cannot be justified in most developments by the risk reduction achieved through a solution of this kind. Multifunctional platforms are therefore the norm on the NCS.

On such installations, the wellhead area is usually placed as far as possible from the living quarters and areas with emergency equipment and functions, and is separated from utilities and process areas to reduce the consequences of a blowout. It should also be positioned so that external support for firefighting is possible.

The less hazardous utilities area is intended to function as a barrier between Ex areas and the living quarters. Ensuring good access to areas and equipment is important for achieving efficient manual firefighting, both from the platform and through external support.

As little HC piping as possible should be led to or through utilities areas, and flanges must be avoided. One flange connection can be placed in each fuel line to internal combustion engines in the utilities area. HC piping cannot be led into the quarters. Nor may liquid piping of any kind be led through electricity, instrument and control rooms. Passage of HC piping into emergency equipment areas must be restricted to supply lines for diesel engines powering emergency equipment in the area. Where passive fire protection is used, it must be designed so that relevant structures and equipment have adequate fire resistance in relation to their load-bearing capacity.

No specific rule determines how the main functional areas should be laid out, since the overall risk picture for each facility will determine the optimal solution. Nevertheless, a couple of standardised solutions have developed on the NCS. See Figure 6-1.

a) This is the most widely used solution. The drilling and well area (or the riser area) lie as far as possible from the quarters area, on the basis of assessments that this is a zone with a high risk of fire/explosion. This layout also offers practical advantages relating, for example, to materials handling and an external contribution to firefighting. The utilities area provides a buffer zone between the quarters and process areas.

b) This solution is used in the Sleipner A and Troll A gas platforms. They have large gas processing and export capacity – in other words, possess a high fire/explosion risk associated with gas treatment. A priority for these installations was to ensure the largest possible distance between the quarters area and the area for gas treatment and the gas export risers. The utilities area lies as a buffer zone between the quarters and the drilling and well area.

Comments on Goliat, Aasta Hansteen and Ivar Aasen

As described in other chapters, Goliat, Ivar Aasen and Aasta Hansteen are based on three different concepts:

- Goliat: floating buoy with shallow draught – circular cylindrical construction – Sevan design
- Ivar Aasen: conventional fixed steel jacket
- Aasta Hansteen: buoy with deep draught – circular cylindrical construction with truss structure at bottom – Spar design – truss Spar.

The Ivar Aasen concept is the commonest platform design both on the NCS and internationally.

Goliat's concept has been used for various applications internationally, but this is the first time it has been applied to the NCS and is also clearly the largest platform of its type.

The Aasta Hansteen concept has been used internationally, largely in the Gulf of Mexico, but this is its first application on the NCS and it ranks moreover as the largest platform of its kind. Unlike earlier Spar platforms, it has integrated condensate storage.

Of these three, only Ivar Aasen has a wellhead area (the two other have only subsea wells). None of the platforms have permanent drilling facilities, but a chartered drilling rig linked by a gangway to the production platform is used on Ivar Aasen.

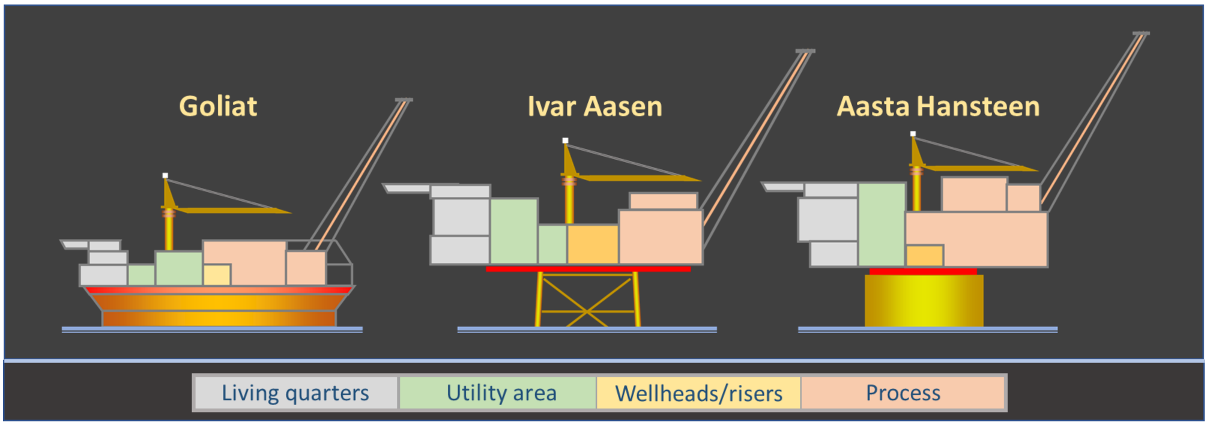


Figure 6-2. Area division on Goliat, Ivar Aasen and Aasta Hansteen. (Source: Acona)

Design of the topsides is governed by the type of support structure and considerations of construction, operation and safety. See Figure 6-2. Very different construction methods were used for the three projects:

- Aasta Hansteen: an integrated topsides ready-built as a single unit and mated at shore with the aid of barges
- Ivar Aasen: a topsides assembled from large modules lifted into place offshore
- Goliat: a topsides comprising a large number of small modules and sections lifted into place at the yard.

Nevertheless, the division into main areas with fire/explosion barriers and physical distance to prevent escalation is by and large the same on the three platforms. The review has shown that handling of safety in the early phase by and large utilised the same methodology, regardless of operator and development solutions. This shows that the principles and methodology enshrined in regulatory requirements and standards are well understood and implemented in the industry.

6.1.4 Application of safety principles in the planning phase

This section deals with safety in the early phase – systematics and definitions.

Apart from new geographical areas for two of them, none of the projects basically faced any special safety challenges related to the relevant functional requirements. The facilities were neither particularly large nor complex. This section does not address conditions which are largely dealt with during project execution and production – in other words:

- detail engineering of safety-critical systems
- procurement of equipment
- installation and completion of equipment/systems
- quality control at every level.

Work processes

Engineering in the early phase is a complex multidisciplinary process involving parallel activities and iterations leading to a concept solution which forms the basis for detail engineering, construction and installation. The challenge lies in achieving a balance between topsides area, volume, weight and load-bearing capacity while requirements for HSE are also met.

Figure 6-3 illustrates how large a proportion of the overall quantity of early-phase documentation is generated per discipline to each DG. Naturally enough, the process and mechanical disciplines have a proportionately large commitment early on, while others – such as piping and automation – come later. That varies from project to project, but the figure is intended to be representatives for the projects covered by this study.

Once functionality and the main process are defined, efforts are concentrated on geometry and layout, the main structures and heavy equipment with a long working life.

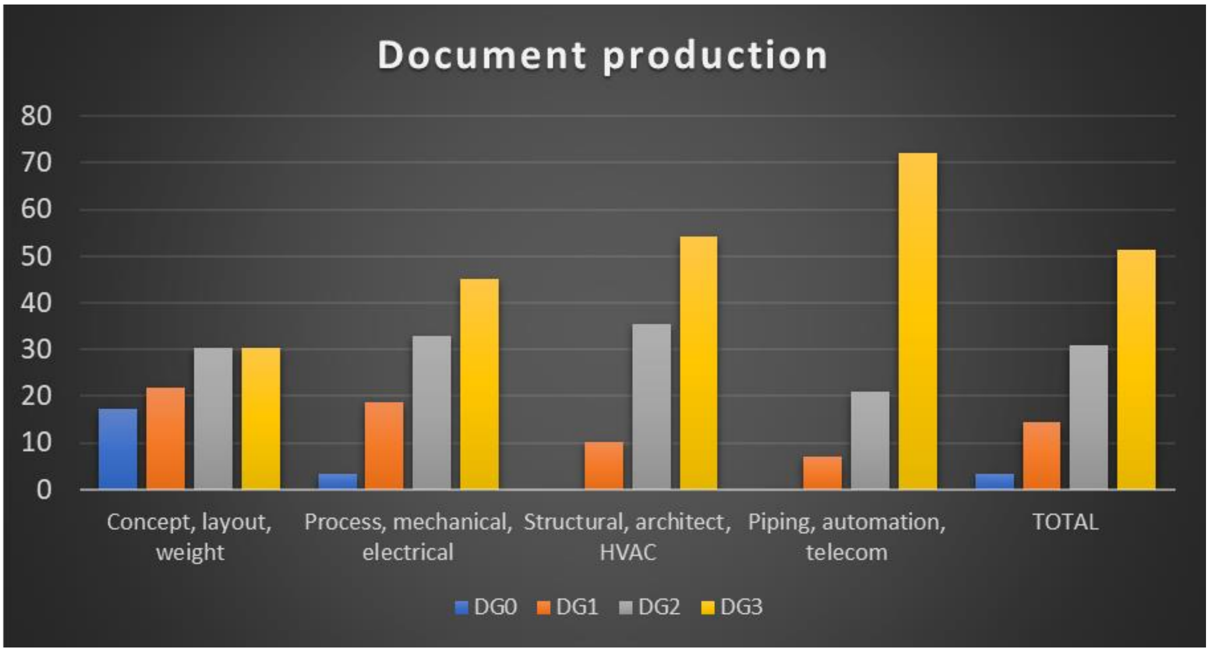


Figure 6-3. Production of early-phase documents per discipline. (Source: Acona)

Important concepts in safety work

Experience from the petroleum sector has clearly demonstrated the risk associated with this industry. The major accident perspective will therefore always be the top government priority. See *Alexander L Kielland* (1980) and Piper Alpha (1988). Some of the concepts generally used are illustrated in Figure 6-4.

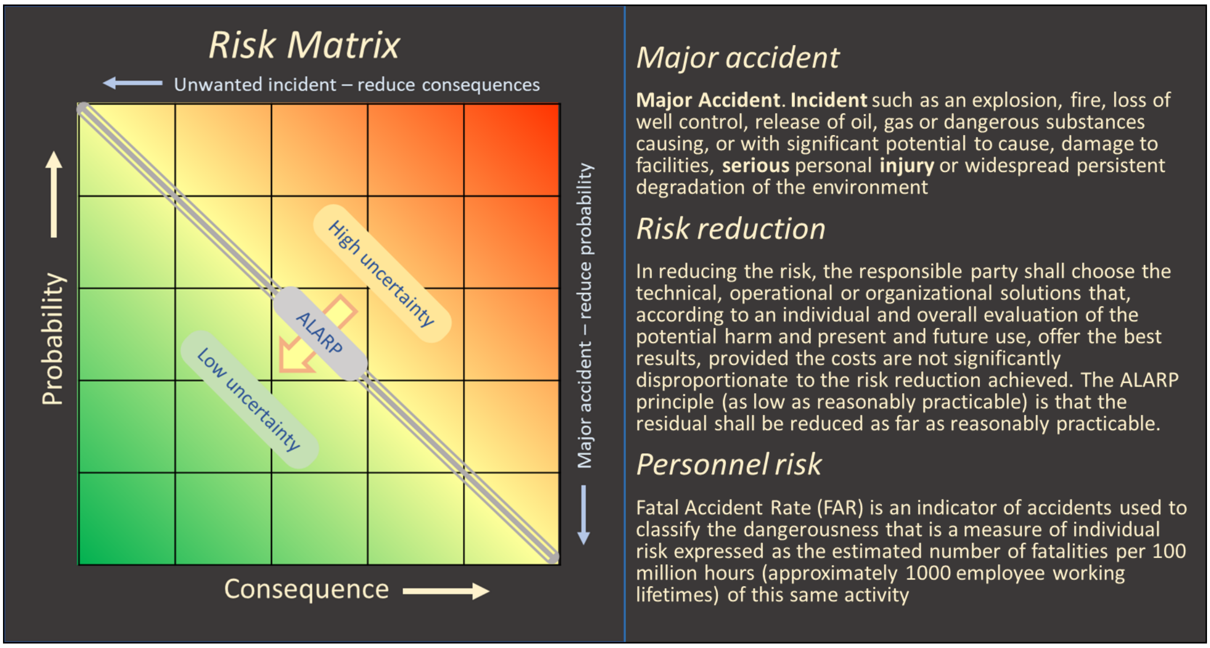


Figure 6-4. Illustration of important concepts in safety work. (Source: Acona)

Risk matrices are much used to express various risk conditions as a product of the probability and consequences of incidents. Where incidents have major consequences but low probability, however, it must be emphasised that quantifying the probability involves such great uncertainty that it becomes difficult to apply these matrices in a decision-making context. The PSA therefore clarifies the risk concept by saying that risk is the consequences of an activity with associated uncertainty

Emphasis is accordingly give to platforms being uncomplicated and robust, with the lowest possible risk of major accidents. Individual errors/faults must not lead to unacceptable consequences. This is referred to as built-in or inherent safety.

When documenting that HSE risk satisfies an established minimum requirement, further risk reduction must be pursued in accordance with the Alarp principle. This means that risk-reducing measures must be introduced unless they disproportionate in terms of cost and other associated drawbacks.

The FAR is widely used as a risk parameter. This is a statistical expected value for the number of fatalities per 100 million hours of exposure – which corresponds roughly to a whole working life for 1 000 people in all.

Main safety functions

Platforms are dimensioned for functional loads created by the physical existence, use and treatment of the installation, for natural loads derived from by natural conditions and accidental loads which the platform could be subjected to through incorrect use, technical failure or undesirable external effects.

An important goal is to prevent accidents from escalating, so that personnel outside the immediate vicinity of the accident site escape injury. Load-bearing structures must continue to function until evacuation has been completed.

Floating platforms are dependent on reliable ballast systems for maintaining their correct draught, stability and hull strength during normal use. The ballast system must also be able to restore the facility to a safe condition after an unintentional loss of buoyancy or trim, or after listing.

Spaces which are significant for combating accidents must be positioned as safely as possible – in other words, in quarters or utility areas – and safe areas must remain intact until the platform has been evacuated. At least one escape route must be provided from each area where personnel can stay until evacuation of the safe areas and rescue of personnel are completed.

Experience and analyses show that the following areas have the highest probability for major accidents. See Figure 6-5.

- HC leaks.
- Serious well incidents.
- Leaks from subsea production facilities, pipelines and associated equipment.
- Ship collisions.

Helicopter transport also has a potential for major accidents, but these are not normally categorised as such.

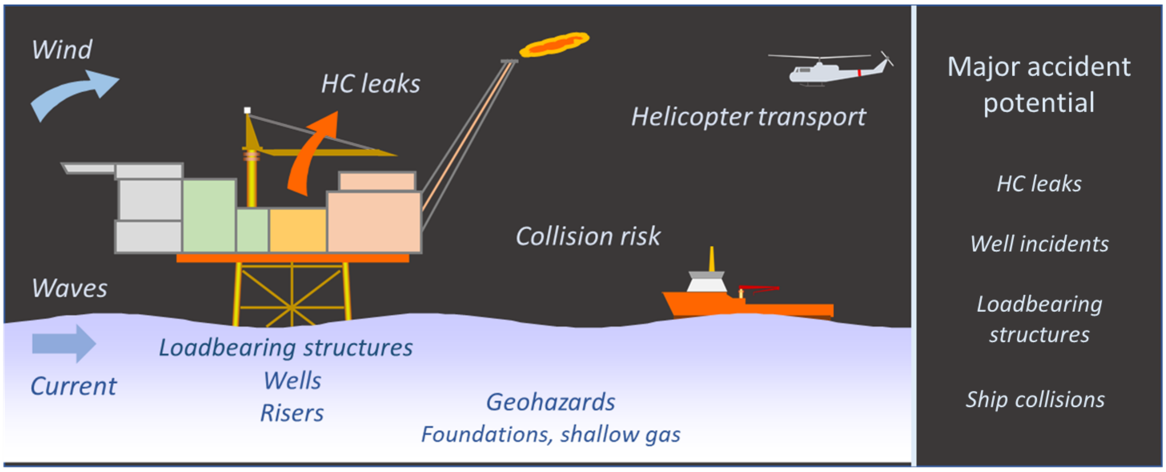


Figure 6-5. Identification and quantification of risk in the early phase. (Source: Acona)

Personnel risk expressed as an FAR value depends on the platform concept and functionality, but the most important contributions relate fairly typically to:

- process accidents
- helicopter transport
- work-related accidents
- ship collisions
- riser accidents
- dropped loads/objects.

Important safety assumptions are made as early as the choice of concept. Current design practice as enshrined in the PSA's regulations builds on recognised international and industry standards, including a number of those issued by Norsok. A developer can opt to adopt other norms and standards than those referenced in the PSA's guidelines to the regulations, but must then document specially that the safety level achieved through the use of other standards is at least as good.

The review of the Goliat, Ivar Aasen and Aasta Hansteen projects has shown that handling of safety in the early phase by and large utilised the same methodology, regardless of operator and development solutions. This shows that the principles and methodology enshrined in the regulatory requirements and standards are well understood and implemented in the industry.

All three of the projects were familiar with and applied the systematic approach developed for the NCS, and which is reflected in the regulations – PSA/Norsok. This is shown by the fact that the PSA had few comments in connection with its consideration of the PDO.

These projects have all selected concepts and solutions which facilitate good safety – even though examples exist of compromise solutions which are always open to discussion.

6.1.5 Weight control

Where platform projects are concerned, it has transpired that good project control presupposes good weight control. Weight plays an important role in connection with:

- dimensioning/weight balance
- transport and installation
- cost estimating
- stability/buoyancy/motion in operation.

Construction methods. Weight estimating is closely related to concept development and construction method. Roughly speaking, topsides classified by construction method fall into three categories.

An integrated topsides built as a complete unit which is either lifted into place on the support structure or moved over it on barges. Lifting is only possible for smaller topsides, while barges can only be used inshore. This solution has been much used with concrete platforms and several types of floater. It was utilised by Aasta Hansteen.

A large-module topsides where the modules are lifted onto the support structure. To reduce the number of lifts and minimise hook-up work, the modules are as large as possible. This solution has been much used with fixed steel jackets. Ivar Aasen is a case in point.

A topsides comprising a large number of small modules and equipment packages lifted into place. This solution is best known on land, but has also been used on production ships with large deck areas. Goliat utilised a variant of this method.

Topsides weight. The challenges of weight estimating and control apply first and foremost to the topsides. The support structure consists primarily of structural steel (or concrete), and a good overview of this can be obtained at an early phase in the project. The challenge posed by the support structure rises with the increasing degree of outfitting.

The support structure is dimensioned primarily to carry the planned topsides, often with a reserve for possible future expansion. Where floaters are concerned, topsides weight is critical for buoyancy and stability. Knowing with great accuracy where the centre of gravity lies is also necessary with such facilities. In some cases, however, the requirement for large integrated oil storage may lead to such a big support structure that topsides weight becomes less significant.

At the time the platform’s main dimensions are frozen, many details related to systems and equipment will still be unknown. Weights are estimated on the basis of preliminary design and empirical relationships. Developments in the use of three-dimensional computer aided design (CAD) have been important.

Weight optimisation. Norwegian industry has a tradition of devoting relatively substantial efforts to weight optimisation. This reflects the development of several large fields with big platforms in the first phase on the NCS (Statfjord, Gullfaks and Oseberg), where limiting weight was important. Excessive emphasis on weight optimisation in an early phase creates risk. With small margins, handling weight increases which arise during the project can be challenging and expensive. Several examples exist where additional buoyancy has had to be incorporated at a late project stage. Internationally, a stronger tradition has existed for simplifying the design process and utilising standardised structures and materials. This has yielded heavier but nevertheless cheaper solutions.

Experience from the three projects. Weight estimates from the Feed phase, which also form the basis for the PDO, represent an important parameter in describing the platform to be built and in the basis for the cost estimate. Post-PDO weight developments provide a picture of the maturity of the PDO basis and how far the operator was able to manage the project within the approved framework.

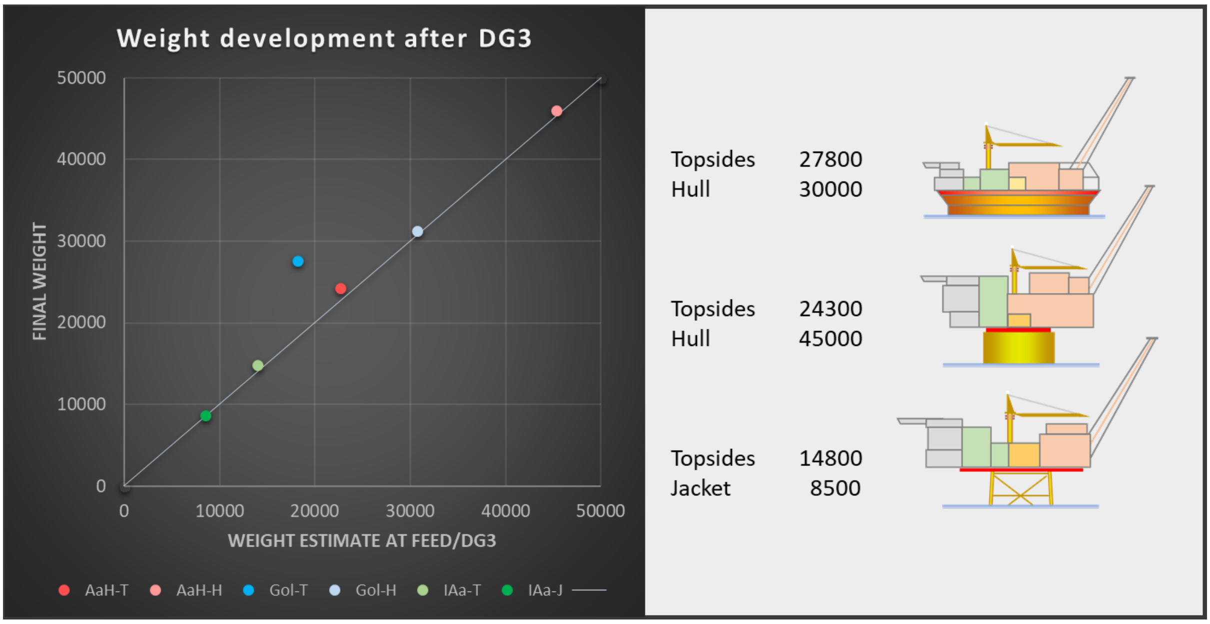


Figure 6-6. Weight of topsides and support structure – post-DG3 development. (Source: Acona)

Figure 6-6 presents the final weight in relation to the PDO estimate. Topsides and support structure are shown separately. With one qualification, the results were very good. The exception was the Goliat topsides, which is discussed in the chapter on that project. Weight here was clearly underestimated in the early phase. It was also found that HHI as fabricator had a good understanding of weights in the various disciplines and that reporting was detailed and accurate, but that the yard was conservative on unforeseen weights and little concerned to keep weight down. HHI prioritised simpler design and construction ahead of weight optimisation.

Figure 6-7a shows topsides weight progress for the three projects. The weight composition at discipline level has also been analysed for the three topsides. See Figure 6-7b.

Although all the platforms differ in functionality, capacity, concept and fabrication method, construction steel can be seen to account for 50-55 per cent of total dry weight, equipment for about 20 per cent and the other bulk disciplines for 25-30 per cent.

It is also usual to assess weight composition in relation to equipment weight. Total weight will then typically be in the order of five times the equipment weight.

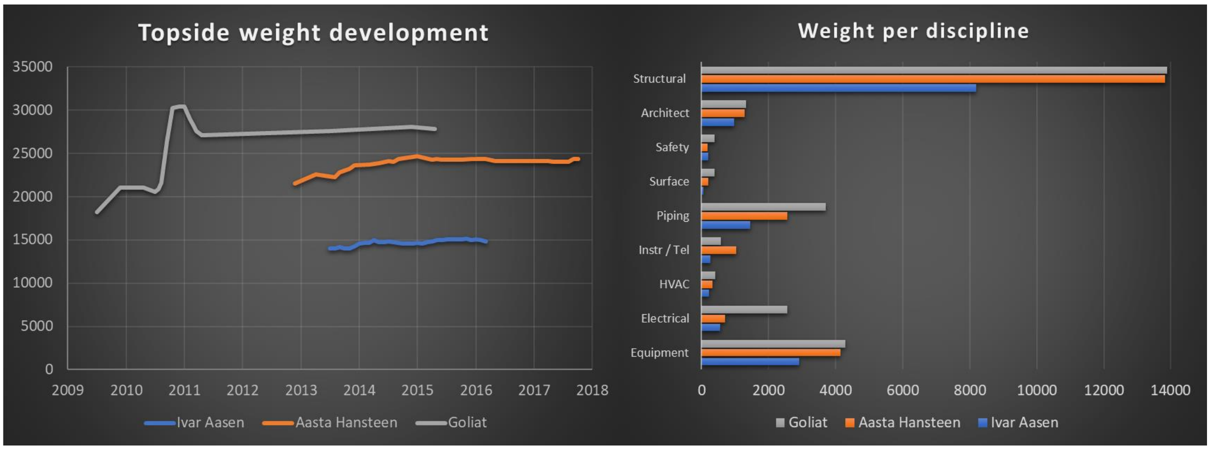


Figure 6-7. Weight development and composition for the three platforms. (Source: Acona)

Figure 6-8a presents discipline weights in relation to equipment weights, while Figure 6-8b shows discipline weights as a percentage of total topsides weight. “Reference” refers to the average of experience data from 16 different topsides.

The figure shows that the three platforms fit well in the general picture, but that some conditions need commenting on:

- Ivar Aasen lies closest to the norm
- Aasta Hansteen has a relatively high proportion of construction steel
- Goliat has an abnormally large proportion of piping and a very big share of electrical.

The reasons for these discrepancies are discussed in the chapters on the individual projects.

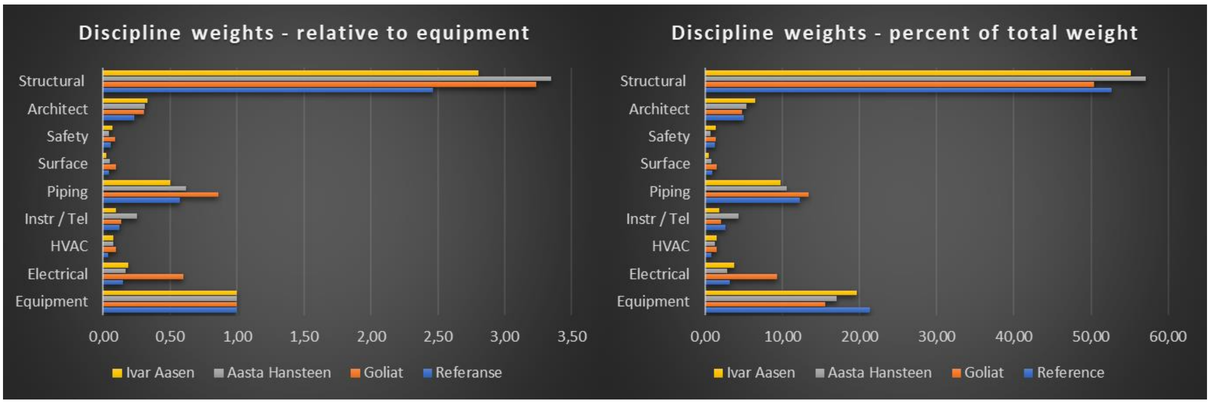


Figure 6-8. Analysis of weight composition. (Source: Acona)

Little attention was devoted to the weight estimate in the Goliat project until the PDO. Once the latter had been submitted in 2009, it was clear that weight was underestimated and had become a big problem by the autumn of 2010. A reliable weight estimate was not secured until the spring of 2011, and then remained stable for the rest of the construction period.

Where Ivar Aasen and Aasta Hansteen are concerned, detailed work on weight estimating had been done as early as DG2. Only minor weight increases occurred in the Feed and construction phases.

6.1.6 Basis for cost estimating

Several project reviews prompted by cost overruns and lack of project control were conducted over the years. The main points from three such reviews launched by the MPE are reproduced in appendix A.

Figure 6-9 presents the most important elements/activities which build up to cost estimates and plans. It is particularly important to note how the elements hang together and interact with each other. Explanations of why certain projects experienced big cost overruns and delays refer as a rule to one or more of the points listed on the left in the figure.

The Goliat, Aasta Hansteen and Ivar Aasen projects had particular challenges related to:

- new solutions/concepts (Goliat, Aasta Hansteen)
- understanding of regulations and standards (Goliat)
- contract forms/strategy (Goliat, Aasta Hansteen, Ivar Aasen)
- technical basis and weight (Goliat)
- experience data (Goliat, Aasta Hansteen)
- uncertainties in the market (Goliat, Aasta Hansteen, Ivar Aasen)
- high level of activity (Goliat, Aasta Hansteen, Ivar Aasen).

Unlike the experience of a number of other projects, few problems arose which could be attributed to the design base.

Uncertainty and problems in the areas mentioned above have had varying effects on the various sub-projects (platform, subsea installations and drilling). This meant Aasta Hansteen and Ivar Aasen came out well overall, despite challenges at the sub-project level.

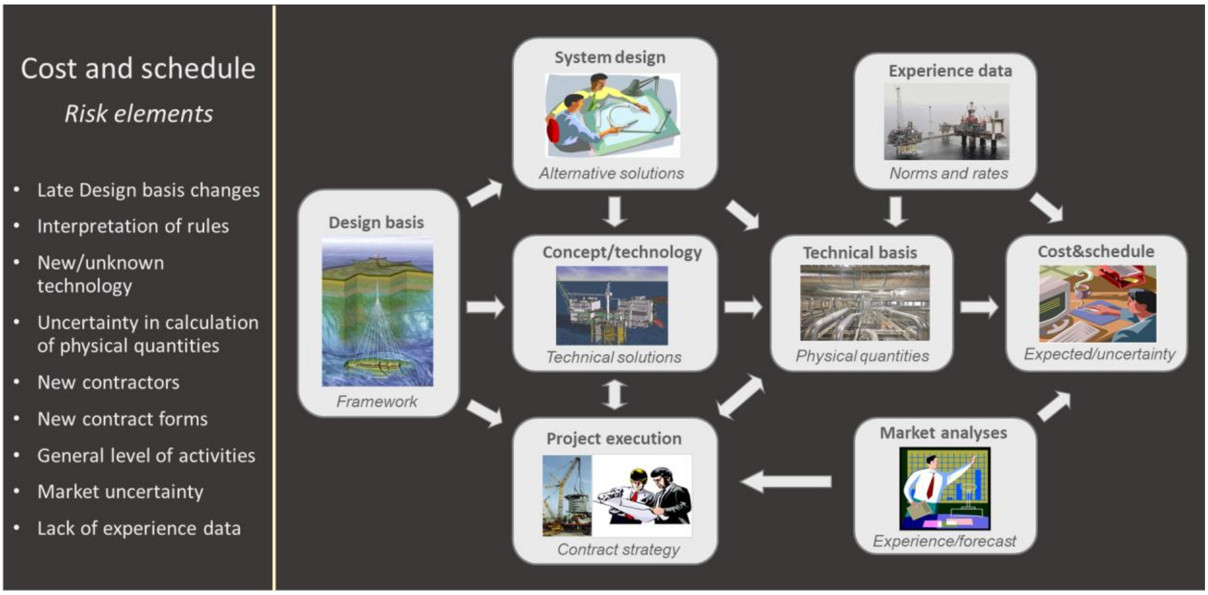


Figure 6-9. Basis for cost and plan estimates. (Source: Acona)

6.1.7 Decision assumptions

Planning and preparation of a decision base for the three projects occurred in 2007-13. Figure 6-10 shows how market prices and planning assumptions for oil varied during that period. The timeline for each project is shown in three phases – planning, development and production. The breakeven price for each project is plotted in at the PDO approval date. The figure shows that preparing the decision base for Goliat coincided with the financial crisis and a dramatic fall in oil prices. The PDO was approved right after prices bottomed out.

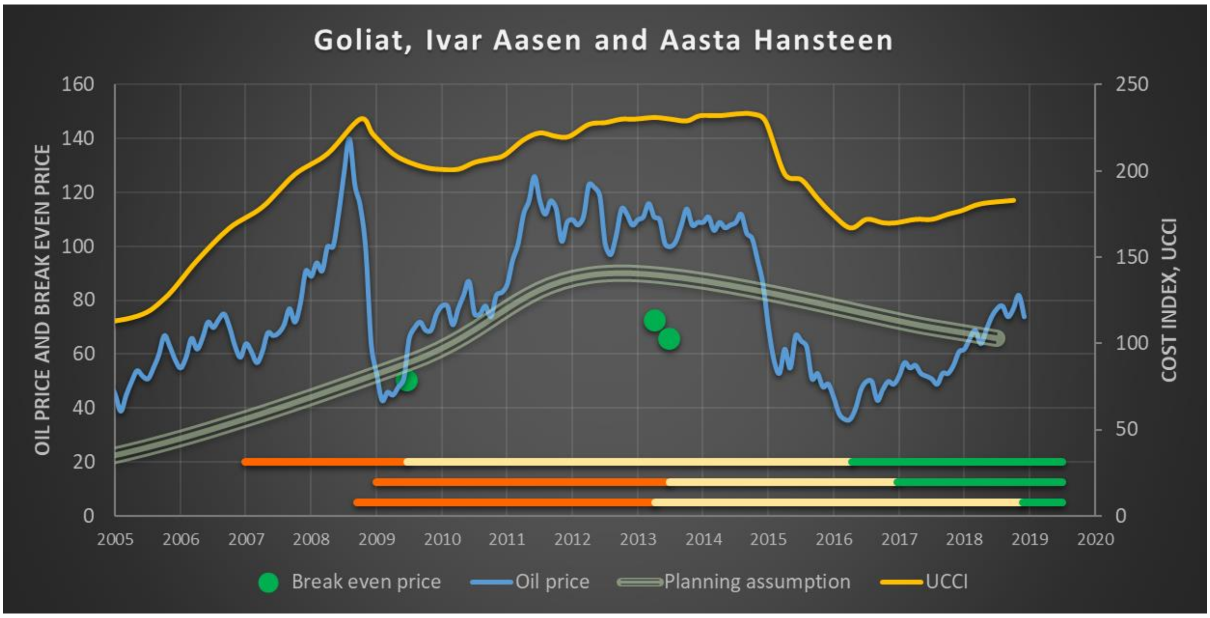


Figure 6-10. Variations in planning assumptions over time. (Source: Acona)

With Ivar Aasen and Aasta Hansteen, the PDO was prepared at a time of relatively high and stable oil prices. All the projects had a high breakeven price when the decision was taken. This price was higher for Ivar Aasen and Aasta Hansteen than for Goliat, but actual and expected oil prices made it particularly important for the Goliat project to keep costs down.

The decision base for Goliat was prepared in the second half of 2008, with the PDO submitted on 28 February 2009. This was at a time with an international financial crisis and oil prices in free fall – from USD 145/bbl to USD 35/bbl.

Although concern was growing among decision makers about the project's robustness to low oil prices, a general desire prevailed to persist with it and submit the PDO. A clear awareness existed in the project that the quality of the decision input (Feed) was weak, but a desire nevertheless prevailed to use no more time before submitting the PDO. The goal was to have the application approved in the summer of 2009. That reflected the political position. A general election was due that autumn, and it was feared that a possible change of government could lead to future delays. Opposition to oil operations in the Barents Sea existed among both politicians and non-governmental organisations.

In other words, the decision on execution was taken at a time when great uncertainty prevailed about the economic outlook, combined with a desire for a rapid clarification and pressure to keep costs down.

6.2 Project execution

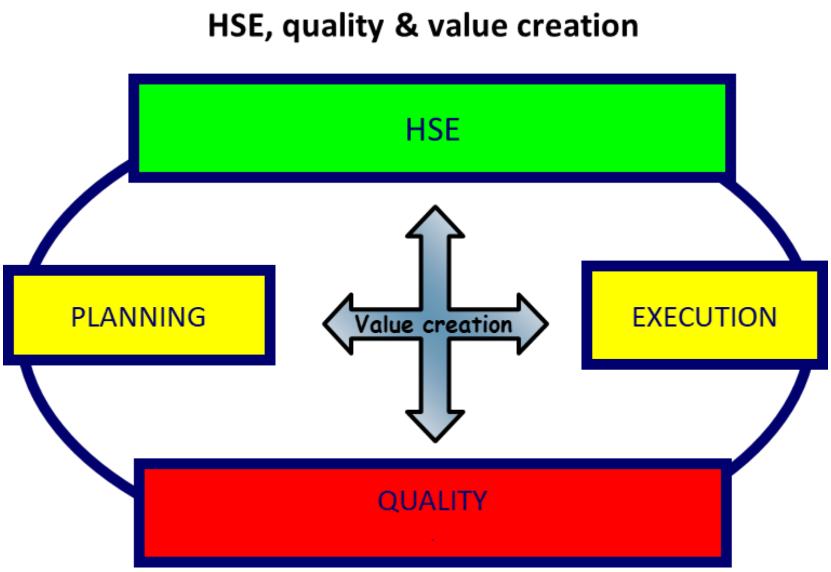


Figure 6-11. HSE, quality and value creation. (Source: Acona)

6.2.1 Expertise and organisation

The three operators had three completely different starting points when launching the relevant projects.

Equinor is the largest development operator on the NCS, with many projects both large and small under way at any given time. It has a big and well-functioning development organisation which works systematically on learning and continuous improvement. Furthermore, it has a well-functioning and solidly established quality assurance system with clear requirements on what must be in place at various DGs.

Eni had been present on the NCS since the early 1970s, but had never previously pursued a development there. Internationally, it had long experience as an operator, particularly in Africa. In other words, its Norwegian organisation had a limited operational background but stepped up recruitment from other sources once the Goliat discovery was made. The project was organised in a normal way before DG2. Dialogue with base discipline units in Italy appears to have functioned well and Equinor provided active support by making personnel available to the project and by having its own parallel project group. When the problems with a lack of maturation escalated in 2008-09, the project was reorganised and conflicts arose between it and the Norwegian base organisation and between Norway and Italy.

Det Norske's development experience was confined to a mini tie-in project in Norway. Its base organisation was limited in size. The development assignment on Ivar Aasen represented the company's big opportunity to build expertise as an operator oil company. That created great enthusiasm in the organisation and attracted able and experience project executors from other companies. A core of key personnel was established early, and these remained until the field had come on stream. The base organisation also regarded Ivar Aasen as its most important assignment and support for/assistance to the project had the highest priority at every level in the company.

6.2.2 Concept selection process

A standardised work process has emerged in the industry for choosing a development concept. This process is to some extent formalised and takes place between DG1 and DG2. After DG1 has been passed, the existence of at least one solution which is both technically feasible and financially acceptable must be documented.

A broad range of possible solutions are initially identified. These are assessed at a fairly rough level and ranked. A limited number of priority concepts are then selected for more detailed study. However, it is important that the documentation for excluding solutions is sufficiently detailed that no need or demand for re-evaluation arises at a later date. See Figure 6-12.

In the next phase of the concept selection process, work concentrates on a limited number of prioritised concepts which are further developed towards a final choice of concept. After this has been approved, a further maturation/consolidation takes place up to DG2. See Figure 6-12.

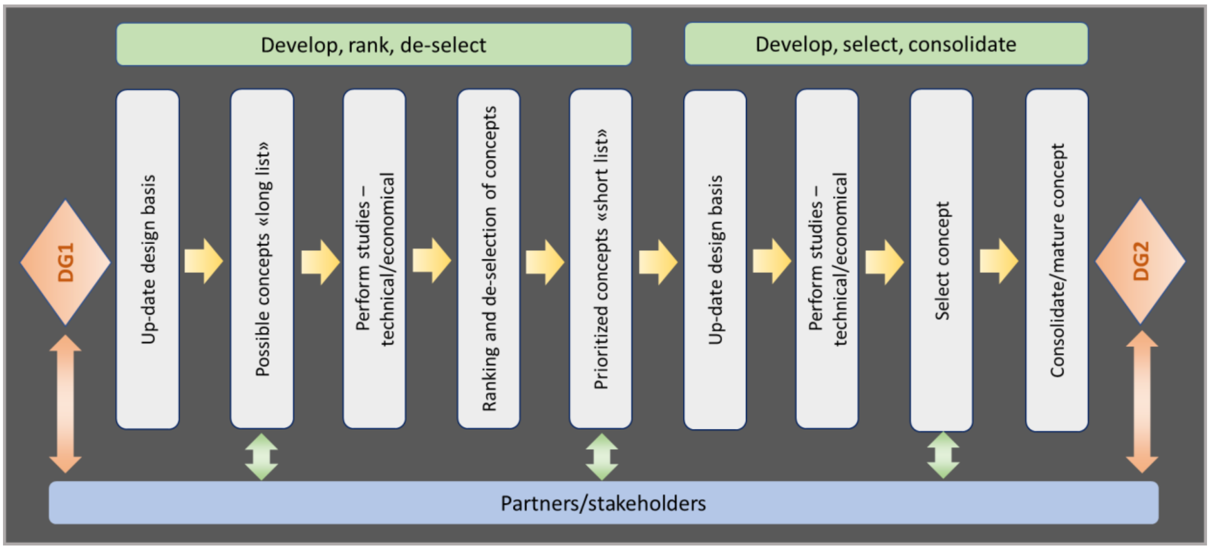


Figure 6-12. Overview of the various stages in the concept selection process. (Source: Acona)

Ranking, prioritisation and ultimate choice of concept are normally based on the present value of the free real cash flow after tax. Relevant risk factors are described, evaluated and included in the decision documents. Emphasis is also given to special profitability indicators such as the internal rate of return and to robustness against low oil prices expressed by the breakeven price. See also chapter 2.3.

In principle, the concept selection process can be implemented as a steady progression from DG1 to DG2. This assumes that all relevant concepts are included from the start, and that all stakeholders agree at critical stages – establishing a long list and a short list, and choice of concept. If these principles are not observed, delays can easily arise because new concepts are introduced or a "replay" is staged for concepts previously dropped.

To ensure work after DG2 is optimal, it is important that the choice of concept is as clear and precise as possible. Three factors in particular could make this difficult:

a. the concept is based on new technology which must be qualified
b. the concept is based on known technology but has not been realised before
c. the concept, or a significant part of it, is owned by the designer/supplier.

Of the three projects assessed, Aasta Hansteen had elements of new technology. However, technology qualification was done in a good way so that it did not cause problems with project execution. See chapter 6.1.2.

Both Goliat and Aasta Hansteen were based on solutions known internationally, but which had never been built for the NCS. In both cases, the complexity of both design and construction were underestimated. See chapter 6.1.2.

These two developments both utilised solutions where parts of the concept were tied to the supplier – Sevan and Technip respectively. To avoid being bound to a particular supplier as early as DG2, it was decided to enter the Feed phase with two competing solutions. Such an approach is resource-intensive and helps to make the work less focused. That can have unfortunate consequences by reducing Feed quality. This was one of the most important reasons why control of the Goliat project was later lost.

Ivar Aasen was the project based to the greatest extent on known technology and qualified solutions. A challenge related to the choice of concept was that the drilling rig had to be secured at an early stage, before DG2. The concept selection process for Ivar Aasen was otherwise characterised by disagreement in the partnership and the government's desire for coordination between Ivar Aasen and Edvard Grieg, as is described in more detail in chapter 5.2. This provides a clear illustration of the importance of involving all stakeholders and securing their agreement on plans at critical milestones.

Although the three projects have faced challenges in different ways over the choice of concept, no grounds exist for saying that any of the choices were wrong.

Appendix C presents an assessment of the chosen Goliat concept compared with a more conventional solution.

6.2.3 Execution strategy

The project and contract execution strategy must be tailored to the project's complexity and the market's capabilities (which change over time). The project's execution strategy should be established early and must take account of the operator's expertise/capacity, the market's availability and the project's size and complexity. See the project model in Figure 6-13. Active efforts must be made to draw on experience from other projects.

Where Goliat was concerned, what got completely out of control was project execution for the platform topsides. Quality/technical maturation of the platform was inadequate at every DG. In addition came an EPC(I) contract strategy where a contractor unqualified for this type of contract was chosen and the project team which never succeeded in securing control over the execution of the work covered in the contract.

Equinor entered into an EPC contract for the Aasta Hansteen project with HHI three years after Goliat.

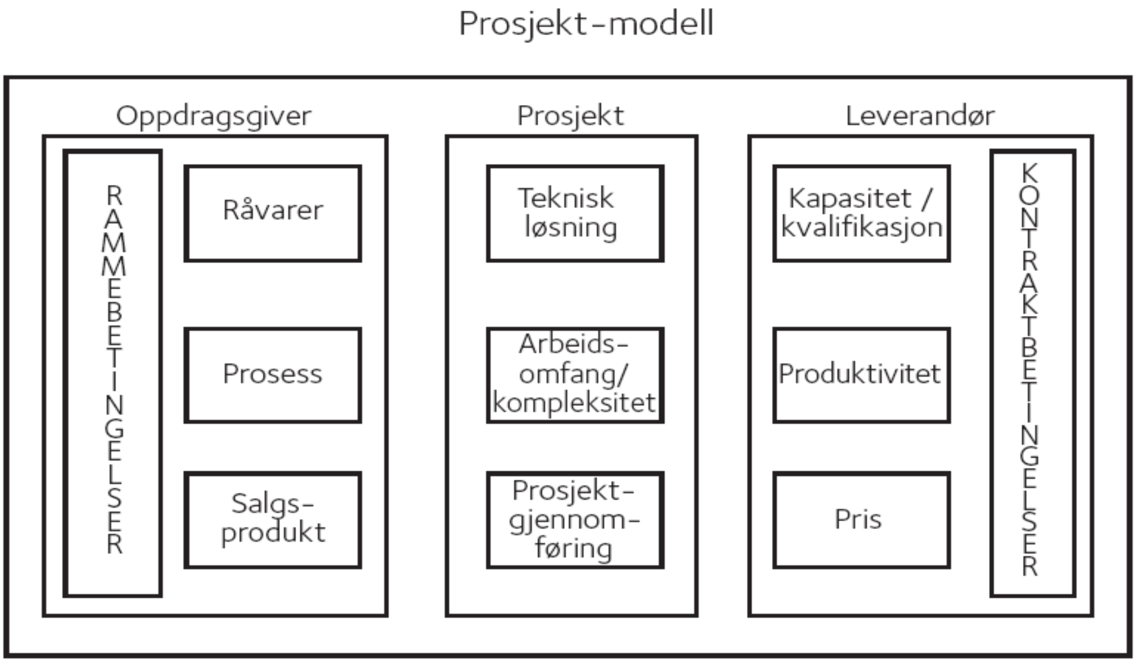


Figure 6-13. Execution strategy. (Source: Acona)

The latest experience from the projects shows that scope for improving execution strategy still exists. That covers such areas as organisation, expertise, attitudes and working methods. Important aspects are attitudes and conformity between word and deed – in other words, doing what one says and being open. Discipline is needed in relation to established rules, and the individual player/organisation must not least exercise good judgement.

Challenges which arise when using suppliers with a different culture, poor/no ability to plan/manage and a low level of completion have led to cost increases. The suppliers have underestimated the volume of work and had insufficient manning with poor productivity. This has led to substantial growth in in the scope of work. Little willingness to solve problems and poor collaboration between the various organisations have also had a negative impact on work results. The supplier generally offers delivery at a favourable price, but has inadequate management systems and poor productivity, resulting in delayed and/or incomplete deliveries.

EPC(I) contracts are being awarded today to suppliers who lack satisfactory execution capability in terms of spare capacity, adequate/competent personnel, management and so forth. In addition, EPC suppliers have had neither the desire nor the expertise to manage E(ngineering) or P(rocurement)

Execution strategy must be tailored to the actual market and the suppliers who are wanted must be carefully matched to the project's needs and challenges. The project's procurement strategy must be an integrated part of the overall execution strategy. These strategies must help to identify key risk factors in relation to market, supply and demand, and risk understanding.

6.2.4 Prequalification and selection of contractors

Prequalification and contract evaluation for key contractors must give far greater emphasis than is the case today to the contractor's capacity, yard facilities, execution, ability to plan and manage, risk understanding, level of expertise/competent personnel and experience/references. The prequalification process must be detailed enough to weed out possible suppliers with high execution risk and low delivery quality. Contract evaluation must take account of all actual costs related to transport, follow-up, productivity expectations and expected quality.

In the Goliat case, the contract was awarded a good year after PDO submission and the topsides scope of work/weight stabilised two and a half years after the PDO was submitted.

A concentration on costs has led to hasty decisions which initially appear to offer savings, but which turn out to lead to major negative consequences.

Prequalification, evaluation and normalisation of such deliveries with regard to planning and management systems appear to have been inadequate. Experience shows that suppliers fall short in complying with their contractual obligations. During prequalification and tender evaluation, more attention must be paid to capacity, personnel, yard facilities, the quality assurance system, HSE, management, planning and management, previous experience with the supplier and the latter's experience with similar work.

Furthermore, the correct use of expertise in prequalification evaluation is important, along with detailed investigations of Far Eastern suppliers in relation to expertise, capacity and ambitions. That requires paying the right attention, being hands-on, and not simply giving emphasis to the overall material (presentations, procedures and manuals) provided by the supplier but undertaking a detailed review of how the latter actually does the work.

References must be checked, details gone into or key supplier personnel talked with. In other words, the prequalification process must be specific, draw on experience from earlier projects, and acquire more experience/references from partners/partner projects. Detailed prequalification will ensure capable bidders and emphasise the experience of those potentially submitting bids.

The evaluation process must concentrate better on the supplier's ability to plan and to execute in relation to plans. Correct application of expertise, tender evaluation and detailed prequalification will ensure that only qualified bidders are assessed. Quality and delivery problems have been experienced with several of the contracts assessed in this review.

Great emphasis has been placed on price, even though the main risks/challenges have related to other factors such as time, quality and the need for technology development. Giving emphasis to and normalising the bidder with regard to planning and management are therefore important. Concentrate on the end result and ensure that adequate commercial value is placed on qualitative differences. Such variations between bidders are significant for the final contract cost. Suppliers are often chosen on the basis of price rather than other criteria, and negotiations over project management requirements are not tough enough.

6.2.5 Contract follow-up and project management

All experience shows that the quality of the work done in the early phase is crucial for the basis and thereby the quality of the execution phase. The soundness and accuracy of the project description, technical content and execution plans at DG2 are the key to securing a project with high value creation and good HSE results. An attempt has been made in Figure 6-14 to illustrate the relative influence at various phases.

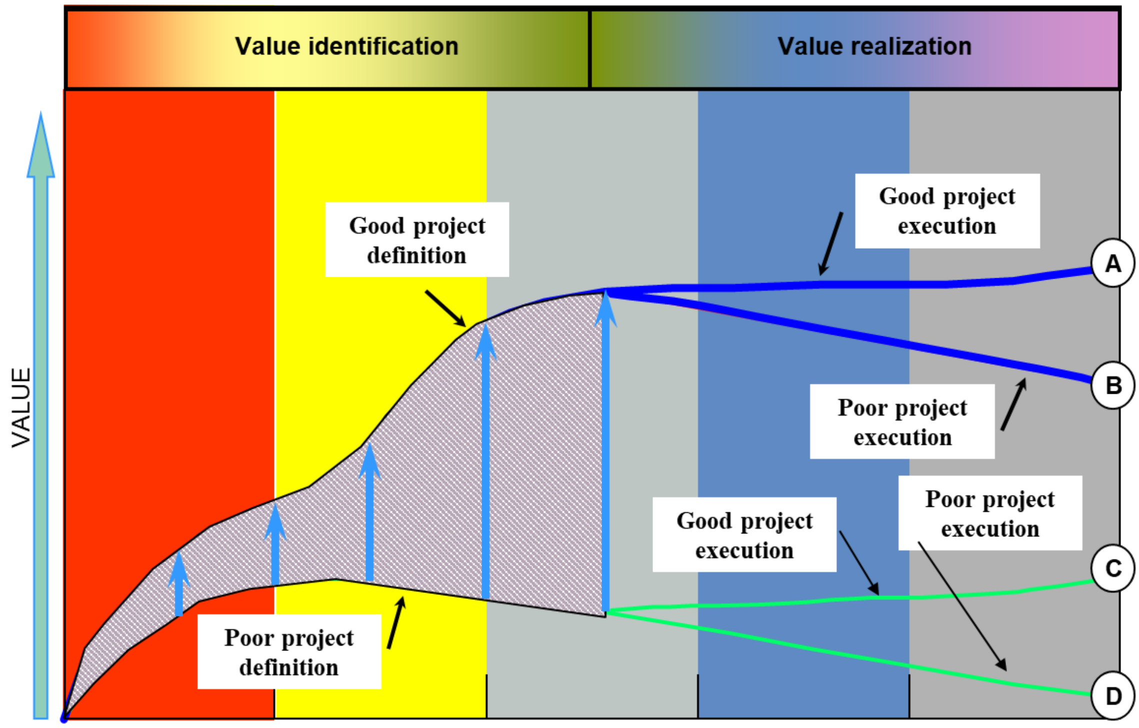


Figure 6-14. Contract follow-up and project management. (Source: Acona)

The follow-up team must have good expertise/be hands-on/pick up early/exercise good judgement and have measures for risk and project management and the contract's work content. Understanding the contractor's culture and attitudes is important, as is ensuring continuity in key positions (at the contractor and in the project team). Documentation must meet the right quality and accord with established rules. Executed/remaining work must be fully accurate at all times and must be communicated immediately.

At an early stage, projects must identify risk, establish preventive action plans and follow up at all levels. Good, realistic schedules with in-depth understanding of interactions across the project and between different contracts are crucial for success. Possible problems (time, cost and quality) identified must be tackled as soon as possible and reported immediately.

Control and management were lost in the Goliat project. It was insufficiently mature, with unrealistic plans and costs. The EPCI contractor failed to comply fully with the contract/ responsibility related to management/follow-up of subcontractors, progress reporting, costs/change orders, updated plans, quantification of the risk picture with measures and so forth.

As the contractor, HHI lacked E and P expertise, but nevertheless wanted to run things itself. Work was significantly behind schedule from the start. The technical basis was far from mature and the whole EPC(I) execution was mishandled.

HHI devoted minimal efforts to following up its EPC(I) responsibility, which ultimately forced Eni's project organisation to take over this role. Measures were put in place late and led to delayed deliveries with deficient quality, which in turn required substantial correction causing further delays in the construction process. The reported status corresponded poorly with the actual position,

Where Aasta Hansteen is concerned, the complexity/scope of work in building the hull was greatly under-assessed and underestimated. The Spar hull was on the critical path in time terms, and the construction period increased from 13 to 35 months. Nor was the project given priority by HHI initially, and thereby became very delayed. Equinor decided at an early stage to postpone the project by a year. As a result, more time was available to handle the topsides challenges which arose. HHI accordingly supplied one of the most cost-effective topsides (kilograms/tonne) delivered on the NCS since 2000. Equinor began managing the EPC contractor from day one.

It became clear early in the Ivar Aasen development phase that the technical basis had weaknesses, with a lack of Feed quality. SMOE also proved to be less than fully qualified as an EPC contractor. It did not follow-up procurement orders well, and the operator therefore in practice took this over itself. That produced good quality and on-time deliveries (some cost increase). The project team's ability to collaborate with SMOE meant no cost rise for the actual construction, although the number of hours increased greatly (doubling).

The latest experience from the projects shows that scope still exists for improving management/follow-up of deliveries. Discipline is required in relation to established rules and the individual player/organisation must not least exercise good judgement.

Where poor management occurs, the reasons can often be traced back to low maturity at DGs (unclear project assumptions, concepts not matured, technology qualification, and design basis not frozen). The consequences are delays and cost increases.

The Goliat project included substantial improvements and potential upsides in the early phase which later proved impossible to realise. In other words, it had an optimistic cost estimate and execution plan. The project was unable to implement the necessary measures, with cost overruns and substantial delays being experienced.

Outstanding items from the early phase were transferred to the execution phase with unclear project assumptions and concept/technology qualification which were not matured. The result was substantial cost increases and delays. In other words, the unclear project assumptions and outstanding items from the early phase led to optimistic expectations. Corrective measures were lacking and/or inadequate or too late. Uncertainty related to technology qualification was underrated.

Success with the decision base requires maturation in the early phase/securing a good base and giving quality priority in the first stage. Technology qualification projects need a detailed/better maturation, more planning and an increased commitment early. Contract follow-up and project management will ensure rapid/quick mobilisation of personnel and a realistic assessment of the supplier's scope of work. Detailed follow-up of the supplier's work planning is needed, plus managing change and uncertainties/risk at an early stage.

Emphasis must be given to clarifying interfaces between engineering, procurement, the construction site, subcontractors and completion. This includes managing and following up subcontractor activities, ensuring the right quality of documents and products, seeing to it that the EPCI contractor takes responsibility and the initiative, and determining a detailed construction strategy from day one.

The operator must intervene actively to ensure that the supplier manages the contract in an active way, and to get the necessary corrective measures taken to keep to the agreed plan. Open and precise communication is needed on status/trends/risk/corrective measures, and an active contribution must be made with regard to costs, plans and forecasts in the contracts. Giving emphasis to experience and follow-up strategy is important, along with active assistance to the supplier in areas where knowledge and experience are lacking. A stronger commitment must be made to active/detailed management of engineering, procurement and follow-up, and detailed/demanding requirements must be set for management/follow-up. Full insight into and understanding of the contract – in other words, rights and duties – are essential when following up at the construction site.

Success criteria for project personnel will be to succeed in the challenger role – not being "too nice". Build on genuine information from day one in the project. A conscious concentration on learning/experience transfer is needed. The contract is often overshadowed by local conditions at the supplier. Necessary measures must be adopted in time. Collaboration and professional customer/supplier relations are important.

6.2.6 Risk management

Best practice for risk management requires all projects to start the process by identifying and documenting possible uncertainties and risks from DG0. This means that attention must concentrate both on threats to and opportunities for value creation in the project. A systematic work process must therefore be established which involves all disciplines and all management teams in the project. Risks must be aggregated at different organisational levels, right up to the licence's MC, which will normally discuss the "top 10" risks.

All identified risks and opportunities must be analysed in detail, and action plans must be established with deadlines and responsibilities for all measures considered necessary to prevent/reduce problems or to increase the probability of gains. Discussions on the risk register with associated action plans must be a regular and integrated item on the agenda at all management meetings and every level in the project. Similarly, they must be on the agenda in follow-up meetings with all suppliers/contractors.

The risk register must be up-to-date at all times, and must cover all relevant conditions which could affect value creation, safety, the environment, the working environment and quality in the project. Examples of subjects which must be covered include the following.

- Uncertainty and risk related to understanding reservoir extent and content, as well as opportunities for efficient production and a high recovery factor.
- Challenges related to well location and safe execution of drilling, completion and production operations.
- Barrier philosophy with associated principles for management and control must be established early and be in place when the concept is chosen.
- The project must always have an overview of and control over all interfaces in the project, and have an overview of the consequences of changes made.
- The project's execution strategy, prequalification process and contractor evaluation.
- Realistic schedules (and cost estimates) with in-depth understanding of interactions across the project and between different contractors must be in place. Possible problems (time, cost and quality) identified must be tackled as quickly as possible.

All three projects had risk management in place early, but Goliat is the one with the largest number of deficiencies with late identification of actual risks (particularly related to execution and construction of the platform). It also had the least systematic follow-up by management at all levels. A systematic risk identification and reporting was established in the project, also covering the FPSO unit, and risks were identified and reviewed, but systematic impact analyses with subsequent action and prevention were inadequate.

6.2.7 HSE in the project execution phase

The three projects reviewed in this study have all had challenges related to HSE execution in a number of areas and at various times during the execution process.

Eni (Goliat) was aware that HHI was unable to point to relevant HSE expertise in engineering and procurement, but chose to rely on its subcontractor (CB&I London) providing the project with the necessary HSE expertise and thereby ensuring that the design would satisfy Norwegian requirements. However, the contract between HHI and CB&I was not framed in a way which ensured continuity in the collaboration between the two parties throughout the execution period. This resulted in the project being left without a "Norsok guarantor" before detail engineering and the procurement process got going properly. Eni's "vision" for EPC execution was to secure a turnkey product with a minimum of its own involvement. As a result, Eni decided to increase manning in project follow-up but pursued no formal active involvement in and strengthening of HHI's execution. Eni also became aware that HHI's technical follow-up of the procurement packages was deficient and thereby sought to allocate its own resources to secure satisfactory quality in the package deliveries. This measure also failed to have the desired effect, and the overall reason is again considered to be the lack of formal and genuine involvement in contract execution.

Moreover, Eni's fabrication and construction management at the yard did not work to an overall goal of delivering an installation to the end user (Goliat operations) which satisfied all requirements for HSE and operational safety. Instead, attention was concentrated unilaterally on ensuring that the platform had no deficiencies on delivery to the operations organisation. To achieve that, unfortunate methods were adopted which resulted in Goliat operations taking over a facility with an unknown number of undocumented deficiencies with varying degrees of seriousness – many with a potential to be safety-critical.

A few years after Eni chose HHI as its EPC contractor, Statoil made the same choice with both hull and topsides for Aasta Hansteen. As a partner in the Goliat licence, Statoil had good access to information about HHI as a contractor and could therefore tailor its management system to meet the challenges which it thought might arise. Subcontractors for engineering and procurement in both contracts followed the project to completion. Although the project did not make the expected progress, and the main contractor generally faced major HSE challenges at company level, Statoil succeeded in managing the project in a way which ensured satisfactory HSE results in both design and fabrication. Statoil's insight into and understanding of the way HHI executes its projects is considered to have been decisive here. This relates to HHI's extensive use of and relationship with subcontractors for fabrication disciplines and to the fact that the procurement process for a Norwegian offshore project requires a completely different regime for involvement from the buyer's side than HHI usually applies. Through its knowledge of these conditions and understanding of the challenges they represented for HSE execution in the Aasta Hansteen project, Statoil succeeded in implementing measures which secured satisfactory execution.

Feed for Ivar Aasen was executed by Aker Solutions London, and the topsides EPC contract went to SMOE with Wood Group Mustang London as engineering subcontractor. Det Norske regarded SMOE as a competent supplier since it had delivered the Ekofisk hotel topsides to ConocoPhillips Norge immediately before the award of the Ivar Aasen contract. An important consideration for Det Norske was that SMOE's moderate size meant the Ivar Aasen project would be significant for the yard. Moreover, Det Norske's project management could have direct access to yard and senior management at SMOE. The importance of being able to reach decision-makers while having the status of a main project was a direct lesson from the Goliat project, which was then struggling with major difficulties in making progress at HHI in South Korea.

Det Norske's assumptions about the contractor's Norsok expertise turned out to be wrong, but it managed to secure its own particularly competent personnel. The expertise of the team, and the "one team" spirit which was eventually established, short lines in the project organisation and a culture of identifying and dealing with challenges quickly became decisive for the project's success with HSE execution in design and construction.

Based on the findings from reviewing the three development projects, some conclusions can be drawn.

HSE aspects must be included in the concept evaluation from the word go. The most efficient execution is achieved if the HSE subject is integrated in all technical and commercial assessments. In order to rank various concepts and solutions, as well as variants of these, HSE goals and acceptance criteria must be defined for application as the level of detailing in the project increases. This is not special for HSE. Similar assessment criteria are used in project execution generally along the whole development path.

All the operators interviewed for this study have been able to identify to a greater or lesser extent how HSE is integrated in their project management, with the exception of one point. None of them could say with certainty that the company gives HSE aspects real significance in the prequalification process for possible contracts. Other, purely commercial considerations weigh more heavily.

If a big contract is awarded to a contractor who cannot point to satisfactory HSE results and management systems, this consideration should be reflected in the project's risk matrix so that compensatory measures can be implemented. Such action could be incorporated in the contract in the form of requirements for the contractor's use of competent personnel and for the commitment of key personnel to the project. Furthermore, the responsible contractor can be made subject to certain verification assignments, with follow-up and reporting. It is also important that the operator secures opportunities through the contract for its own presence in and management of the project. As with HSE management, a contractor's relationship to quality assurance will be crucial for the end result.

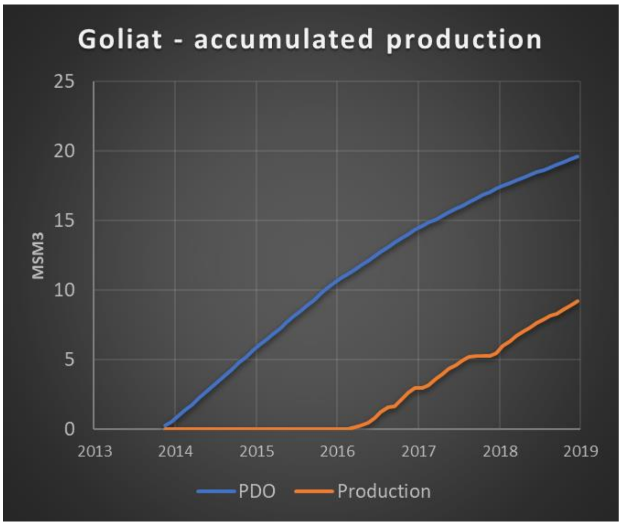
A common denominator for all three operators involved in this study is that they emphasise how resource-intensive the procurement processes proved to be. A lot of personnel and active involvement are required throughout the procurement path in order to ensure that package deliveries reach the necessary quality standard. Statoil, with all its experience, is the only operator which says that it was aware of this in advance, while Eni and Det Norske both express surprise at how time-consuming the follow-up of package suppliers proved to be as well as disappointment at the quality of deliveries. Both companies had advance expectations that Norwegian equipment suppliers would deliver better quality than proved to be the case. The conclusion from all three operators is that equipment deliveries demand substantial resources regardless of the nationality of the supplier company.

6.3 Production and operation

The date for coming on stream and production regularity are important factors for project economics and significant indicators of the quality of project execution.

A production profile presented in the PDO provides the basis for present-value calculations. Delayed start-up and lost production from shutdowns and reduced output mean postponed revenues and thereby weakened profitability.

Goliat was assumed to come on stream in the third quarter of 2013, but this was postponed until 12 March 2016 because of all the delays. Figure 6-15a shows accumulated production to the end of 2018 compared with the PDO assumption.



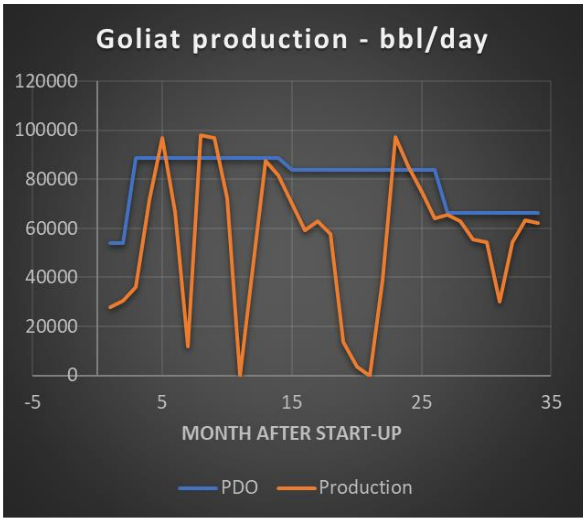


Figure 6-15. Production from Goliat. (Source: Acona)

Figure 6-15b presents daily production (monthly average) from coming on stream until the end of 2018 – about 34 months. As the figure shows, and as described in chapter 3.7, many and to some extent lengthy shutdowns have occurred. A lot of these have been HSE-related – HC alarms and leaks, power cuts, damage to loading hoses and so forth. Figure 6-16a presents the course of production day by day over the first eight months.

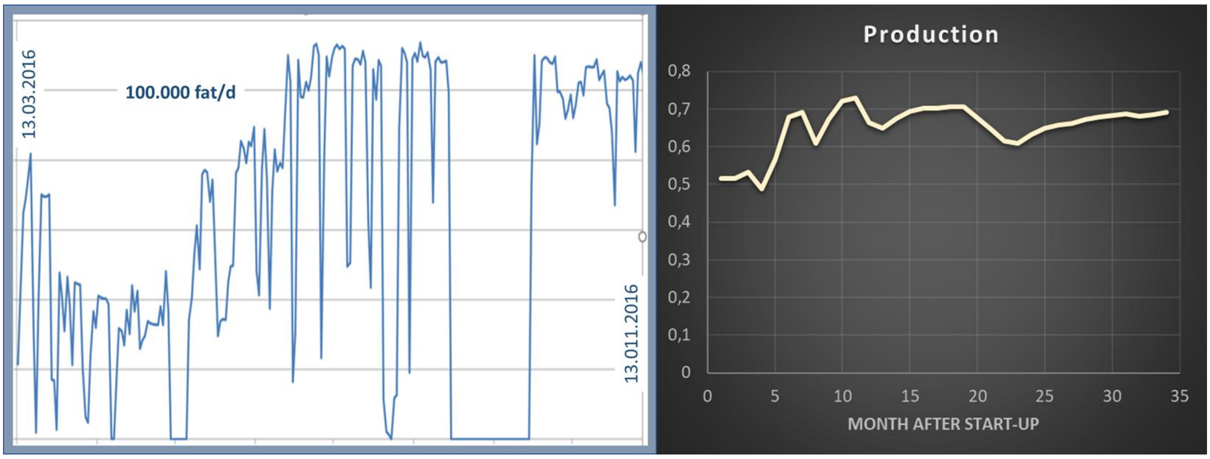


Figure 6-16. Daily and accumulated production in relation to the PDO profile. (Source: Acona)

Figure 6-16b presents accumulated production in relation to the PDO profile after a specified number of months. The shutdowns have caused big fluctuations, but the trend appears to have become better and more stable over the past 10 months. After 34 months, accumulated output is about 70 per cent of that given by the PDO profile over the period.

If production capacity is defined as the highest monthly average attained, capacity utilisation over the first 34 months can be said to have been 56 per cent.

Ivar Aasen was assumed to come on stream in the fourth quarter of 2016. It actually did so on 24 December 2016, only a couple of months behind the PDO assumption. Figure 6-17a presents accumulated production until 31 December 2018 compared with the PDO assumption. This shows that, although output began a couple of months late, it has been a little higher than expected on average. At 31 December 2019, accumulated production was almost identical with the PDO assumption.

Figure 6-17b presents daily output (monthly average) from coming on stream until 31 December 2018 – about 25 months. Production from Ivar Aasen is affected to some extent by its relationship with Edvard Grieg through production agreements and power supply. Accumulated output over the first 25 months was 109 per cent of the PDO profile over the same period – a very positive result which indicates good quality and a high level of safety.

If production capacity is defined as the highest monthly average attained, capacity utilisation over the first 25 months can be said to have been about 80 per cent. (Output from Ivar Aasen comprises oil, gas and NGL. The relationship between these sales products can vary over time.)

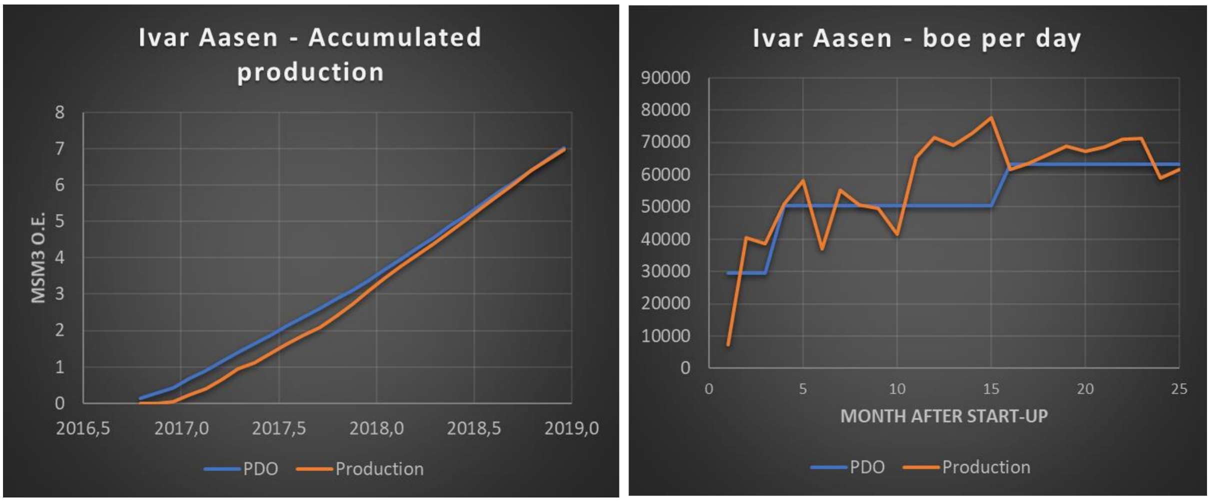


Figure 6-17. Production from Ivar Aasen. (Source: Acona)

Aasta Hansteen was assumed to come on stream in the third quarter of 2017, but did so on 16 December 2018 – more than a year behind the PDO date. Figure 6-18 shows accumulated output of export gas until 31 March 2019 compared with the PDO assumption.

Production from Aasta Hansteen comprises gas and condensate, and the relationship between these products will vary over time. Figure 6-18 presents daily gas exports (monthly average) for December 2018-March 2019 – about 3.5 months.

The accumulated volume of export gas in this period was 1.234 Gscm. Condensate output in the same period was 21 520 scm.

If production capacity is defined as the highest monthly average attained, capacity utilisation over the first 3.5 months can be said to have been 51 per cent.

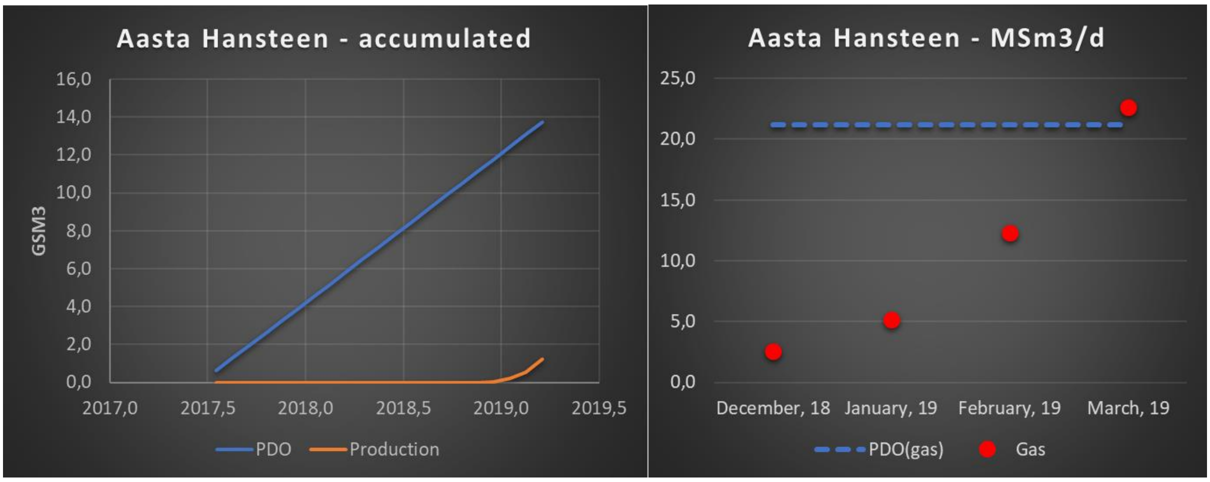


Figure 6-18. Production from Aasta Hansteen. (Source: Acona)

Goliat production has been weak compared with the PDO assumptions. To begin with, start-up was delayed by 28 months. Once on stream, output in the first 34 months was about 70 per cent of the PDO profile over the same period. Many of the shutdowns can be attributed to HSE-related incidents. This had big negative consequences for revenues, but the safety systems/barriers have functioned so that incidents never threatened to escalate.

Production from Ivar Aasen began only a couple of months behind the date assumed in the PDO. Output has been good, and the accumulated quantity after 25 months is virtually identical with the PDO assumptions. While the project's execution plan was tight and demanding, the final six months of preparations for coming on stream were characterised by good planning and control. The rapid production build-up, with good regularity, is an indication that the shortage of time did not undermine quality and safety.

Aasta Hansteen came on stream after a 15-month delay in relation to the PDO assumption. Following some running-in problems primarily attributable to cleaning and starting up wells, the field is now producing at full capacity. Gas exports in March 2019 averaged 22.6 Mscm/day, which means Aasta Hansteen reached full capacity just 2.5 months after start-up.

6.3.1 HSE in the production phase

The Goliat platform's many safety challenges in the production phase have attracted great attention in the Norwegian media. Much time has been devoted to following up the project and operator by the PSA, which has resorted to enforcement powers not commonly deployed against operator companies and licensees.

Eni's operations organisation faced major challenges on taking over the facility. This was primarily because an integrated operations team had not been adequately involved in the engineering, construction and completion phases, but also reflected the methods used by Eni's completion management in South Korea to conceal all types of deficiencies – including safety-critical ones.

This meant that the operations organisation took over a facility where it was not possible in practice to establish a complete overview of all the faults and deficiencies. Despite all the work devoted to corrective measures from arrival in Norway in 2015 until consent to come on stream was obtained in 2016, the platform still had substantial hidden shortcomings. The deficiencies eventually came to light from unexpected shutdowns. Over time, the field operators became more familiar with the design details and got the causes under control.

Goliat represents an important income source for Eni Norge (now Vår Energi), which the operations team is naturally aware of this at all times. In addition, the team experienced heavy and direct pressure from the company's central management to establish high and stable production from day one.

Goliat operations opted to try and balance its handling of the dilemma by staying on stream while correcting identified faults. However, this meant that the quantity of registered faults increased far more than the number of corrections performed.

The Goliat operations team has faced fairly substantial challenges in securing sufficient latitude to repair all faults and deficiencies. This has led the PSA to issue several orders to implement measures and to order a shutdown until the identified safety-critical faults had been corrected. Several orders have been unusual, including telling Eni to change priorities so that attention focused on safety and requesting Statoil's assessment of the condition of the electrical systems on the FPSO (Statoil is the only partner in the Goliat licence).

In interviews, Goliat operations has said that the PSA's orders had a legitimising effect in relation to resource allocation so that necessary repairs and other corrective measures could be implemented. That underlines the special challenge this organisation has had in getting support from the management of its own company. The last PSA order given to Goliat was in December 2018, based on an audit of Eni Norge earlier that autumn. From 10 December, Eni Norge and Point Resources merged to form Vår Energi AS. Nothing has so far emerged which suggests that the new operator will not manage to give safety the necessary priority.

The Aasta Hansteen platform had only been in operation for a short time when this study was completed. Equinor is the NCS operator with by far the greatest experience of running offshore facilities, and has therefore had no need to develop a dedicated management system for this field. It is utilising its established and well-proven solution for running offshore facilities, where managing HSE is an integrated component.

Equinor also has the advantage of a large organisation to recruit personnel from for all phases of a development. Where the operations team is concerned, this ensures access to relevant experience. That increases the organisation's robustness and can be important if special challenges arise. The platform faced some minor challenges in the start-up phase which affected production, but which have had no impact on HSE.

At the present moment, the Ivar Aasen development has a good two years of production behind it. The platform gets power from Edvard Grieg, and has experienced more or less planned suspension of these supplies. Losing main power has not affected safety on the platform, and Ivar Aasen generates sufficient electricity itself to keep comfort functions going until power deliveries resume. The decision to install a main generator of its own was taken after the PSA audited the design of the platform's electrical system, and the operations management has confirmed that this has had great positive significance.

Over these two years, modification projects have been implemented on the platform along with remote operation. This work has largely been conducted in parallel with regular operation without reports of any special HSE incidents or challenges. Nor has the merger of Det Norske and BP Norge to create Aker BP in 2016 had any significant negative effects on platform operation. After the merger, the company has rapidly implemented restructurings of its key management systems and procedures. Ivar Aasen's operations organisation has given priority to meeting its production goals and to implementing projects as planned while simultaneously maintaining satisfactory HSE management. The consequence of shielding platform operation from certain key changes is that not all governing documents and systems used on Ivar Aasen accord with Aker BP's centrally.

6.4 Supervision and follow-up

From the government's perspective, one of the main reasons for awarding production licences to a group of licensees rather than an individual company is to secure complementary expertise and to lay the basis for a system of checks and balances. The system of agreements has enshrined the official requirements set and the responsibility which rests on operator and partners.

The conditions for participating in a partnership are:

- all participants must be competent oil companies
- each participant is regarded as a separate legal entity with financial responsibility
- the voting rules are framed to give the participants the opportunity to exert influence on all important decisions, including the award of large contracts.

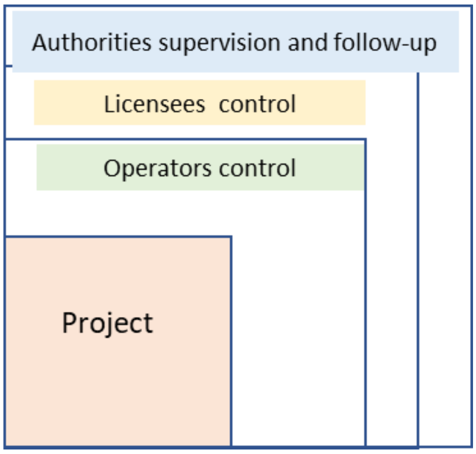


Figure 6-19. Outline of the control and supervisory hierarchy in a project. (Source: Acona)

To meet their obligations, the operator must have a management system which takes full care of self-regulation and the partners in the licence must implement a systematic structure for active follow-up and control of a project. The systematics in this can be compared with the barrier model implemented in the industry to take care of operational safety. By "barrier" is meant technical, operational and organisational elements which individually or collectively prevent undesirable incidents from developing further.

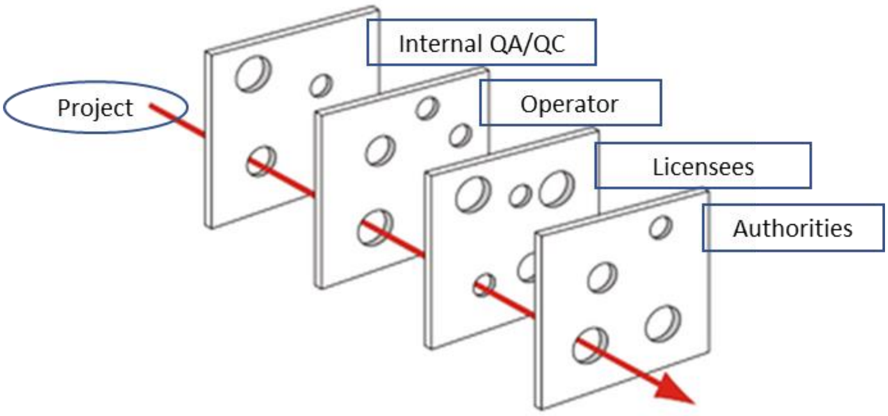


Figure 6-20. Barrier model for control of a development project. (Source: Acona)

6.4.1 Self-regulation in a project

The operator is responsible for all activities in a project and therefore for quality, HSE results, plans, budgets and production – in other words, all the elements which could affect value creation. It may allocate responsibility for the project in various ways in its own company, but experience from NCS projects indicates that it should have one – and only one – organisation (project or asset) internally to which complete responsibility is delegated.

Around this, a control system must be constructed where the operator exercises its self-regulation and facilitates independent control by the partners. Figure 6-21 presents an outline of the work flow between two DGs (DGn -> DGn+1).

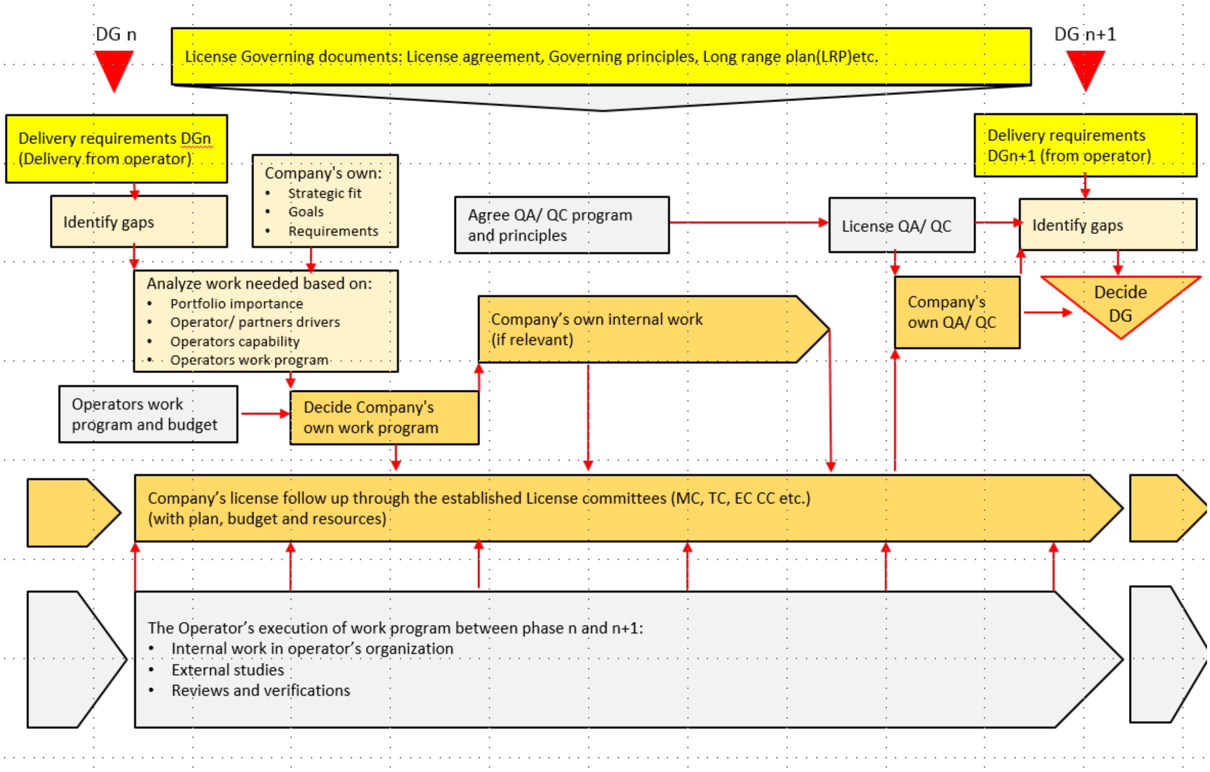


Figure 6-21. Operator and partner control of a project. (Source: Acona)

6.4.2 *Partnership's control of a project*

The Petroleum Act requires all licensees to have a Norwegian organisation able to take informed decisions on its own account. It is therefore important that all players have sufficient expertise in place in Norway to meet their obligations in relation to Norwegian legislation and regulations. The minimum requirements for partners are that they must, for all important decisions:

- be an independent external challenger to the project
- judge the quality and robustness of work done
- identify areas which call for more time and attention
- quality-assure planned schedules and cost estimates
- check that the project has done the necessary work to a sufficient level of quality to be able to continue
- assess the financial viability of the project.

Pursuant to the PDO guidelines (updated in 2017), the licensees must:

- act as an internal control system in the production licence
- see to it that the activities are conducted in a prudent manner pursuant to applicable legislation and that the operations ensure good resource management and HSE.

Practice relating to partner follow-up varies very considerably from licence to licence and partner to partner. The establishment of many smaller players in recent years has also meant that companies with limited experience of development and operation have become licensees in projects.

6.4.3 Government supervision of the activities

The government has no responsibility for either commercial results or the quality of project execution. On the other hand, it has a responsibility to supervise that the operator and the other licensees meet their obligations in relation to both regulations and applicable legislation. The government also determines which companies can be operators and which can be licensees in PLs.

In recent years, a number of new players have become established on the NCS. Some of these are limited in size and in their specialised expertise profile (an exploration company, for example). When such companies make discoveries and want to continue into a development phase, circumstances can arise which Figure 6-22 seeks to illustrate.

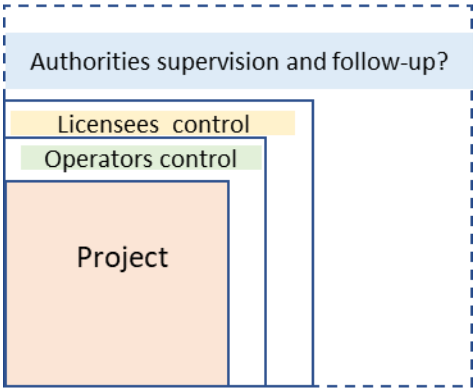


Figure 6-22. Control and supervision of newly established operators. (Source: Acona)

The project represents the bulk of the company's activities – in other words, its base organisation will have problems exercising independent internal control. If the other partners are also small and inexperienced, barrier control will be weakened. That may represent an increased risk for both project execution and HSE results.

In this study, the project team has found that the NPF and the PSA do a good job in relation to their main areas of responsibility (PDO consideration, resource utilisation and safe operation), but that it is apparent at the same time that their follow-up in the actual development phase is limited. Figure 6-23 seeks to illustrate this.

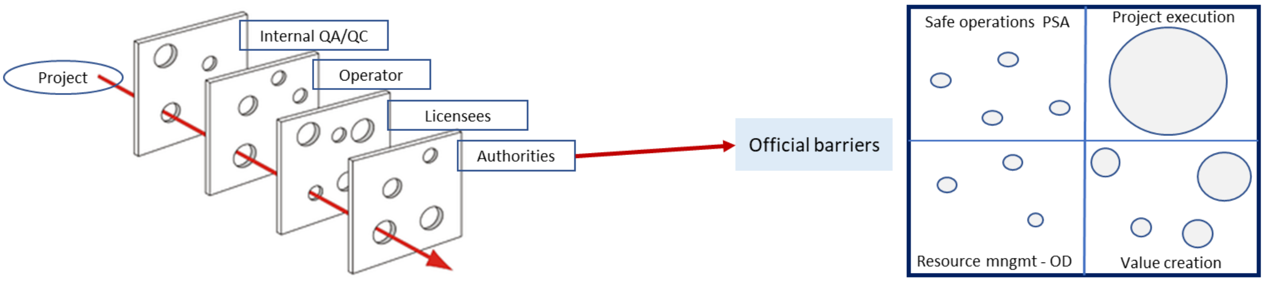


Figure 6-23. Barrier model. (Source: Acona)

The project team therefore takes the view that the government should either set stricter requirements for becoming an operator or a licensee in the development and production phases, or must strengthen its own expertise in order to be able to conduct more qualified reviews and supervision of development activities.

6.5 Development of plans, costs and economics over the life of projects

The figures below compare the three projects and present the development of costs for the overall projects and their main elements over time. They also provide an overview of project durations and measure these against the industry standard for similar developments.

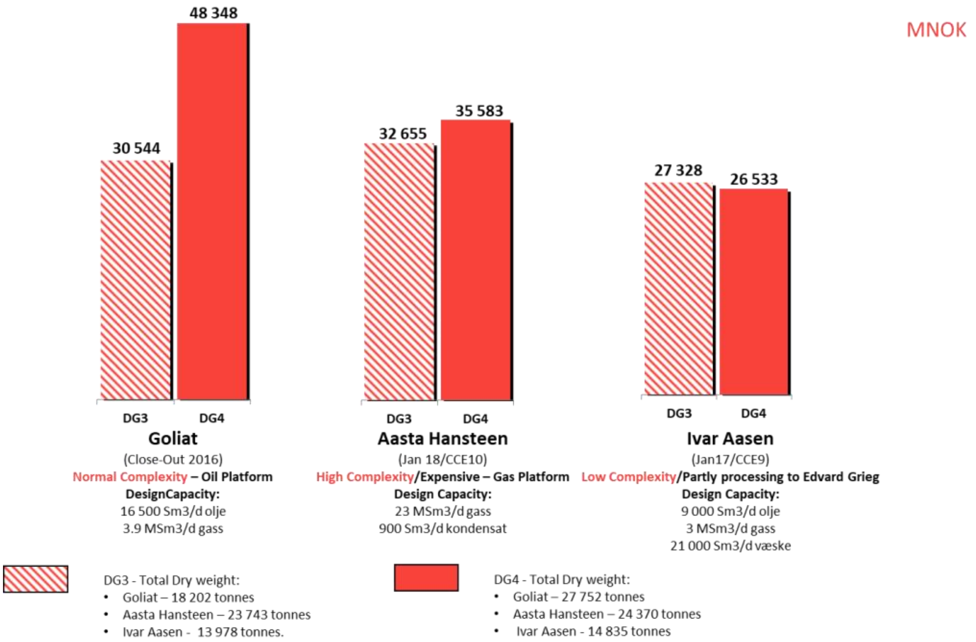


Figure 6-24. Capex – cost development. (Source: Acona)

	GOLIAT			AASTA HANSTEEN			IVAR AASEN		
MNOK	DG3	DG4	DIFF	DG3	DG4	DIFF	DG3	DG4	DIFF
Management	3 945	6 694		3 171	2 673		936	699	
FPSO	12 118	-		-	-		-	-	
Topside	-	14 523		9 881	13 298	+ 34%	6 065	9 025	**+ 49%**
Living Quarter	-	-		-	-		616	812	
Completion	-	2 566		-	-		1 113	2 566	+ 130%
Substructure	-	902		5 235	6 455	+ 23%	899	869	
Mooring,Offloading & Inst.	-	1 342		-	-		-	-	
Risers & Flowlines	2 406	2 987		-	-		-	-	
Heavy Lift and Transport.	-	-		-	-		571	423	
Extend./Remaining Scope	-	868		-	-		-	50	
Contingency	-	-		3 167	238		2 843	209	
Facilities – Platform	**18 469**	**29 882**	**+ 61%**	**21 454**	**22 664**	**+ 5%**	**13 043**	**14 653**	**+ 14%**
Facilities – Subsea & Pip.	2 818	2 996		6 062	6 086		1 363	1 240	
Drilling & Well	**8 186**	**10 479**		**4 431**	**2 821**		**7 774**	**5 545**	**- 29%**
Power Supply incl. Infra.	897	1 278		-	-		-	-	
Host	-			-	-		539	568	
PMT/Petek	-			201	321		279	297	
Preparation for Operation	174	207		-	291		850	934	
Insurance	-	553		507	400		259	197	
Adjust. (Currency impact)	-	2 953		-	3 000		-	-	
Phase 1	30 544	48 348		32 655	35 583		24 107	23 434	
Phase 2							3 221	3 099	
Total – Project Close-Out	**30 544**	**48 348**	**Close-Out16**	**32 655**	**35 583**	**Jan 18**	**27 328**	**26 533**	**Jan 17**
Total – RNB 2019	32 600	50 800	MNOK'16	34 600	37 500	MNOK'18	27 900	27 500	MNOK'17

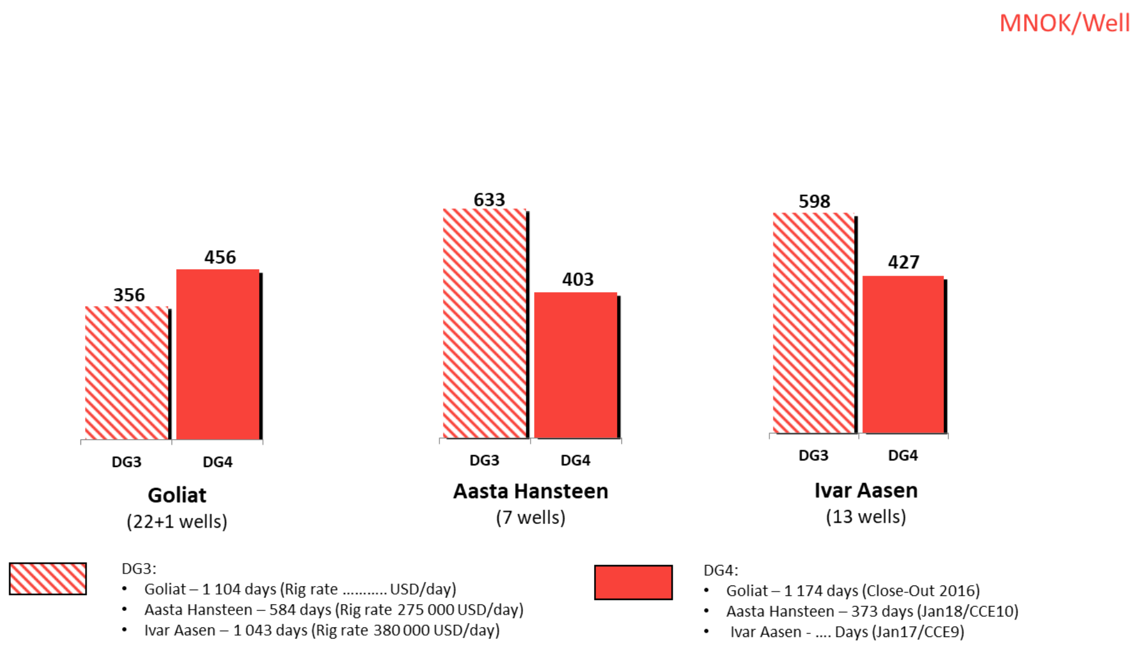
Figure 6-25. Capex – cost development. (Source: Acona)

Note: Goliat & Aasta Hansteen excl. Currency Impact.

Figure 6-26. Topsides – cost per kilogram. (Source: Acona)

Note: Goliat & Aasta Hansteen excl. Currency Impact.

Figure 6-27. Support structure – cost development. (Source: Acona)



Note: Goliat & Aasta Hansteen excl. Currency Impact.

Figure 6-28. Drilling and well – cost per well. (Source: Acona)

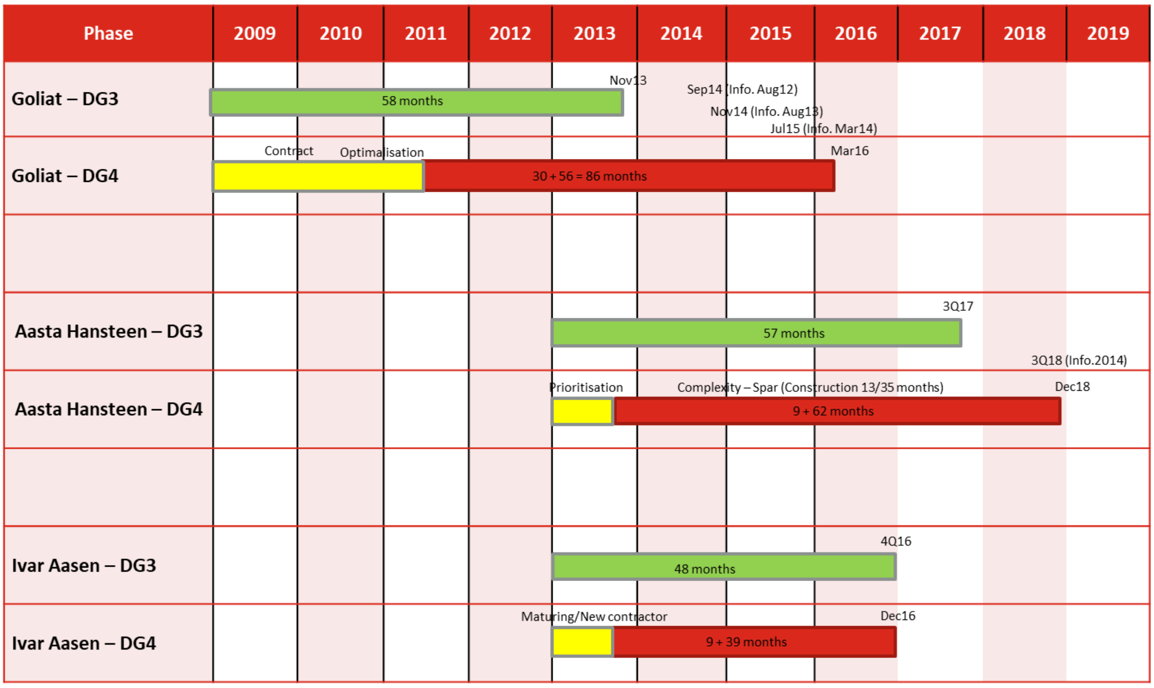


Figure 6-29. Execution – plan development. (Source: Acona)

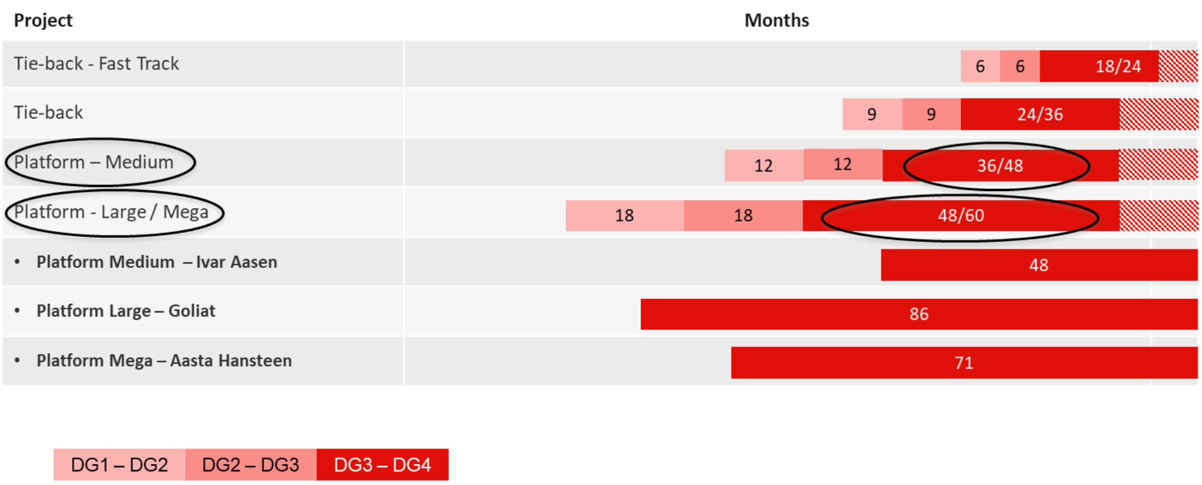


Figure 6-30. Execution – benchmark (experience). (Source: Acona)

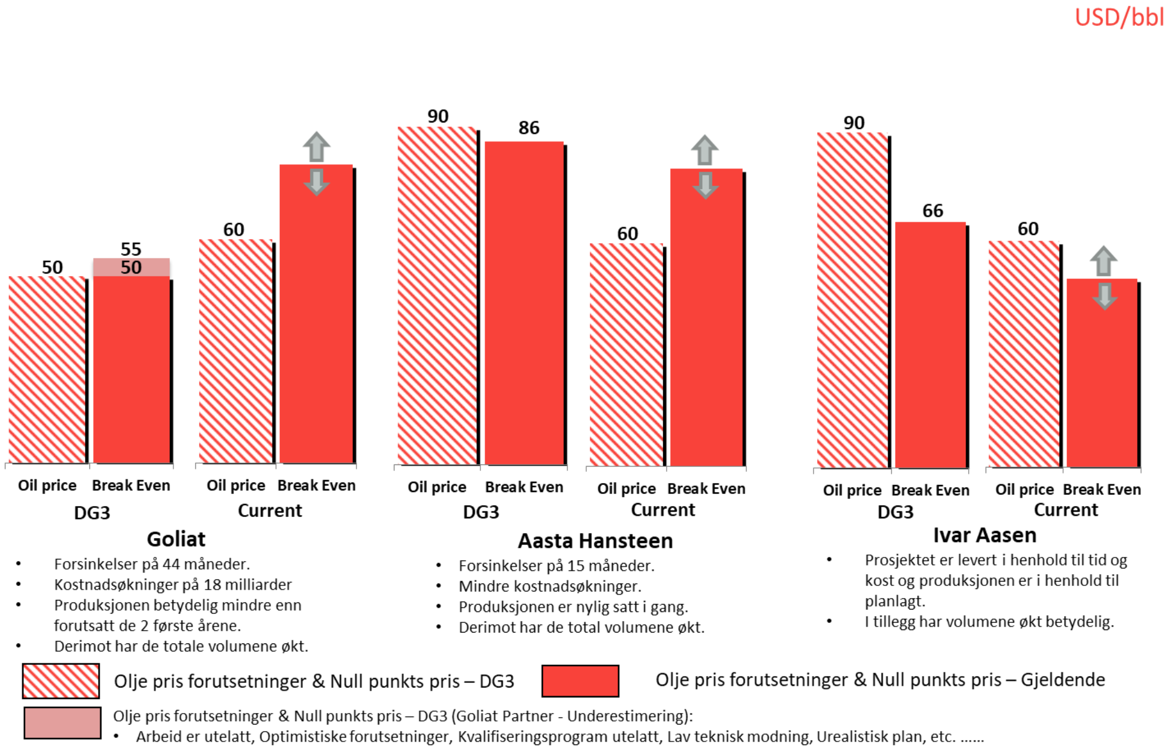


Figure 6-31. Oil prices and breakeven prices. (Source: Acona)

The common denominator for all three projects was a lack of maturity/quality when the main contracts for support structures and topsides were placed. The market was also tight and the suppliers lacked adequate capacity and expertise. An EPC strategy was chosen, which ended up with contractors who were not fully qualified for this form of contract and who were unable to exert control over the execution of the work included in the contracts.

Where Goliat was concerned, quality and technical maturity were inadequate/deficient and plans and costs for the platform were unrealistic at the DG. This meant that management of and control over topsides execution were lost. Uncertainty related to priorities and technical qualification of the Sevan concept for the platform was also underestimated. Contracts for the Goliat project were awarded a good year after PDO submission, and the scope of work/weight of the topsides were first stabilised two and half years after the PDO was submitted. Little commitment existed to overcome problems – in other words, collaboration between the various organisations was poor. That had a negative impact on the results.

The Aasta Hansteen project underestimated uncertainty related to a lack of priority at the yard and the complexity of the Spar hull through the introduction of storage. The Spar hull was not adequately detailed/matured before contract award. Priorities, capacity, technology development and other unclarified conditions in the execution phase increased the scope of work with associated cost rises and delays.

Uncertainty with Ivar Aasen related to the topsides supplier, who lacked the necessary expertise and capacity. It transpired that SMOE was not fully qualified as an EPC contractor and the operator took over follow-up/management itself. Good collaboration between operator and SMOE – in other words, a one team attitude – limited topsides cost increases.

Challenges from using suppliers with poor/little ability to plan and manage increased costs for all the projects. The suppliers underestimated the volume of work. Late/deficient prioritisation and low manning with poor productivity enhanced the expansion in the scope of work. The EPC(I) contractors failed fully to live up to the contractual conditions and the responsibility conferred by such a contract. That applies not least to management and follow-up of subcontractors, reporting of progress and costs, and qualification of the risk picture with measures.

When poor management occurs, its causes can often be traced back to an operator whose work in the early phase has been inadequate. The consequences of conditions such as low maturity at DGs, unclear project assumptions, an immature concept, technology qualification and a design basis which has not been frozen are delays and cost rises.

The EPC(I) contracts in these projects were awarded to suppliers who lacked satisfactory execution ability, sufficient spare capacity or enough competent personnel.

These EPC(I) suppliers also lacked sufficient expertise to manage E(ngineering) and P(rocurement). Prequalification and evaluation for key contracts must place much greater emphasis than at present on the contractor's capacity, the suitability of yard facilities, the execution plan, risk understanding, level of expertise and experience/references.

Requirements for success are adequate maturation in the early phase, provision of a good decision base and prioritisation of quality from day one. Technology qualification projects need more detailed maturation, greater planning and increased commitment early on. A stronger commitment must be made to active and detailed management of engineering, procurement and construction. Operators must take on the total overall EPC responsibility and, given the experience gained by the industry so far, contracts in the Far East must be limited to pure fabrication contracts (see Johan Sverdrup).

Although the Ivar Aasen project fell behind on maturation and the EPC contractor failed to accept its EPC responsibilities, it proved a success with regard to costs and time since the operator relatively quickly strengthened management through effective measures.

The Aasta Hansteen project also shows that good and active management by the operator meant the topsides were delivered by HHI as one of the most cost-effective structures of its type supplied on the NCS since 2000.

Documentation from the suppliers was incomplete and deficient. Actual status often fails to match that shown in the documentation. This poses a major risk for safe start-up and efficient operation.

Learning and experience transfer are crucial factors for achieving a successful project.

6.6 Industry perspective

6.6.1 Position of Norwegian industry

The oil supplier sector is Norway's second-largest industry (Menon, 2016) in terms of turnover, after the production and sale of oil and gas. It comprises in the order of 1 300 companies which deliver equipment and services to the petroleum sector. These companies had a turnover of NOK 340 billion in 2017, with 29 per cent coming from international markets. The sector has developed over 50 years of petroleum operations in Norway and ranks today as an innovative, highly competent and competitive industry both at home and abroad. Its five most important international markets by turnover in 2017 were the UK, Brazil, the USA, Angola and South Korea, with the last of these as the biggest.

Functioning as a technology lab has allowed the NCS to host the development of innovative solutions. Exploiting its resource potential has been an important precondition for research, expertise-building and the industry's ability to strengthen its competitiveness.

This functional approach was the purpose of the Norsok process. Through the latter, detailed specifications were to a great extent replaced by performance-based requirements. In the wake of this process, more technological innovations were experienced on the NCS, laying the basis for developing discoveries which had been considered non-commercial while improving recovery from producing fields. This technological progress also laid the basis for a growth in international turnover by the offshore supplier industry. In tough global competition, where most countries have a lower level of costs than Norway and technology can easily be copied, continuous innovation is essential for maintaining international competitiveness.

6.6.2 EPC as a contract strategy

Experience from various development projects shows that engineering expertise and capacity are critical, and that those who are good at drawing and planning are not also good at building. In a model with separate fabrication and engineering, the operator secures direct influence on the choice of all key suppliers. In the next phase, operators may choose to merge these activities in a new joint contact. Such a model can meet the operator's desire for more flexibility. However, it must assessed in relation to the market's capacity for contracts of this type. Limited capacity will also reduce choice. The challenge in recent years has been that many platforms for the NCS were constructed simultaneously, which therefore limited supplier capacity in the market.

EPC has been a much-used strategy in the shipping sector, which means that international fabrication yards are accustomed to this form of contract. However, the complexity of an offshore production facility far exceeds the level normally found in shipbuilding. Integrated EPC contracts are often described as turnkey assignments, where the operator companies expect fully complete products/components to be delivered.

Where offshore projects on the NCS are concerned, it remains the case that the operator has an overall responsibility for day-to-day management and project execution. From its perspective, awarding large EPC contracts for a specific development has both advantages and drawbacks. On the one hand, it reduces the operator's work in following up suppliers under such contracts. When an operator awards EPC contracts, responsibility for executing and delivering a turnkey assignment is transferred in principle to the supplier. However, few of the latter are willing to accept commitments of this kind, where they bear the whole financial risk.

It is important to emphasise that the operator bears ultimate responsibility in any event for HSE and that this will require detailed follow-up regardless of the contractual model. The normal procedure for such contracts is to operate with formal limits to the supplier's responsibilities, and the consequential cost of delays, for example, is not usually covered. That the development licence must pay the bill if the supplier cannot manage to bear the risk exposure in the contract is an important point.

Another drawback of EPC contracts from the operator's perspective is the time it can take to identify and execute necessary course changes when problems arise. Faults are often first noticed when the operator is some way into the project, and the process of reaching agreement on whether a deficiency exists – and correcting this – can be time-consuming.

A set of separate contracts, each with its own area of responsibility, is the counterpart to the EPC approach. Pursuing a strategy concentrated on this form of contract gives the operator opportunities to follow up the project in more detail by standing between the design/drawing supplier on the one hand and the fabrication contractors on the other. This means a contractual model with a high level of follow-up, control and handling of many interfaces between suppliers. It is reasonable to assume that big operator companies with resources can deal in a good way with a contractual model broken down into a number of separate contracts, while small and newly established players will have problems with such a model because of resource constraints.

The crucial factor for Norwegian competitiveness appears to be available capacity in the market, since contract follow-up and capacity have proved to be the biggest cost drivers in earlier projects.

6.6.3 Europe (Norway) versus Asia

In the Norwegian debate, the differences between projects carried out in Asia and those executed in Norway have been highlighted as a key explanation for why some developments are good and others less so. No such conclusion can be drawn from the review of these three projects. It seems to be fully possible to achieve good-quality construction with good HSE results in both Norway and Asia.

But this assumes that the chosen contract strategy, level of follow-up and methodology are tailored to local conditions. Project teams must also have the right technical and cultural expertise.

However, what does appear to be a general problem is that evaluation teams used by the operators at contract award systematically underestimate the gross cost of building in Asia. This requires a review of and an improvement to both the prequalification process at and the evaluation methodology and criteria applied by the operators.

7 Proposals for possible improvements

Based on the review of the three selected projects, the study has drawn up the points below as a checklist for safe, good-quality project execution. Many players already have most of these in place through their own requirements and management systems.

The nonconformities observed at the various players almost always represent deviations from their own guidelines and requirements. That is to say “compliance” represents the biggest improvement potential for virtually all the players. This means that, when planning work in the next phase of the project, all available methods must be deployed in relation to good quality plans and carefully prepared risk analyses with associated mitigating measures, which ensures that all the challenges normally faced in the relevant phase are thought through, planned for and taken into account.

7.1 Overview of operator’s work process and methodology

- Have a fully detailed management system with clear requirements for maturity, quality assurance (internal and external), and continuous collaboration across all functions in the project both before and after the various DGs.
- Strengthen internal quality control and project follow-up in the operator companies.
- Define expertise requirements, with genuine checking for key posts. Ensure that own personnel occupy key positions (limit use of consultants).
- The project’s mandate, organisation and responsibility must be clarified as early as possible.
- Ensure genuine involvement of the safety organisation and future operating personnel at an early stage, based the Norwegian tripartite model for collaboration between unions, employers and government.
- Do not pass DG2 or DG3 if the project/concept does not meet the maturity requirements (both commercial and technical).
- Have good plans for and full control over all technology development on which the project depends.
- Strive for continuity in key project posts and use team-building actively to implement shared ambitions, goals and attitudes, not only throughout the project but also with the operator’s base organisation, licence partners and contractors (one team).
- The project’s execution strategy should be established early and must take account of the operator’s expertise/capacity, market availability, and project size and complexity. Acquire experience actively from other projects.
- The prequalification process must be thorough enough to weed out possible suppliers with high execution risk and low delivery quality.
- Contract evaluation must take account of all actual costs (transport, follow-up, productivity expectations and expected quality costs).
- The project must be assured that contractors train their own personnel on the desired HSE standard and quality standards (Norsok and so forth).
- Early identification of risk, establishing preventive action plans, genuine risk management and follow-up must be on management-meeting agendas at all levels.
- Good and realistic schedules with in-depth understanding of interactions across the project and between different contractors are crucial for success.
- Possible problems (time, cost and quality) identified must be got to grips with as quickly as possible and be reported to both own management and the partnership.
- Good purchases depend on knowing what is being purchased. Operators should make greater use of technical specialists in procurement processes. Such personnel are better able than people with other specialisations to help reduce the scope of overlapping and unsuitable requirements and to assess the risk/benefit of proposed solutions. Technical specialists should supplement financial and legal expertise, not replace it.
- An overview of and control over all interfaces in the project must be maintained at all times, along with an overview of the consequences of changes made along the way (for the relevant contract, but also for other contracts).

- The principles of the operating philosophy must be in place at DG2. Production preparations, and making provision for safe work processes and procedures, must begin as soon as possible in detailed dialogue with those shaping the technical solutions.
- Requirements on the level of documentation and the operations system to be used must be clarified early enough for inclusion in the terms for all important deliveries.
- The division of responsibilities between project and operations must be crystal clear from mechanical completion of the first system until all the systems are handed over to operations.
- Requirements for the level of completion at the handover of responsibility must be established and never deviated from if this poses a safety risk.
- The main rule in the production phase: shut down if doubts over safe operation arise.

7.2 Partners and the partnership's responsibility

Pursuant to the PDO guidelines (updated in 2017), the licensees must:

- act as an internal control system in the production licence
- see to it that activities are conducted in a prudent manner pursuant to applicable legislation and that they ensure good resource management and HSE.

The following possible improvement areas (compliance) are identified for licensees:

- see to it and ensure that the operator's management system is up to the mark
- clarify the project's mandate, organisation and responsibility as early as possible
- establish common plans in the licence for reviews, quality assurance approval in both planning and execution phases
- do not approve DG2 or DG3 if the project/concept fails to meet the maturity requirements (both commercial and technical)
- be active in sharing experience from other licences and own business
- contribute to and support the operator in areas with identified expertise gaps
- assess the quality of the commercial and technical solutions presented as well as the realism of plans and cost estimates, and avoid time management affecting quality
- use expert consultancy support to cover gaps in one's own expertise profile
- see to it that the operator meets all clarified HSE requirements and quality criteria
- ensure that operations do not start until all necessary safety systems are in place.

7.3 Government's role

The following possible improvement areas are identified for the key players.

NPD

In addition to ensuring optimal utilisation of Norway's oil and gas resources, the NPD, together with the MPE, must be involved in planning and development of projects. It must be a driver in seeing that prudent resource management, good value creation and optimal social-economic results are secured. The NPD's resource management responsibility appears to be very well taken care of.

The NPD conducted *Vurdering av gjennomførte prosjekter på norsk sokkel* (see page 162) for the MPE in 2013. Project execution received a larger place in the NPD's follow-up in the early phase following this report. It has started to put questions to the operator as early as DG2 on relevant issues such as the degree of engineering completion, qualification of suppliers, contract strategy and taking care of risk.

Since 2014-15, the NPD has also conducted meeting series annually with selected projects in the execution phase. This is additional to the annual project updates providing information for the government's Finance Bill. These meeting series have typically been directed at issues related to project execution, weight development, cost developments, risk and mitigating measures. The purpose is to secure an updated status for the projects and to inform the MPE of this. That focuses attention on project execution in the various companies and informs the NPD, so that its follow-up in the early phase can be improved.

An improvement potential nevertheless appears to exist in assessing the realism of the technical concepts with associated execution strategies, schedules and costs, and consequent realisation of developments. Possible improvement areas are:

- seeing to it that a partnership has adequate expertise when PLs are awarded and when development decisions are taken
- further strengthening follow-up in the execution phase with expertise aimed at securing correct reporting and giving early warning to the MPE on upcoming execution problems, delays and cost increases
- establishing an even closer and better collaboration arena with the PSA, which could strengthen overall regulatory follow-up and supervision.

PSA

The PSA sees to it that HSE requirements are satisfied with an acceptable level of risk from choice of concept, through project development and into the production phase. It also gives consent to the start-up/commencement of defined operations.

This regulator has good technical expertise, and takes a systematic and risk-based approach to which projects, disciplines and issues it wants to audit. Possible improvement areas are:

- seeing to it that a partnership has adequate expertise when PLs are awarded and when development decisions are taken
- strengthening expertise in analysing, following up and taking care of HSE issues in the actual development phase
- setting clearer requirements for operator action plans and deadlines when issuing orders and conducting investigations
- carrying out spot checks to ensure that agreed actions have been closed in time and in an adequate manner
- establishing an even closer and better collaboration arena with the NPD, which could strengthen overall regulatory follow-up and supervision.

7.4 Supplier industry in general

The responsibility of the supplier industry is to deliver the products and services ordered by the project at the specified quality, right time and agreed price. Possible improvement areas are:

- strengthen specialist training and HSE awareness in their own companies
- continuous improvement in working methods and safe work operations
- deliver the right quality through good work processes and adequate quality control
- be realistic in the tendering phase with regard to capacity and expertise offered
- meet schedules and agreed milestones
- raise and help to correct errors by the operator as early as possible.

In both interviews and other arenas, the study team has noted that the Norsok standards could be improved and further clarified. A perception among engineers and operators in the field is that both form and language in the most recent updates have been generalised and made more academic. A new review administered by the Norwegian Oil and Gas Association ought therefore to be considered. Its purpose should be to determine:

- can the scope be further reduced?
- can a simpler, clearer and more direct language be used in the documents
- can requirements and descriptions be harmonised and coordinated between different documents.

Appendix A – Earlier project reviews on the NCS

Several project reviews have been conducted over the years against the background of cost overruns and lack of project control. The main findings of three such reviews initiated by the MPE are presented below.

Cost analysis of the NCS 1980

The MPE appointed a commission in 1979 to study the main reasons for costs trends on the NCS. This was prompted by the fact that projects executed off Norway at the time had experienced cost overruns of 178 per cent. The key issues for the commission were:

- why did costs become higher than originally estimated?
- should the assignment in question have been done in a more rational way and with smaller use of resources?
- should other technical solutions and organisational/administrative arrangements have been chosen?

The commission assessed two groups of projects – those already completed (Ekofisk, Frigg I and II and Statfjord A) and those which were still under development (Murchison, Valhall, Statfjord B and Frigg III).

Causes of the cost overruns were groups by the extensive and detailed report as follows:

- underestimating
- unforeseen inflation
- new government demands
- increased operator requirements
- inadequate project execution.

Analysis of investment trends on the NCS 1999

A commission of inquiry was appointed by the MPE in 1998 to analyse capital spending trends on the NCS. The main issue for the investment commission was to identify the reasons why such spending had risen in relation to the original plans.

Meetings were held with 11 oil companies, four manufacturers, a shipping company, the NPD, the Norwegian Confederation of Trade Unions (LO) and three industry organisations. The 13 projects examined in more detail by the commission had a cost increase of about 27 per cent. Drilling and completion accounted for a third of the overall rise. However, it was noted that the 13 projects had experienced a substantial cost reduction and faster execution than developments approved before 1994. Where HSE was concerned, the commission could show that this aspect had been given at least the same emphasis in these projects as in earlier developments.

The investment commission highlighted the following explanatory factors.

Optimistic/unrealistic estimates. The bulk of the PDO estimates in the period were unrealistic for reasons which can be traced back to underlying conditions characterising the times. Decision processes were often influenced by exaggerated optimism because of positive trends, uniformly unrealistic ambitions for substantial further improvements and little understanding of the uncertainty created by flimsy project maturation and the introduction of new elements. Ambitious goals set for cost reductions provided the incentive for the renewal required to achieve significant improvements. But it had to be emphasised simultaneously that the very ambitious goals were a general precondition for the weaknesses which led to the cost overruns. A general feature of the projects studied in detail by the commission was a weak decision base when the development was initiated.

Technology. A technology transition occurred with projects in this period, particularly for production drilling and well completion and the shift to floating production facilities with subsea wells. Implementing new technology introduced substantial uncertainty factors which was not adequately recognised in budgeting and executing the projects. That applied particularly to drilling and floaters.

Level of activity. This was significant for part of the cost rise. It applied particularly to drilling, but also to engineering and construction as an indirect consequence of the fact that unplanned activities had been added at players whose capacity was already almost entirely committed.

Short execution time. Execution of the relevant projects was characterised by lack of time, which had been reduced both in the phase prior to project launch and in the actual project. However, a number of the elements which had led to improvements also contributed to the overruns.

Modes of collaboration. The cost overruns could also be related to the new modes of collaboration between operator and supplier. That applied first and foremost to contractual relations, with the shift from a set of standard contracts for engineering and fabrication to more individually formulated turnkey agreements.

Assessment of projects implemented on the NCS 2013

The NPD was commissioned by the MPE in 2013 to review field developments on the NCS to uncover why some of these were brought in at their estimated cost while others became much more expensive than expected. The review was basically supposed to cover all projects with an approved PDO in 2006-08, but was confined in the event to five of these with three operators and a great variety of development solutions.

The NPD identified deficiencies in the following areas during the execution of these projects:

- work in the early phase
- prequalification of contractors
- contract strategy
- project follow-up.

These are regarded as the main reasons for the time and cost overruns. A high level of activity during this period put pressure on the market for all the projects. That resulted in a scarcity of resources and expertise, and also increased prices for input factors. This in turn helped to reinforce the negative impact on progress and costs in the projects. However, the review also found examples of projects which were completed in accordance with their estimated schedules and costs even though they were executed in a far tighter market than had been anticipated in the PDO. Typical characteristics of these projects where that the above-mentioned conditions had largely been well handled.

International deliveries. In the NPD's view, there was no basis for concluding that any direct relationship existed between overruns in the projects reviewed and the geographical location of fabrication sites. However, understanding of the Norsok standards and Norwegian government requirements were a bigger challenge at foreign yards than with fabricators in Norway.

Decision base. The NPD's conclusions concerning the reasons for developments in the five projects largely coincide with the collated causes identified by the investment commission in 1999. On that occasion, as now, it was noted that the basis for the cost overruns was laid in the early stage of the projects.

Lack of qualification and follow-up. Failure to qualify and follow up suppliers and sub-suppliers had been identified by the investment commission as another important reason. This was also noted in the NPD's review.

Technology. During the period covered by the investment commission, the industry underwent a technology transition – particularly the shift to floating production solutions and subsea wells. No similar change was identified in the projects assessed by the NPD. New technology elements appeared to be handled well in these developments.

Level of activity. This was also considered to be high in the period studied by the investment commission. The conclusion was that indications suggested the level of activity was significant for the cost increase, but that the main reasons for the rise related to other fundamental aspects of project execution. That corresponds with the findings of the NPD's review, which was based on a new period of high activity.

Appendix B - Reporting to the MPE reproduced in connection with the government's Finance Bill

Goliat

2011: No increase

2012: The updated investment estimate for Goliat is up by NOK 6.2 billion from the PDO estimate in 2009. According to the operator, this primarily relates to a rise in market prices, longer delivery times for equipment packages and higher raw material costs owing to heavy pressure in the supplier market. That has mainly affected the cost framework for fabrication and installation of subsea equipment and pipelines, well drilling and completion, and various equipment packages. The production unit has also become more expensive because of technological challenges, more extensive engineering and a higher workload than expected, which have led to a delayed delivery date. The profitability of the project remains good.

2013: The updated investment estimate for Goliat has risen by NOK 588 million from 2012 to 2013. The increase from the PDO estimate in 2009 is about NOK 7.6 billion. According to the operator, this rise primarily reflects an increase in market prices, longer delivery times for equipment packages and higher raw material costs owing to heavy pressure in the supplier market. That has mainly affected the cost framework for fabrication and installation of subsea equipment and pipelines, well drilling and completion, and various equipment packages. The production unit has also become more expensive because of technological challenges, more extensive engineering and a higher workload than expected, which have led to a delayed delivery date. In connection with the approval of the PDO for the Goliat field, a condition was set that the operator had to submit a plan for gas sales from Goliat to the ministry no later than two years before the field comes on stream. The operator submitted a broad report on plans for gas sales two years before the planned start-up. New sub-surface data and reservoir simulations have yielded new assumptions, and the operator is continuing to work on the plans. The ministry is following up this work.

2014: The updated investment estimate for Goliat is up by NOK 15.4 billion from the PDO. The rise from the same reporting last year is NOK 7.4 billion. The main reasons for the cost increase are higher market prices, longer delivery times for equipment packages, higher raw material costs and currency effects. The project has also become more expensive because of technical challenges, more extensive planning and a greater volume of work than expected, with the result that the expected date for coming on stream in now during 2015.

2015: The investment estimate for Goliat is up by NOK 820 million from 2014 to 2015. The rise from the PDO estimate in 2009 is about NOK 16.6 billion. The increase in costs relates primarily to market prices, longer delivery times for equipment packages and higher raw material costs owing to heavy pressure in the supplier market. That has affected the cost parameters for fabrication and installation of subsea equipment and pipelines, drilling and completion of wells and various equipment packages. The production unit has become more expensive because of technological challenges, more extensive engineering, various design changes, acceleration costs and a higher workload than expected, which have led to a delayed delivery date for the unit from the supplier and a consequent postponement of starting production. The cost increase from the previous report is caused by a weaker NOK exchange rate compared with the rate anticipated in the PDO.

2016: The investment estimate for Goliat is up by NOK 18 170 million from the PDO. The rise from the same reporting last year is NOK 1.2 billion. The cost increase from the PDO relates mainly to higher market prices, longer delivery times for equipment packages and higher raw material costs owing to heavy pressure in the supplier market during the execution period. The production unit has become more expensive because of technological challenges, more extensive engineering, various design changes, acceleration costs and a higher workload than expected, which have led to a delayed delivery date for the unit from the supplier. During completion of the platform on the field, quality defects were also discovered which had to be corrected before production could begin. That has both delayed coming on stream and increased costs. A weaker NOK exchange rate compared with the rate anticipated in the PDO has also helped to increase costs since the previous reporting.

Aasta Hansteen

2013: *No changes have occurred in the investment estimate* for the Eldfisk II, Svalin, Aasta Hansteen, Polarled including Kristin gas export, Ivar Aasen, Gina Krog and Varg gas export projects compared with their PDOs.

2014: *No or minor changes have occurred in relation to the cost estimates at the PDO/PIO dates* for the Aasta Hansteen, Bøyla, Edvard Grieg oil pipeline, Eldfisk II, Flyndre, Gina Krog, Ivar Aasen, Oseberg Delta 2 and Utsira High gas pipeline projects.

2015: An *increase of about NOK 650 million in the investment estimate* since the PDO has been reported for the Aasta Hansteen project. The rise from the same reporting last year is NOK 560 million. This increase reflects an extended construction period in South Korea. After reporting cost changes for the project in June 2015, the operator has informed the ministry of further delays to building the platform. This means that *coming on stream could be postponed until 2018*. Work is under way to establish the financial consequences of this. The ministry will revert with updates on the project in the Proposition on the new balancing of the budget for 2015.

2016: An *increase of NOK 4 887 million in the investment estimate since the PDO* has been reported in the Hansteen project. About half the rise reflects a weaker NOK exchange rate compared with the rate anticipated in the PDO. Investment has also increased because of more engineering hours and higher costs for equipment packages and raw materials. Progress at the South Korean yard has also been unsatisfactory. The licensees reported in the summer of 2015 that the planned start to production was postponed to the *second half of 2018*. See Proposition no 24 (2015–2016) to the Storting *Changes to the budget for 2015 under the MPE*. Since December 2015, the operator has seen a clear improvement in progress at the yard, and the project is now making good headway. The investment estimate is virtually unchanged since the previous reporting last year.

2017: An *increase of NOK 4 044 million in the investment estimate since the PDO* has been reported in the Hansteen project. This estimate is down by NOK 1 019 million from the same reporting last year. Most of the rise since the PDO reflects a weaker NOK exchange rate compared with the rate anticipated in the PDO. Investment has also increased because of more engineering hours and higher costs for equipment packages and raw materials. Since December 2015, the operator has seen a clear improvement in progress at the yard, and the project is now making good headway. Reductions since last year's reporting primarily reflect better project execution through reduced costs for drilling and construction of the platform.

2018: An *increase of NOK 2 858 million in the investment estimate since the PDO* has been reported in the Hansteen project, representing a reduction of NOK 1 259 million since last year's reporting. Most of the rise since the PDO reflects a weaker NOK exchange rate compared with the rate anticipated in the PDO. *Since December 2015, the operator has seen a clear improvement in the project*, and the facility is now undergoing completion out on the field.

Ivar Aasen

No changes were ever reported for Ivar Aasen.

Appendix C - Assessment of the Sevan circular FPSO concept versus a ship-shaped FPSO

The Sevan platform is described as an FPSO unit. Most units with a similar combination of production, storage and offloading are ship-shaped and are also designated as production ships.

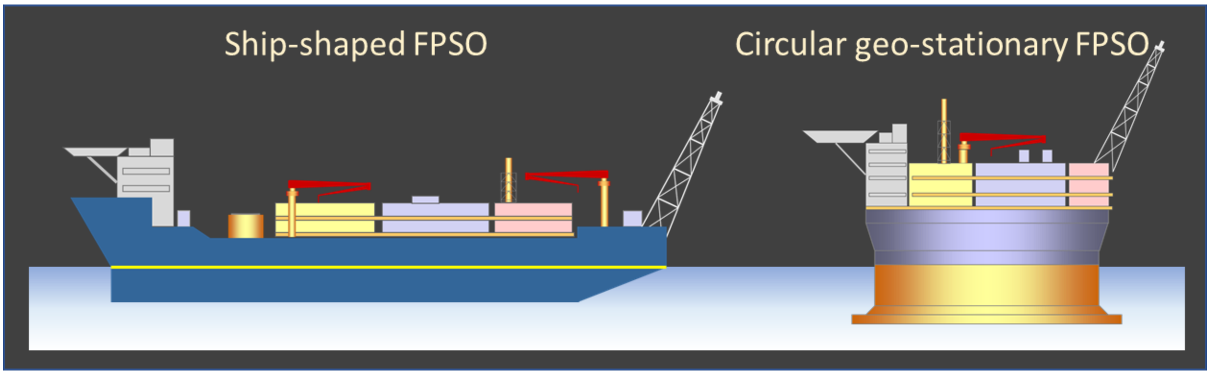


Figure 0-1. Comparison of ship-shaped and circular FPSOs. (Source: Acona)

The basis for the Sevan concept is a circular cylindrical structure with a relatively large diameter and small/moderate draught. Such platforms have been built for production, drilling and accommodation purposes, with the first becoming operational in 2007.

A large number of separate tanks accommodated in the hull can be used for ballast and oil storage as on a tanker, while equipment packages or modules can be arranged on the topsides for various purposes. The platform has substantial buoyancy and a big deck area.

The Goliat facility is the first and so far only Sevan platform utilised on the NCS. Sevan units with the same functionality are found outside Norway, but Goliat is the biggest in terms of both topsides facilities and storage volume.

Since nearly all FPSOs are based on a ship's hull, it is natural to compare the circular Seven platform with a ship-shaped facility featuring the same functions. Both advantages and drawbacks can be identified.

Mooring

A circular FPSO is moored with a fixed orientation in all weather conditions and is therefore "geostationary", unlike a ship-shaped FPSO which weathervanes around a central point and is always bows-on to the weather (wind and waves). This means that a circular unit can receive winds and waves from every direction, while the ship-shaped variant only gets them on the bows. Viewed in isolation, this is an advantage for the latter. But the ability to weathervane calls for some special, expensive, complex and function-restricting solutions. These involve a turret and swivel as well as propellers used to stabilise the heading in some circumstances. All mooring lines are attached to the turret, and all risers and umbilicals must be pulled in through it.

Risers and umbilicals

All risers and umbilicals are pulled up to the topsides on a circular FPSO via conductors running through the ballast tanks. A layout for a large number of risers and umbilicals is relatively easy to construct. As mentioned above, risers and umbilicals on a ship-shaped unit must pass through the turret, which can become a bottleneck with more limited capacity. In addition, all oil, gas and water pipelines, control functions and power cables must be conducted through a system of swivels installed atop the turret. This swivel arrangement can be complex, restrictive and vulnerable. In that way, the need to be able to pull in an electricity transmission cable became crucial for the choice of a circular FPSO on Goliat.

Hull strength

Both circular and ship-shaped FPSOs must be dimensioned against static and dynamic water pressure, including wave slamming. A ship's hull 250-300 metres long is also exposed to large global static and dynamic bending loads, which occupy a key place in dimensioning the structure. A circular hull does not face that challenge.

Motions and accelerations

Good seakeeping properties had a high priority in developing the Sevan concept, with a special "bilge keel" at the base of the hull helping to dampen motions. Experience so far is that the Goliat platform has good motion characteristics compared with other floaters. This is beneficial for the process plant and contributes to a good working environment on board.

Wave slamming and green seas over the deck

Waves slamming against the deck or possible green seas washing over it pose a challenge for all platforms, both fixed and floating. This is particularly important for floaters, which should preferably have a low centre of gravity. Calculating such phenomena is difficult, and must be supplemented with extensive model trials. A ship-shaped FPSO which lies bows-on to the weather is designed with a high forepart to shield the process facilities. Under certain circumstances, green seas may nevertheless wash over the tank deck. On a geostationary circular FPSO, the waves can come from all directions. Heavy and extensive structures are therefore needed to protect the main deck. Experience so far is that green seas over the deck do not appear to be a problem. However, it is too early to draw any conclusions. If they happen at all, such events will only occur in special, rare and extreme weather conditions.

Offshore loading

Offshore loading has always been regarded as a weather-dependent and relatively risky business. The equipment used, which includes large-diameter loading hoses, is exposed to dynamic loads and subject to wear and tear. A long hose is more vulnerable, but a short one reduces the distance between FPSO and tanker and thereby increases the collision risk.

As mentioned above, a ship-shaped FPSO lies bows-on to the weather. The wind thereby always blows from the FPSO to the shuttle tanker – an important safety characteristic. This is more demanding for a circular FPSO with a fixed orientation.

The Goliat FPSO was initially designed with two loading stations for use in different wind directions. At some point, however, it was decided to eliminate one of these for weight and cost reasons. A special system has been developed, with detailed operational procedures, for the way tankers should operate under changing wind conditions. Nothing suggests that these operations pose any problems, but the loading hose used is longer and more vulnerable than those on ship-shaped FPSOs. (Tankers must lie closer to a ship-shaped FPSO because the wind blows from the latter to the former.)

It has been proposed that the problems with the loading system could be avoided by using a loading buoy as on Statfjord and Gullfaks. But such systems also have their costs and technical challenges.

Layout and construction

The topsides layout is important for many reasons – safety, construction, materials handling, operation and maintenance. A common view is that the long and narrow layout typical for ship-shaped solutions is particularly favourable for both safety and construction. Over the years, a best practice has been developed for how this should be done. However, two very different solutions exist – the Norwegian model, with the quarters forward, and the "international" type based on conversion of tankers, with the quarters aft.

Where the circular solution (with large hull diameter) is concerned, making the best possible use of the circular topsides area is desirable. But no well-established practice exists which could be referenced. Ventilation across the topsides presents a challenge.

Construction represents another challenge. The topsides for the Gjøa, Goliat and Aasta Hansteen platforms are illustrated in Figure 0-2. Variations in reservoir fluids mean that great equipment differences exist between these three structures, but their total topsides weights are not so very different. The rectangular Gjøa topsides is a type known from a number of platforms and considerable experience has been acquired with them. The Aasta Hansteen topsides are designed like a conventional installation on a fixed platform.

Gjøa and Goliat have virtually the same deck area (footprint) and a “flat” layout, while Aasta Hansteen has a smaller deck area and greater height. The solution with a long and narrow topsides, like that on Aasta Hansteen, is regarded as favourable in terms of a good distance between hazardous and less hazardous areas, good divisions between the platforms main areas and good natural ventilation across the decks. Over time, well-thought-out solutions with physical barriers and escape routes have been developed for the type of topsides used on Gjøa. Goliat has some common features with Gjøa, but is nevertheless distinctive.

The topsides for Gjøa and Aasta Hansteen were built as a single unit and installed on the support structure with the aid of barges. In the Gjøa case, a barge which could be floated in between the hull columns was used. Where Aasta Hansteen was concerned, a barge was located at each end of the topsides.

Goliat’s topside, on the other hand, is wholly distinctive. The big hull diameter means that installation with the aid of barges is difficult/impossible. For the same reason, lifting large modules into the centre of the deck is difficult. A construction method was therefore chosen which involved lifting a large number of small sections on board and hooking them up. As detailed in the assessment of Goliat, most of the problems for this platform related to the topsides.

Figure 0-2. The Gjøa (left), Goliat and Aasta Hansteen platforms. (Source: Acona)

Although no good practice had been established for building platforms such as Goliat, little was done in the early phase to come up with an appropriate layout and construction method. Some improvement proposals have subsequently been made for a possible new project.

Working environment/weather protection/winterisation

A cold climate with the threat of snow and ice accumulations was regarded as a challenge for Goliat. Experience with the solutions chosen has been good. The winterisation walls provide good protection against cold winds at the same time as ventilation is satisfactory. No significant ice accumulations have been experienced.