Northern Lights Project Concept report

RE-PM673-00001

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1 Introduction

The Concept Study report ("DG2 report") was the primary deliverable at Milestone M5/M6A of the Study Agreement. The report was written in November 2018.

Due to the change from Smeaheia to Aurora as storage complex, subsurface studies were further matured up to milestone M6B in March 2019. This revision includes a summary of the subsurface studies up to milestone M6B but does not reflect other changes to concept development or schedule since November 2018.

1.1 Project owners

The pre-project (concept and FEED studies) is governed by a study agreement between Gassnova and Equinor. A collaboration agreement between Equinor, Shell and Total governs the study work and the preparations for establishing a JVA at the time of a positive investment decision by the partners.

2 Project Summary

2.1 Project description

The Northern Lights project is part of the Norwegian CCS demonstration project with capture of CO_2 from industrial sources in the Oslofjord region, shipping of liquid CO_2 from capture sites to an onshore terminal on the Norwegian west coast, and pipeline transport from onshore to an offshore storage complex in the North Sea. A full chain schematic is shown in Figure 2-1. The Northern Lights project includes ship transport, onshore storage, pipeline transport to an offshore injection well, and injection of CO_2 for storage in a subsurface storage complex.

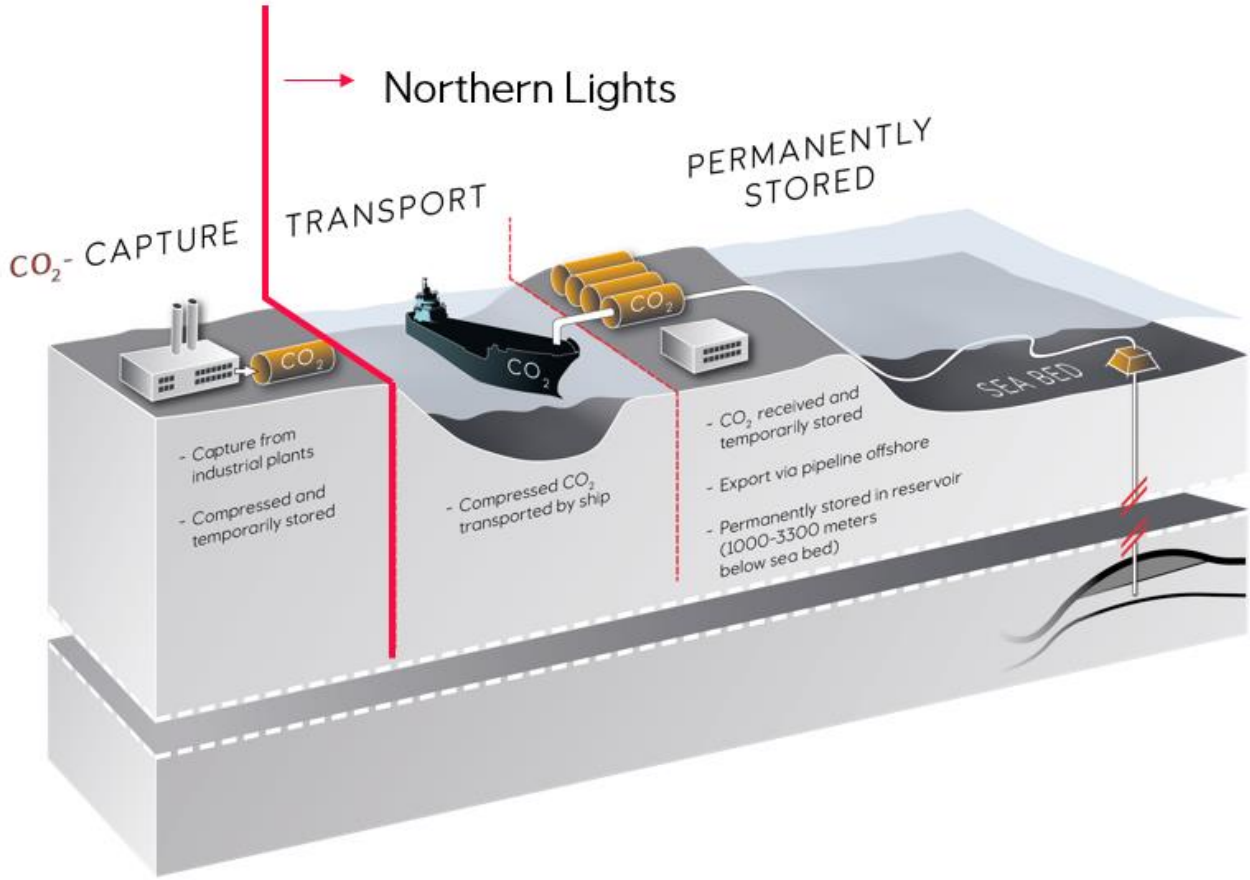


Figure 2-1 Northern Lights project as part of the Norwegian CCS demonstration project

The Northern Lights concept is based on Gassnova's design basis for the demonstration project, with flexibility to include additional volumes from 3rd party customers with incremental investments for increased capacity. The ability to develop both commercial and technical solutions attracting additional customers is a key success factor for the project. This is also required to meet the government's ambition with the demonstration project, establishing Norway as a safe storage for CO_2 from Europe.

A schematic of the concept building blocks with an indication of design capacities and flexibility for future expansion is shown in Figure 2-2.

As a “first of a kind” demonstration project it is expected that the onshore facility will receive a significant number of visits, from both industry, NGO’s and authorities. Both the Norwegian State and the Partner companies will want to showcase the facility and its function.

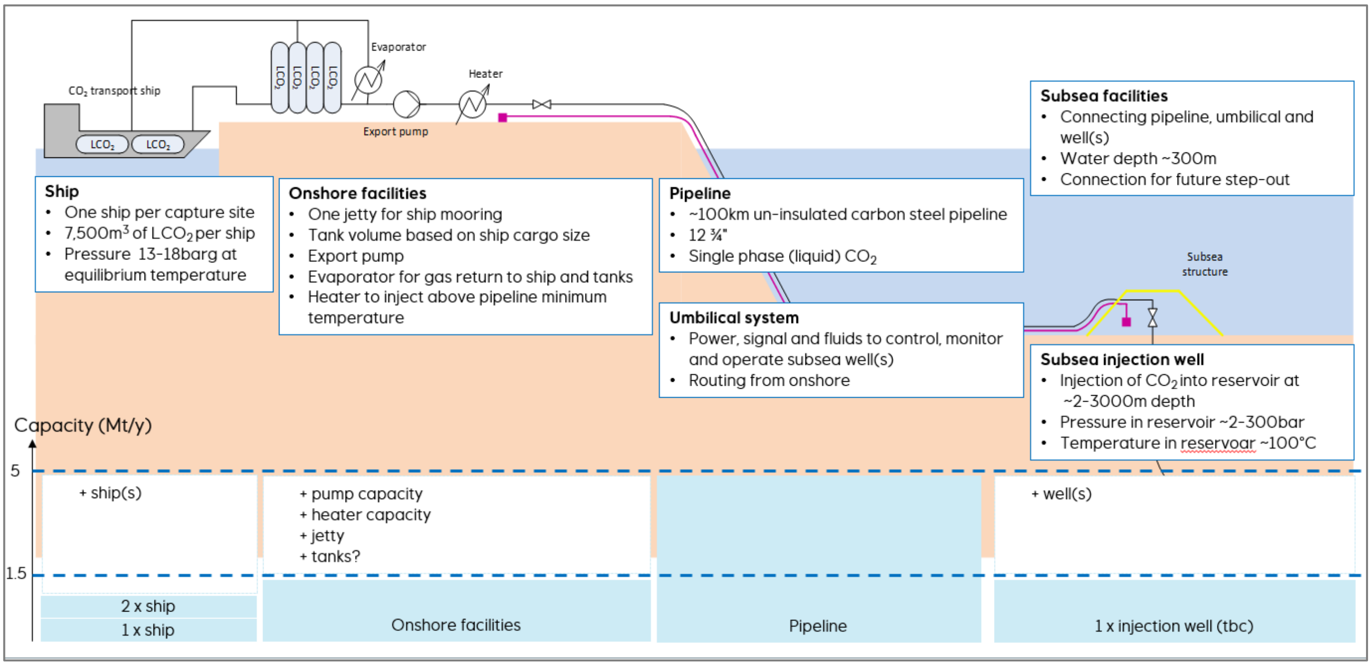


Figure 2-2 Northern Lights concept building blocks with capacities in the first phase shown with blue shading.

The project is developed in accordance with Equinor Management System.

2.2 Development from Contract Award

Equinor was awarded the Study Agreement in June 2017. The key developments in the study scope since award are:

- Storage complex changed from Smeaheia Alfa/Beta to Aurora. The consequence of this change is additional work for subsurface, and a need for a confirmation well to document the presence and quality of the reservoir section. Facility scope is affected since the new location is further from Naturgassparken (i.e. longer pipeline), and the reservoir pressure is higher due to increased reservoir depth.
- Ship transportation added to the base scope for Equinor. This has allowed optimization of ship size versus storage capacity, as well as the number of ships required.
- Overall study schedule aligned for all participants, i.e. FEED studies will conclude Q3 2019 for both capture and storage.
- The number of Capture facilities is reduced from three to two due to Yara no longer being part of the overall project. This has limited impact on facility scope since the design capacity is agreed to remain at 1,5Mt/y. It reduces the number of ships needed initially from three to two.
- The ship design has been changed from a “special design” developed by Gassco, to a standard LPG ship design, with a tank solution suitable for medium pressure CO_2.
- A flexible subsea configuration has been selected, to allow for uncertainties in the storage complex.

- The initial confirmation well will be drilled as a “keeper” (i.e. injection well).
- Cost estimates are established and show a moderate increase for the offshore facilities scope – primarily due to the longer distance to the Aurora storage complex. Onshore facilities and ship scope show a reduction, both through optimization and by elimination of one ship.

2.3 Project main milestones

Table 2-1 shows the main milestones for the project.

Table 2-1 Main milestones

Milestone	Date
FEED report (M10)	August 2019
Draft PDO (M11)	August 2019
State FID	Q2 2020
DG4	Q4 2023

2.4 Market assessment

The plan is to enter the supplier market primarily in the period 2019 to 2021. A wide range of supplier markets will be approached (shipping, onshore facilities, subsea facilities, umbilical system (DC/FO), pipeline, marine installations, rig etc) and the market developments may vary from segment to segments as they have different drivers. The project is and will continue to follow the anticipated market development within the relevant segments.

2.5 Pre-investments

All pre-investments are linked to the confirmation well which is planned to be drilled before State FID. Pre-investments are not covered by current agreements with the State. The pre-investments are however expected to be included in the final investment costs forming the basis for a state subsidy agreement.

2.6 Risk summary

A formal risk management process has been used during the concept phase. There has been continuous focus on assessing the threats and opportunities which make up the overall risk picture for the project. The risk picture is dynamic, reflecting the results of mitigating actions and new opportunities and challenges in the project.

The following risks are highlighted at end of the conceptual study:

Technical

- The uncertainty related to storage capacity of the Aurora storage reservoir (storage volume and injectivity). A validation point for Aurora (AVP) will define ranges/probability and recommend an optimal well location for the 1st injector at end of March 2019.
- Risks for late changes in the Design Basis due to updated knowledge of the Aurora reservoir at AVP. These are likely to mainly affect pipeline and umbilical routing, and FEED maturation has been planned to ensure robustness to outcome at AVP to a large degree. Ship and onshore scopes are likely unaffected by AVP.
- Tight schedule due to need for Aurora confirmation well before partners investment decision and subsequent parliament process. Limited ability to manage unforeseen events and outcomes from confirmation well and subsequent SSVP.
- Results from confirmation well could lead to change in reservoir location.
- Developments in capture projects outside of Northern Lights control, delaying interface process.

Non-technical

- Impact on overall schedule due to changes in capture projects or political processes.
- Challenging commercial model/contractual terms for execution and operation phase of project. This may lead to inability to establish JVA to take partners investment decisions.
- Lack of material 3rd party business opportunities at the time of investment decisions.
- Alignment with the Troll license. The Aurora reservoir is near the Troll area and an alignment of potential conflicts between production licenses and exploitation licence is important.

Execution scope and schedule reflects activities that are normally performed by Equinor and partners. Therefore, specific execution risks will be matured further in the FEED phase, while focus at this time is on bringing the project to investment decision.

2.7 Future business potential

The business potential for Northern Lights consists of three dimensions with increasing scope, and hence also increasing potential and uncertainty:

- Northern Lights itself, including expansion.
- Enabler for future CO_2 transport and storage business.
- Enabler for low carbon energy carriers and other value chains.

Northern Lights will establish the world's first large scale "open source" infrastructure for receiving and storing CO_2 from multiple sources and industries. This openness and flexibility is the unique value of the project, as other CCS projects only can be accessed by one or very few CO_2 sources. It makes it possible for any industrial actor that is close to sea and within reasonable shipping distance from Øygarden to get started with carbon capture at industrial scale. There are about 250 such industrial sites. The "open source" nature makes Northern Lights an excellent platform for initiating and maturing concrete CCS relationships with countries and companies that can result in 3rd party volumes for Northern Lights as well other future CCS projects.

Northern Lights' business potential will be determined by the quality and cost of the project, the commercial agreement between the partners and the state, and the success in securing additional 3rd party CO_2 volumes at adequate tariffs. The project and partners are working hard to secure success on all three dimensions.

The work on sourcing 3rd party CO_2 volumes is structured around a business development funnel which is regularly updated and revised. It begins with a desktop overview of promising CO_2 sources in Europe. From this overview a shortlist of promising companies and sites is identified, with which the project initiates dialogues. The Project has ongoing and concrete dialogues with 13 potential 3rd party customers, located in six countries. These are matured trough a range of approaches, e.g. joint research projects and commercial dialogues.

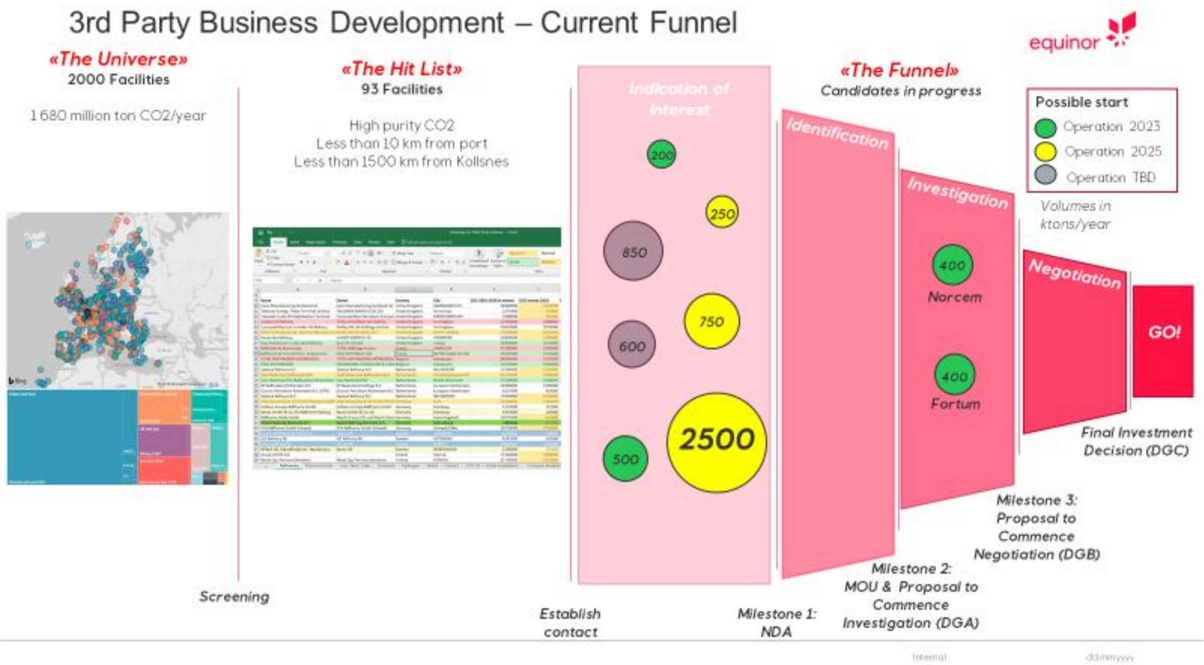


Figure 2-3 Third party business development funnel with some of the possible volumes

The sourcing of 3rd party volumes includes more than "normal" business and project development. This is also about developing markets and frameworks. All 3rd party opportunities hence need to be matured along three main axes:

- Company to Northern Lights
- Company to home country
- Companies' home country to Norwegian authorities

Key issues in the last dimension are London Protocol, ETS credits and long-term liability. It is envisaged that Northern Lights and Gassnova often will open 3rd party opportunities together. Gassnova will then be the main contributor on the country axes.

Northern Lights has developed principles and guidelines to secure that the 3rd party work is done in compliance with competition law. Establishment of "clean teams", for those people who are sharing non-public information with and from 3rd parties, is part of this.

The business potential beyond Northern Lights will largely be determined by how strongly countries and companies drive CO_2 reductions, and the role which CCS is given in their "tool boxes". The outlook is presently somewhat confusing. On one hand are leading bodies such as IPCC and IEA clearer than ever that CCS is absolutely needed rapidly and at scale. Several countries also highlight CCS in their Paris agreement action plans. On the other hand do some European policy-makers and NGOs seem ready to rule out CCS as a climate mitigation tool. Their arguments are that CCS is not proven and available, often combined with unrealistic expectations about what other solutions can deliver. It will hence be of outmost value that a successful Northern Lights demonstrates the practical feasibility and attractiveness of CCS to many stakeholders, thereby helping to secure that CCS is broadly utilized. If so, the business potential for CCS is very large.

The Partners develop CCS as a business through the double track approach described above: project development and policy advocacy. Many activities are done jointly, e.g. advocacy with EU and national governments through platforms such as ZEP, IOGP and OGCI. Project development is sometimes done individually, but often also jointly, e.g. as through OGCI.

Establishing CO_2 transport and storage will enable the development of new low carbon energy carriers. Key options are low-carbon hydrogen produced from natural gas with CCS, and emission-free power produced by combustion of gas, biomass, waste, etc. with CCS. One example is Equinor's hydrogen agenda. These are large-scale projects that integrate CCS and aim to address CO_2 emissions related to power production, industrial activities and heating.

CCS is also the crucial enabler for process industries to be able to transition to emission-free products, such as cement, fertilizers, metals or other products. Industrial sector emissions currently represent some 20% of the EU's total GHG emissions. Reaching net zero emissions by 2050 is impossible if industrial emissions are left unaddressed. CCS is also needed for achieving negative emissions through so-called "bio-CCS". The Swedish government has signalled clear interest in this.

3 Project description

3.1 Health, Safety and Environment (HSE)

3.1.1 Introduction

During the Northern Lights study phase up to this report, studies have been placed to suppliers covering the plant development, the associated civil development and the transport pipeline. SSU scope of work has been embedded into these studies. The respective contract responsible has ensured that the suppliers delivers according to Equinor's SSU requirements. SSU personnel (technical safety, environment, working environment and impact assessment) have supported these processes and typical deliveries from the vendors are e.g.

- CO_2 dispersion analysis
- BAT analysis
- Concept risk analysis
- Design reviews as HAZID, WEHRA and ENVID

To support the zoning plan development, the impact assessment and the environmental risk assessment suppliers are engaged. In addition, internal SSU scope has been carried out, e.g. tolerance criteria for concept phase, safety strategy and security study. Related to authority processes the zoning plan and impact assessment processes are started and for permitting processes e.g. an application for exploitation of a subsea reservoir for CO_2 injection and storage is issued.

3.1.2 Safety

Technical Safety and development of safe design in the project is based on relevant regulations, codes and standards, risk analysis, and design and barriers to prevent, control and mitigate the identified risk.

Since Equinors technical requirements to a large degree is focused on managing risk coupled to hydrocarbons (fire and explosion risk), several of the requirements are not applicable. However, general requirements related to risk assessment, establishment of safety strategy and performance standards, risk reduction principles and inherent safety, ALARP principle are valid. Elements in several of the performance standards such as safe containment, natural ventilation and HVAC, gas detection, ESD, process safety and PAGA/alarm systems, EER, safe layout are relevant. Requirements related to ignition source control, fire detection, flaring, active and passive fire protection, explosion barriers will only to a very limited degree be relevant.

3.1.2.1 Hazards of CO_2

The main safety risk for the Northern Lights facilities is large releases of CO_2. CO_2 is not classified as toxic substance; however, it has a neurological impact on humans. Like nitrogen, carbon dioxide will displace oxygen. But unlike nitrogen, people would be at severe threat from increasing CO_2 concentrations well before they would be in danger because of reduced oxygen concentration. Too high concentrations of CO_2 will be life threatening.

Liquefied CO_2 released to atmosphere from elevated pressure will form dry ice. The resulting cloud is extremely cold, lower than the boiling point temperature -78.5°C, until all solid particles have evaporated, and can cause frost injuries/cold burns to exposed personnel. This can also pose a threat against equipment integrity.

In case of loss of pressure from liquified conditions there is also a risk that solid CO_2 (dry ice) might cause clogging of equipment, including PSV valves.

Free water in CO_2 leads to a corrosive fluid. CO_2 is also a very effective solvent, and this needs to be addressed in material/component selection.

3.1.2.2 Risk analysis in concept phase

Qualitative risk assessment was included as part of the Hazid studies for the onshore facilities and the pipeline and compared to Northern Lights tolerance criteria for the concept phase. These criteria are based on the risk matrix in RM100 (Risk management in Equinor).

Safety in design and safety barriers to mitigate these hazards are briefly described in the next chapter, referring to the safety strategy for Northern Lights.

No red/high risks were identified, but some hazards were identified such as:

- Large CO_2 leaks causing
  - hazardous/lethal concentrations at significant distances
  - Dispersion of very cold gas (close to the release source the temperature might be lower than -78 ^oC
  - Lack of oxygen/unintentional stop in machinery or vehicles based on combustion because of large CO_2 leak
  - Loss of visibility because of dry ice and condensed water in case of a release of CO_2. Even if the concentration of CO_2 might not be fatal this might be a hazard connected to escape from the exposed area
  - Clogging of process equipment and PSVs by dry ice leading to the risk of equipment overpressure
  - Dry ice projectiles during maintenance and opening of equipment
  - Accumulation of CO_2 in low points/low lying areas

- Large leaks from subsea pipeline with the risk of exposing ship traffic, intervention vessels or nearby cabins
- Release of cryogenic liquid with risk of brittle fraction of materials
- Fire in electrical systems and other flammable materials
- Fire in systems containing flammable chemicals (Utility, MEG, hydraulic fuel, transformer oil)
- Falling objects that causes damage to process equipment or structural damage
- Dropped objects whilst transferring goods to ship leading to leaks of CO_2 or ship fuel
- Collision from CO_2 vessel that causes damages to the jetty
- Fire on the ship when located at the jetty
- Fire in office buildings
- Total power black out

Risk contours as basis for safety zones around the onshore facility and onshore part of the pipeline has been calculated for determination of safety zones as input to the regulation plan and compared to acceptance/tolerance criteria suggested by DSB. The results show that the risk is acceptable related to the DSB acceptance criteria: The proposed site location within the Naturgassparken is already designated for industrial development and the results indicate that the neighbour industrial/business facilities (i.e. fish farm, LNG plant) are located outside of the 10^{-5} per year contour, thus with acceptable risk levels. There are no residential areas or cabins within any of the contours. The risk contours will be updated during FEED, taking into account more detailed input including location specific topography and wind data.

The pipeline Hazid that was performed in concept phase was carried out with Smeaheia as the storage location. Hazid will be carried out in FEED with updated pipeline and umbilical routes to the new storage location. Major changes in results related to hazard potential or risk levels are not expected. In the next phase of the project, quantitative risk analysis will be carried out and compared with project specific quantitative acceptance criteria, to verify that the risk is acceptable also for plant personnel and with respect to main safety functions.

Even if high concentrations in the event of a major CO_2 release can occur at significant distances, it is expected that the plant will have an acceptable risk level compared to risk tolerance criteria. This will be further analysed in the quantitative risk analysis in FEED, according to normal project development. Risks depend on both probability and consequences of hazards, including the effect of risk reducing measures.

3.1.2.3 Safety strategy for the Northern Lights project

Safe design and safety barriers to prevent, detect, control and mitigate the hazards are described in the Safety Strategy, RE-PM673-00017, and are briefly summarised below:

- Storage tanks and pipeline landfall area located at the opposite side of the site from the administration building.
- The administration building is located at a higher level than the storage area.
- Design of containment/equipment to safely process and store the CO_2, based on recognised standards.
- Different means of gas detection to detect leaks early.
- Process safety surveillance and systems for detection and mitigation of hazardous process conditions
- Pressure relief systems
- Emergency shutdown
- Alarm and communication systems for emergency situations
- Emergency procedures
- Personal protective equipment
- Safe haven/gas protected area in administration building (dependant on further risk analysis in FEED)

3.1.3 Fishing and anchoring restricted zone

In the nearshore area in Hjeltefjorden, only lighter fishing gears are used, with a low potential of causing damages to the pipeline. In the offshore section of the pipeline and umbilical routes, there are intensive fishery activities by use of heavy bottom trawling gears, as indicated in Figure 3-1 for 2017.

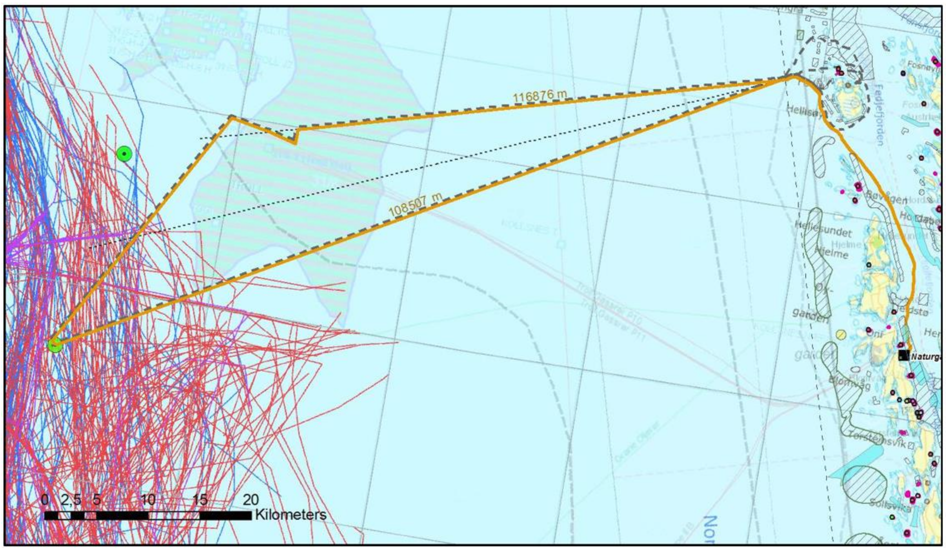


Figure 3-1 Bottom trawling activity 2017, based on satellite data from the Fishery Directorate.

As a general authority requirement, all subsea facilities and pipelines shall be designed to withstand heavy trawling activity. This is described in the Framework regulations, section 45, 2nd paragraph. *("Subsea facilities and pipeline systems shall also be designed and installed such that the facilities can withstand mechanical damage caused by other activity, and such that they do not damage fishing gear or obstruct fishery activity to an unreasonable extent.")*

According to Section 53 of the Framework regulations, the Ministry of Labour and Social Affairs can establish safety zones around and above subsea facilities with the exception of pipelines and cables. Normally such safety zones need an application to the Ministry. Furthermore, section 55 states that "*Prior to making a decision in accordance with Sections 53 or 54, an evaluation of the various interests affected shall take place. In this evaluation, the emphasis shall include which consequences the establishment of, alterations to or cancellation of such zones can represent to the conduct of the petroleum activities and other activities. Furthermore, which restrictions will apply in the safety zone shall be assessed and clarified."* These aspects should normally be addressed in the impact assessment for the project in case this kind of restriction area are considered for the project in question.

The content of the referred Section 53 corresponds with the Section 10-4 (Safety zones, etc.) in the Regulations relating to exploitation of subsea reservoirs on the continental shelf for storage of CO_2 and relating to transportation of CO_2 on the continental shelf ('CO_2 storage regulations'). The CO_2 storage regulations are referring to the Frame regulations on issues related to health, safety and the environment for all topics where the authorities find this relevant and applicable.

The areas relevant for subsea facilities is too deep for ordinary anchoring. The subsea facilities should be designed and installed in accordance with the requirements of section 45 of the Framework regulations. Due to the high trawling activity, it is not likely that an application for a fishing restricted zone will be granted by the Ministry of Labour and Social

Affairs. There is no legal authority to establish safety zones around or above pipelines and cables. It is not planned to apply for a fishing and anchoring restricted zone for the subsea facility areas.

The risks related to ongoing and future fishing activity combined with no restriction zones is fully considered, and trawling load studies have been performed. The studies are used as basis for further development of design of subsea facilities, including pipeline, and the corresponding protection philosophy. Adequate protection philosophy and measures will be implemented to obtain that the facilities will withstand the loads in question and be fully designed and installed in compliance with authority regulations and internal requirements.

3.1.4 Health and Working Environment

The Working Environment (WE) activity on the project has been governed by the Norwegian regulatory regime and Equinor Company requirements.

In line with a policy of inherent safety, the order of priorities in the design has been: to eliminate hazards, separate people from these hazards, or minimise the risk posed.

A Working Environment Health Risk Assessment (WEHRA) workshop was held to identify, evaluate and prioritise the occupational health risks in the facilities design as early as possible. The WEHRA considered 34 WE items on or in the operation of the facilities, for which the risk was assessed. CO_2 exposure and material handling were the most frequent identified hazards with seven, followed by six for working at height and five for electric shock. The WEHRA will be updated and further developed in the FEED phase.

Working environment area limits (WEAL) have been established and will be continuously updated throughout the coming design phases.

Noise modelling for the site including modelling of noise from Pressure Safety Valves (PSVs) was done using Softbits' FLARESIM package. Noise predictions through modelling will be updated and further detailed and developed during the FEED phase. Further, follow-up of the acoustic design and noise mitigation at the administration building and associated storage and workshop building will be done.

Relevant human factor analysis will be performed in the coming design phase. Likewise, the FEED phase will include chemical risk assessment, climate risk assessment, job hazards and ergonomic task analysis, radiation and electromagnetic fields risk assessments, and illumination predictions.

The Liquid CO_2 supply ship loading and unloading with other items, for example of provisions, is currently uncertain. These requirements must be defined, and a mechanical and manual handling review should be undertaken.
Liquid CO_2 Storage Vessel Pressure Safety Valves (PSV) are currently located on the top of the storage vessels. There are several safety (e.g. CO_2 release and associated noise), WE (e.g. working at height and weather exposure), material handling (e.g. removing PSVs) and operational aspects (inspection and maintenance) that must be investigated and an optimum solution established. The use of alternative means of inspection, e.g. drones should be investigated.

Renewing of storage tank surface protection should be analysed to minimise working at height and chemical exposure. WE factors shall also be considered in further detail for electrical and HVAC rooms through design reviews.

3.1.4.1 Results from WEHRA workshops

A Working Environment Health Risk Assessment (WEHRA) workshop was held at KBR to identify, evaluate and prioritise the occupational health risks in the facilities design as early as possible. The WEHRA considered 34 WE items on or in the operation of the facilities, for which the risk was assessed. There were no ‘unacceptable’ (rank 3) risks and the 2 ‘unknown’ risks (rank 4) are those where the hazard or exposure level is totally unknown.
Where controls were not evident or were considered deficient for the hazard and / or risk, 19 actions (and action responsible) were agreed to suggest or develop design alternatives to provide the necessary mitigation. CO_2 exposure and material handling were the most frequent identified hazards with seven (7), followed by six (6) for working at height and five (5) for electric shock. The WEHRA will be updated and further developed in the FEED phase.

Multiconsult arranged for a Constructability HAZID and ENVID. The HAZID revealed 62 hazards / problem areas, of which some involved working environment risk aspects:

- Work in steep terrain. Risk of machinery overturn.
- Noise exposure
- Dust exposure
- Work close to the sea front. Risk of falling into the sea and machinery overturn
- Diving operations
- Working at height
- Heavy wind exposure

The risks will be managed further in the FEED or Construction phases. The HAZID shall be updated and followed-up through the next design phases.

3.1.4.2 Results from Noise studies

Noise modelling for the site including modelling of noise from Pressure Safety Valves (PSVs) was done using Softbits’ FLARESIM package. Noise predictions through modelling will be updated and further detailed and developed during the FEED phase. Further, follow-up of the acoustic design and noise mitigation at the administration building and associated storage and workshop building will be done.

A computational model was used for the assessment, from which the noise predictions are presented in the form of noise contours and show that the project’s proposed noise limits will be achieved. They are predicted to range between 40 – 80dB(A); the lowest approximately 1.2km away facing north-west from the site, and the highest within the site in proximity to the Air Dryer and Air Compressor packages.

The assessment has also shown that there is unlikely to be a requirement for hearing protection within the site fence line, as noise levels should not exceed the 80dB(A) first action level for hearing protection. Noise levels resulting from the development on the south sea facing side of the site will not impact local fishermen. The highest noise level predicted here is 70dB(A). Marine noise, construction noise and architectural acoustics will be assessed separately as the project advances.

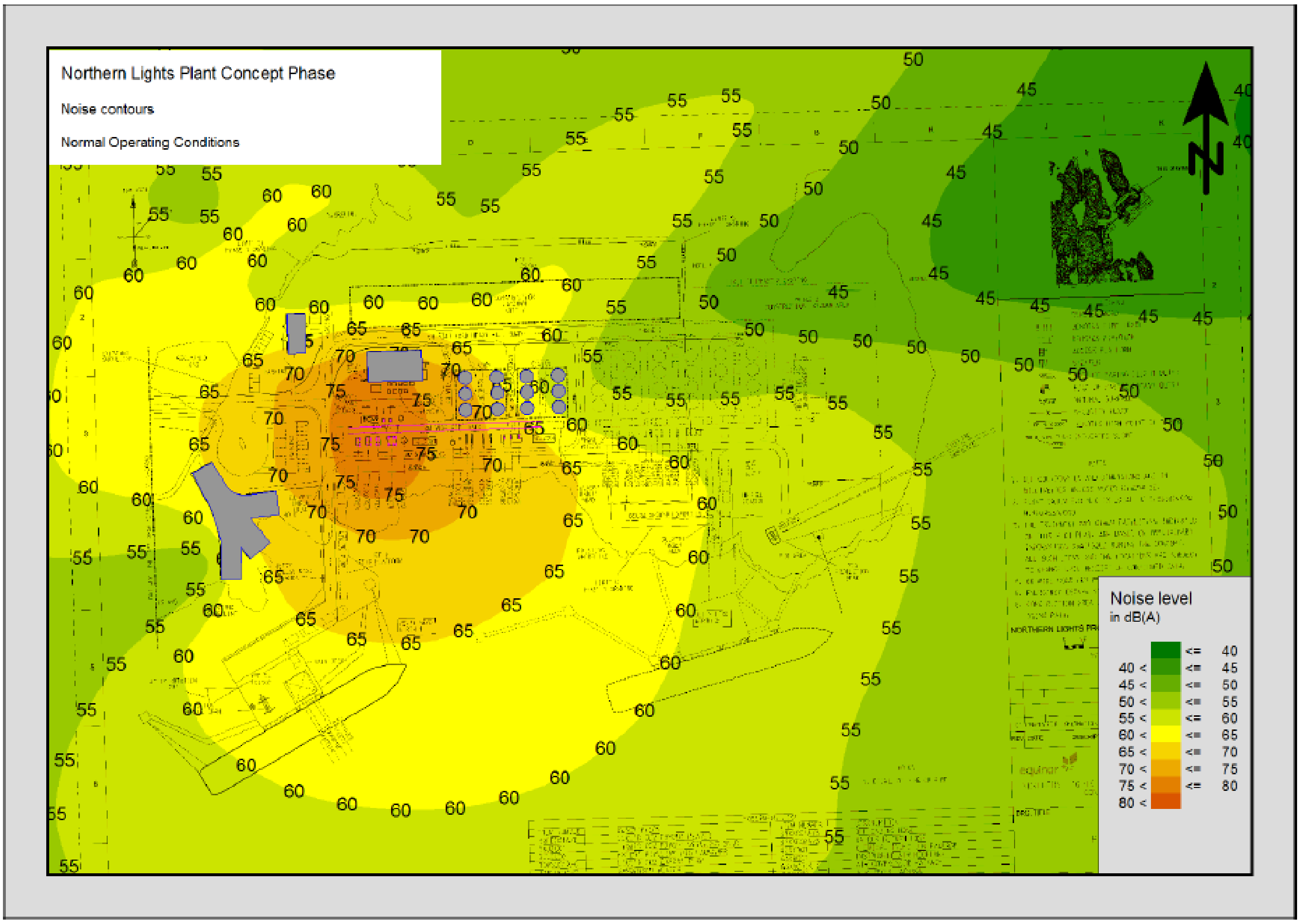


Figure 3.1.4.1 Noise contour map of the Northern Lights site.

Multiconsult revealed some noise aspects during construction in the constructability Hazid, as described in chapter 3.1.4.1.

3.1.5 Environmental aspects

3.1.5.1 Environmental budget

A preliminary environment budget of the land facility has been calculated for the base case design. This budget is not considering construction and materials. The total CO_2 footprint emission of the land facility is estimated to be approximately 2000 t/year. This is a very rough estimation including direct (diffuse emission and venting) and indirect emissions (power demand). These numbers will be refined during FEED phase.
There is no closed drainage system design for at the land facility as there are no operational discharges to sea. To prevent spill to the external environment, bunds are to be installed around transformers. Waste waters from the administration and visitor complex will be routed to a municipal sewer.

Table 3-1 summarise the estimates for aqueous discharges.

Table 3-1 Estimated aqueous discharge

Drainage Water	Quantity	Units
Volume	40,000	m^3/yr
Oil Content	0	mg/l
Oil Discharge	0	t/yr
Black and Grey Water		
Personnel	50	-
Discharge Factor	50	l/d
Discharge	913	m^3/yr

Wastes from the onshore terminal are expected to be from the administration and visitor building, and from maintenance activities. The latter is currently unspecified, but it is expected to be relatively low compared to a traditional oil and gas facility. Wastes from normal operation of the terminal is unlikely to exceed 100 tonnes per year. However, this will be further detailed during FEED.

3.1.5.2 Environmental aspect and best available techniques

The environmental aspects and impacts associated with the project have been identified though ENVID workshops. These workshops are an integral part of the process to identify potential environmental and societal aspects of a project and their management to reduce any potential impacts to As Low as Reasonably Practicable (ALARP). The ENVID covered the main development phases of the project (construction, installation, pre- and commissioning, and operations). The main findings from these workshops are registered in environmental aspect and impact register (Land facility; ref. KBR), constructability and Hazid report (Site preparation; Multiconsult) and Hazard risk register (Pipeline; Saipem). All key environment aspects for the land facility were reviewed and evaluated using a Best Available Techniques approach (report KBR). The primary focus of a BAT study is on design and technical solutions to meet process demands whilst minimising material consumption, wastes, energy emission and other relevant environmental parameters.

There are no high-risk environmental aspects (red level) identified within Northern Lights project.

Regarding operation of the land facilities two significant risk aspects (orange level) are identified:

- Energy consumption of electrical heaters for CO_2 export
- Unplanned events requiring venting of stored CO_2

Storage vessels, main vent CO_2 recovery system and export heating were further evaluated under a BAT study to minimise the risk level identified above. The main conclusions from the study are presented below:

- Storage vessels and main vent CO_2 recovery system: the need to avoid solid CO_2 formation in the pipework and the need for multiple, local vents probably makes the use of a recovery system impractical. A refrigerated loop in each storage vessel will counter heat ingress and prevent boil off but will not prevent losses from leaking valves, maintenance or vessels testing requirements. The added cost of the refrigeration or gas recovery system would be offset by the value placed upon losses of CO_2 which would otherwise occur CO_2 emission taxes. Without of the benefit of a more detailed analysis the current view is that there is no economic benefit for refrigeration or gas recovery.

- Export Heating: Reducing heat specification is a measure which could save energy and should be evaluated for future development of the plant. Direct heating using seawater or heating via heat pumps would use proven equipment but a design for CO_2 heating has not been developed and assessed for this phase. A simple electrical heating system is favoured

Marine discharges, land impacts, disturbances of local surrounding community and wastes are ranked as low to medium risk (green to yellow). These aspects will however require further evaluation under construction as part of the Construction environment management plan.

3.1.5.3 Monitoring plan for calculating and measuring quotas bounded emissions

The quotas bounded emissions related to transport and storage of CO_2 in a geological reservoir shall be monitored and reported as per regulatory requirements. These requirements are rooted in:

- The European Parliament and Council directive 2009/31/EC on geological storage of carbon dioxide
- The European Parliament and Council directive 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community
- The Commission regulation (EU) 601/2012 on the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC

These directives and regulation are adopted and integrated in the Norwegian regulation framework and their compliances are controlled by the Norwegian Environment Agency (NEA) through, amongst other things, attribution of permits: permit for injection and storage of CO_2 and permit to quotas bounded emission of climate gas with monitoring plan.

The quotas bounded emissions permit with monitoring plan is describing and regulating the activities subjected to quotas, the associated source streams, the monitoring methodologies for determining source streams emissions (calculation-based or measurement- based) and the associated uncertainties. The monitoring plan include also monitoring of the CO_2 quantity injected in reservoir with associated measuring methodology. Where measuring equipment are involved, they are listed together with their tag numbers, operational ranges, specific uncertainties and maintenance program. If sampling is required as part of the monitoring methodologies, a sampling and analysis plan must be developed with reference to analysis protocol/standards, sampling methodologies and laboratory. The monitoring plan shall also refer to the company management procedures and guidelines that will be relevant for performing, following-up and controlling the monitoring plan. It is obvious then that a monitoring plan cannot (and will not) be fully developed within concept or FEED phase; however, the main principles should be agreed upon during these phases.

The quotas bounded emission permit is a complex document which requires a good understanding of the installations and statutory requirements. It is therefore paramount to establish a close relationship with the relevant and competent authorities to obtain a permit adapted to the specificities of our future activity. The project had several meetings with the NEA to establish the ground for an effective collaboration and defined the frame of the future application for quotas bounded emission permit.

There are two valid permits on the Norwegian Continental shelf related to capture and storage of carbon dioxide: Hammerfest LNG and Sleipner permits. These permits are related to oil and gas activities with processing activities to extract, capture and reinject CO_2. The associated monitoring plans are comprehensive reflecting the complexity of the activities. As there are no processing activities related to CO_2 storage on the land facility, the scope of the monitoring plan for our segment of the CCS chain will be in comparison reduced). The NEA recommended however to use Hammerfest LNG permit as source of information.

The first step in establishing the monitoring plan is to define the monitoring boundaries of the installation submitted to quotas reporting. The scope of the Northern Lights project encompasses both transport of CO_2 via ship, temporary storage on land, and transport of CO_2 via pipeline to a permanent geological storage offshore. Ship transport is currently exempted from the quotas bounded emission regulation[1] and CO_2 transport via shipping is not covered by the CCS directive. The project working assumption is therefore to exclude CO_2 ship transport from the monitoring plan. This was presented to and discussed with the NEA. The agency agreed with this conclusion based on laws and regulation in place. The agency informed however their intention to develop a legal framework regulating the ship transport segment of the CCS chain in future national (if not European) regulation[2]. This will be follow-up closely.

The proposed boundaries for the monitoring plan are highlighted in Figure 3-2.

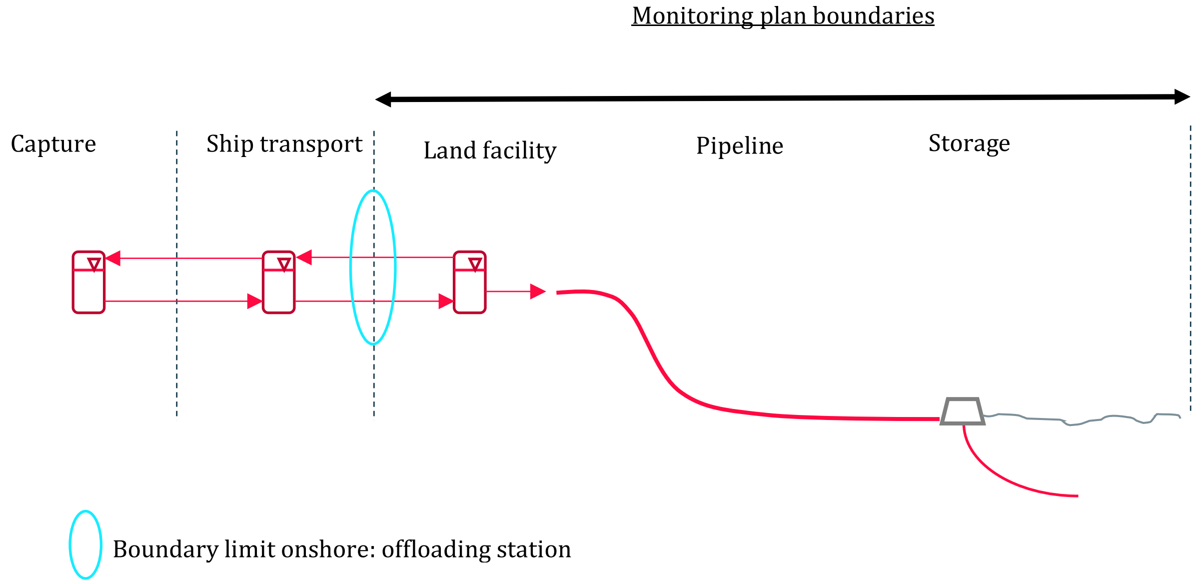


Figure 3-2 Sketch showing the monitoring plan boundaries

The second step is to map the potential emission sources within the monitoring boundaries of the installation. A preliminary screening has been performed and presented to the NEA to discuss monitoring methodologies and associated uncertainties.

The screening includes both normal operating conditions and upset conditions (accidental emissions) and is summarised in Table 3-2.

[1] The inclusion of shipping in emission allowance trading scheme was discussed as part of the preparatory work for amending EU/directive 2003/87/EC but this was not pursued. IMO is the organization responsible for setting emission reduction strategy and plan for shipping

[2] Preliminary feedback from the agency is that regulation related to CO_2 transport by ship and modification of London convention should be in place before allowing trans-frontiers transport of CO_2

The main operational emission source is related to offloading operation from ship to land facility. The other potential emission sources are those related to maintenance and fugitive emission. There is no operational venting related to CO_2 storage in the tank and as the land facility will be electrified there are no emission related to combustion of fuel for power generation.

The ownership of the emission related to CO_2 offloading from ship (within or outside our monitoring perimeter) was discussed with the NEA. The agency considered that any venting/leakages that happen in the interface between shipping and storage should be deemed to originate from storage facilities, not shipping. This remains however to be further discussed.

Regarding pipeline there is no vent box design for at the land facility as the project assumption is that the pipeline will be emptied only once in the lifetime of the installation during decommissioning. Accidental releases from pipeline subsea will have to be detected as part of the leak detection philosophy as theses emissions have to be reported.
Leakage risk assessment from the geological storage complex and wells (legacy and injector wells) are not yet completed and therefore not described here. However, based on experience from Snøhvit permit, it is expected that the monitoring program will have to be tailored made to the accidental release when/if taking place.

Table 3-2 Preliminary screening of potential emission sources at the land facility

Where	Operational mode	Emission types	Emission sources	Details
Ship/Land facility interface	Normal operation	Venting	Loading arms	Need for loading arm purge before each offloading operation
Land facility	Maintenance	Venting	Tanks	Number of event per year to be defined
			Booster pump	
			Heater	
			Export pump	
			Piping, valves	
			Instruments	
		Fugitive emission	Facility components	
Land facility	Upset condition	Venting	Tank	If injection stop > 5days
Pipeline	Accidental release	Subsea release	Pipeline	Detection limit dependent of the leak detecting system selected

The recommended emission monitoring methodology is the calculation- based methodology. This methodology consists in determining emissions from source streams based on activity data obtained by means of measurement systems and additional parameters from laboratory analyses or default values. This was discussed with NEA and is in line with their application of the regulations to existing facilities (Hammerfest LNG). The measurement systems to be used for estimating the amount of vented emissions are still pending further development of the metering and operation philosophies. The followings are under discussion: tank gauging tanks and material inventories.

Regarding CO_2 fugitive emission the use an Optical Gas Imaging (OGI) leak/no leak method as accepted by NEA in Hammerfest LNG permit (dated 23.02.2018). The method is based on establishing a database compiling all potential leakage sources at component level and on performing measurement campaign using IR specific camera to identify the ones leaking. Based on the results of these campaigns the proportion of leaking elements is established. This percentage is used in combination with leak/no leak factors established for defined leakage rates per components types (valves, pumps etc.)[3]. These factors are based on the detection limits of the camera. The frequency of the monitoring campaign is set up to once every third year at Hammerfest LNG site.

The monitoring plan shall also include a description of the measurement system accounting for the quantity of CO_2 injected. The regulatory requirement is to apply a measurement-based methodology for monitoring the transfer of CO_2. The type and location of the monitoring system are still under discussion. The measurement uncertainties of CO_2 liquid meter have been discussed with NEA in the lights of the regulatory requirement of maximum permissible uncertainties of +/-2,5%. The need for pre-qualification or proofing of meters was also highlighted.

3.1.6 Handling of Risk and Emergency Preparedness

An escape, muster and emergency response assessment has been carried out in the concept phase for the onshore terminal. Potential impacts of identified Defined Situations of Hazard and Accident (DSHA) that could occur at the terminal were reviewed and the arrangements in terms of personnel escape, protection and emergency response considered.

Based on the results from the concept studies recommendations related to handling of risk and emergency preparedness have been identified:

- Diverse and alternate escape routes from main equipment locations and buildings
- Illuminated wind direction indicators located at strategic site locations to advise persons of the prevailing wind direction. Wind vanes shall be visible from all areas at the facility
- Primary muster location will be a defined area within the administration / visitor building. The building should have an HVAC system and a gas protected area and entrances should incorporate an air-lock arrangement to support pressurisation and minimise ingress of CO_2 in an accidental event.
- Alternative muster locations to be considered for locations where persons may be isolated by a hazard event, e.g. at the jetty head or pigging location based.
- The provision of either protective shelters at strategic locations on the facility or emergency vehicle evacuation systems (e.g. electric carts) shall be evaluated in the next project phase as part of a broader escape and evacuation study
- PPE in process, storage and jetty area such as protective clothing covering legs and arms, hard hats, small air bottles, protective footwear and gloves, safety glasses and hearing protection
- Procedures for safe mustering and evacuation of visitors

3.1.7 Security

A preliminary security risk assessment has been carried out for Northern Lights project. In summary, it is envisaged that the project will have a positive effect on the environment, and thus risks related to activism are expected to be less significant. Conversely, local agitation and demonstrations may result, if it is construed that this project will distress the natural habitat and environment of the area. However, some of the highest risks are expected to be associated with

[3] «Leak/no Leak factors» are established by CONCAWE and reported in “Techniques for detecting and quantifying fugitive emissions”, CONCAWE report 6/15 October 2015

cyber-attacks by nation states and organised crime, resulting in disruption of services or theft of confidential information. Controls will be implemented to mitigate such. Relevant regulation is FOR-2013-05-29-538 “Regulation for Port Facility Security”; (in Norwegian “Forskrift om sikring av havneanlegg”). The regulation refers to the International Ship and Port Facilities Security Code (ISPS). In the FEED phase this topic will be further detailed.

3.1.8 HSE program

3.1.8.1 Annual Global People Survey (GPS) and reported incidents

During the concept phase a Global People Survey (GPS) on working environment has been carried out and two incidents originating from project activities, have been entered in Synergi.

The results from the 2017 GPS is divided into “High assessment” (75-100), “Medium assessment” (60-75) and Low assessment (0-59). A high number means positive results. On an aggregated level the results relevant for the project team, came out as “High” **five** out of seven instances and in **two** out of seven instances as “Medium”, but very close to a “High”. In all instances well above the Equinor project department average score and Equinor overall average. The result was presented to the project management team in December 2017.

In March 2018 a near miss was reported due to a project member who had to seek doctor after an event with a car.
In June 2018 a near miss was reported due to rope in the vessel propeller in connection with installation of a Metocean survey buoy. Both near misses classified as “Other undesirable HSE incidents”

3.1.8.2 Project specific objectives

1. The project shall be developed with focus on critical HSE elements such as impact assessment, risk analysis and cost effective technical solutions. The project shall strive to meet expectations from relevant authorities, partners and other stakeholders. As a "first of its kind" CO_2 storage facility, it is of paramount importance that the facilities are designed to ensure as low potential risk of CO_2 exposure to third parties as practically possible (in compliance with the ALARP principle).

2. The project shall have ambitious targets with regards to cost effective processes and technical solutions with negligible negative impact on HSE. The project shall contribute to industrialisation and standardisation resulting in reduced investment cost per CO_2 unit and secure that CCS becomes a relevant international climate tool for achieving necessary greenhouse gas reductions.

3. The project will focus on collaboration, sharing of experience and competence building together with authorities and partners. This is done to further develop CCS into a cost-effective climate tool and support the ambitions to strenghten Norwegian parties as internationally recognized and preferred collaboration partners. To facilitate such dissemination of knowledge, e.g. the onshore plant will include an information / visitor centre.

To succeed with this, it is important that:

- HSE evaluations are an integral part of all decisions related to technology process and equipment development.

- Project changes that may lead to changed assumptions or results with regard to HSE level shall be reported to the SSU Manager, so that relevant compensating measures can be implemented.
- The project will actively and openly communicate with relevant authorities, affected communities, interest organizations, and other stakeholders to understand their views and inform about HSE in the project.
- We ensure alignment with client and partners on values and goals and that our suppliers share our values and goals.
- We maintain and further develop a HSE culture characterized by:
    - Project workers who are confident that there is always time for carrying out their work in a safe and well-planned manner.
    - Focus on preventing injuries, work-related illness and major accidents, and the goal of zero accidents has become part of the way we think and work, with great emphasis on continuous improvement.
    - To contribute to sustainable development and use resources and energy efficiently when procuring our products and services.

3.1.8.3 Key activities towards project DG3

Table 3-3 Deliveries towards DG3 – High level timeline

Description of the table: The period from Dec. 2018 to Feb. 2020 is divided into three columns each five month. Grey colour indicates when activities most likely are carried out.	December 2018 - April 2019	May 2019 – September 2019	October 2019 - February 2020
Authority Relations			
Revise authority engagement plan			
Updating / detailing of legislation overview			
Plan & issue relevant applications to Authorities for drilling permit			
Plan, prepare & issue relevant applications to Authorities for discharge / emission / injection permits			
HSE Management			
Revise HSE program			
Revise HSE activity plan			
HSE register (internally and suppliers)			
Revise goals and requirements for HSE			
Contractor follow up to secure HSE requirements/activities in contracts			
Internal processes, activities & deliveries			
Impact assessment process			
Zoning plan process			
Risk tolerance criteria in FEED phase (Safety / Environment)			
Update Safety Strategy			
Perform SIL studies			
Update Security studies			
Supplier/contractor activities			
Environmental risk assessment & monitoring strategy			
Carry out workshops (HAZID, WEHRA, ENVID etc) with updated risk conditions and challenges and including interfaces between ship (when in harbour), onshore plant, pipeline, umbilical and civil development etc.			
TRA, other risk evaluation and dispersion calculations			
Emergency Preparedness Analysis / Strategy (incl Environment)			
Carry out HAZOP study			
Carry out ALARP processes when required			
Environmental budget and BAT assessment			

For complete Project specific HSE program, refer to PM673-PMS-020.

3.1.9 Authority plan

3.1.9.1 Ongoing assessments, processes and permits

Well-functioning relationships are established between the project and local, regional and national stakeholders related to assessments and authority processes, permits and regulation clarifications. On the local level the municipalities in Øygarden and Fedje are important, on a regional level; e.g. the County Council, the County Governor and the Directorate for Fisheries are important , and on a national level; Ministry of Petroleum and Energy (MPE), Norwegian Petroleum Directorate (NPD), Petroleum Safety Authority (PSA), Norwegian Environmental Agency (NEA), Directorate of Civil Protection (NDCP) and Ministry of Labour and Social Affairs (MLSA) are important stakeholders.

To secure right of way for the project development a zoning plan process is started. This covers the onshore areas for plant, harbour and building facilities and the pipeline and control cable routes in sea out to one nautical mile outside the sea boundary (Norwegian "grunnlinje). The areas are located both in Øygarden and Fedje municipalities with a combined zoning plan handling. The zoning plan program is approved in both Øygarden and Fedje municipality. The project is developing an impact assessment (IA) in two revisions; revision 1 to cover the Zoning plan area and revision 2 to cover the whole area affected by the project including the Aurora area. Hence the IA process supports the development of a zoning plan and a PDO/PIO production. The IA program was publicly consulted Q1 2018 with the initial storage area included and later an addendum to include the Aurora area in the IA program was publicly consulted Q3 2018. At the time of the report the IA program (including hearing comments) are being handled by MPE for their acceptance. Revision 1 of IA is expected to be issued as part of the zoning plan for first processing in municipalities within November 2018. The planned date for revision 2 of the IA to be sent for public hearing is Q2 2019 and it is expected to be issued to MPE together with PDO/PIO Q4 2019 for handling in the Ministry and in the Parliament.

See Figure 3-3 for the total zoning plan area at the time of the report.

Following the invitation from MPE to apply for CO_2 exploitation rights for the Johansen formation, an exploitation application for this area was issued from the project to MPE/(NPD) on 7 September 2018. A decision from MPE is expected Q4 2018.

The project has received several permits from the Norwegian armed forces to either collect new seabed mapping data or share existing or new seabed mapping data with specified suppliers.

The project has been in contact with MLSA regarding their responsibility related to CO_2 transport & storage Regulation. In April 2018, their responsibility was delegated to PSA. New information received from PSA late October 2018, however reveals that PSA only takes the responsibility for the CO_2 pipeline, subsea equipment and the well(s) and that NDCP takes the responsibility for the CO_2 plant.

Figure 3-3 Total zoning plan area in Øygarden and Fedje municipalities. Note that the Plan and building act requires that a CO_2 pipeline (with associated equipment e.g. control cables) is included in the zoning plan area in sea out to one nautical mile outside the sea boundary (no.:'Grunnlinje').

A new regulation with working name "CO_2 regulation on safety and working environment" referring to the "Continent Shelf Act of 1963" will be developed by PSA and is expected to be sent for public hearing within Q4 2018. The project will engage actively in the hearing process and keep in contact with PSA for consultations where necessary until the new regulation is published by MLSA / (PSA). The project will propose competence area meetings with PSA to show simplification and improvement proposals. The project will also continue the discussion with NDCP.

In Figure 3-4 ongoing processes are placed into a high level timeline.

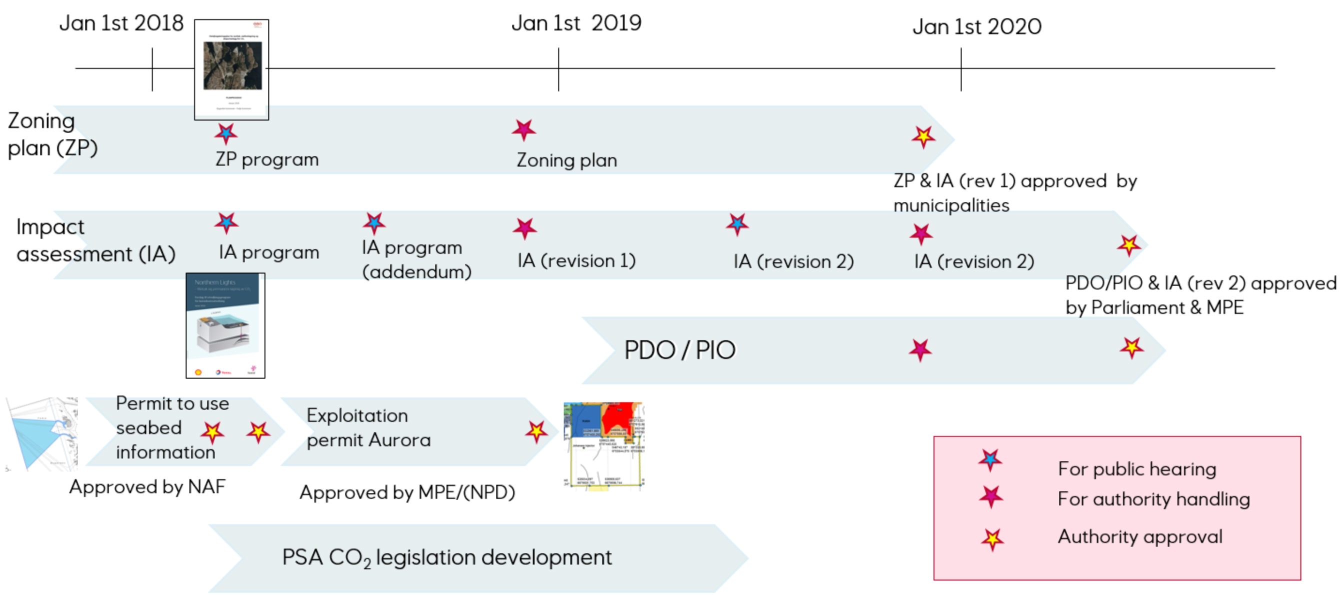


Figure 3-4 Ongoing processes (applications, permits, assessments and regulatory developments). For further details refer to PM673-PMS-009 Authority Management Plan.

3.1.9.2 Assessments, processes and permits

The processes for zoning plan and impact assessment will continue in the FEED phase. The need to share seabed mapping data are approaching an end and further applications will only be issued if new needs are identified.

The PDO/PIO process is expected to start Q1 2019 and the project plans to issue the PDO/PIO late Q4 2019. Refer to Figure 3-4.

The project has started the planning process for drilling a confirmation well in Q4 2019. The planning will follow standard authority process for drilling of exploration wells.

For further details refer to PM673-PMS-009 Authority Management Plan.

3.2 Design data

3.2.1 CO_2 volumes and specification

Two capture plants are included in the FEED phase of the Norwegian demonstration project. Expected CO_2 capture profile for the two plants are shown in table Table 3-4. Both plants plan to have a flat capture profile only varying according to revision stops with an indicated duration of two-three weeks per year.

Table 3-4 Production from capture plants

Capture plant	Annual target export volumes	Max production rate
Norcem	400,000t/y	56t/h
Fortum Oslo Varme	400,000t/y	56t/h

The design of Northern Lights facilities shall be able to handle supply from only one capture plant for an extended period.

The maximum capacity for the plant of 1.5Mt/y allows for 3rd party deliverables to fill up the capacity planned for in the first phase of the project.

3.2.2 Ship transport specifications for CO_2

CO_2 is transported in single-phase liquid.

CO_2 is transferred from capture facilities in ship cargo tanks at a pressure between 13 and 15barg, with corresponding equilibrium temperatures.

CO_2 is transferred from ship cargo tanks to onshore storage tanks at the Northern Lights terminal at a pressure between 13 and 18barg in the top of the onshore storage tanks, with corresponding equilibrium temperatures.

3.2.3 Specification of CO_2 fluid

For new sources deviating from the project CO_2 specification a risk assessment shall be performed to evaluate if there are any potential risks to the installations.

Table 3-5 CO_2 specification

Component	Concentration, ppm (mol)
Water, H_2O	≤ 30
Oxygen, O_2	≤ 10
Sulphur oxides, SOx	≤ 10
Nitric oxide/Nitrogen dioxide, NOx	≤ 10
Hydrogen sulfide, H_2S	≤ 9
Carbon monoxide, CO	≤ 100
Amine	≤ 10
Ammonia, NH_3	≤ 10
Hydrogen, H_2	≤ 50
Formaldehyde	≤ 20
Acetaldehyde	≤ 20
Mercury, Hg	≤ 0.03
Cadmium, Cd Thallium, Tl	≤ 0.03 (sum)

Non-condensable gases are components that, when pure, will be in gaseous form at 15barg and -26°C. The content of non-condensable gases will be limited by the actual solubility in the liquid CO_2 in the interim storage tanks at the capture plants.

3.2.4 Capacity and flexibility

The design basis capacities and strategy for future increase in capacity is outlined below for each part of the chain.

- Ship: The strategy is to optimise number of ships for the initial volumes. Currently initial volumes include volumes from the two capture plants in the Norwegian demonstration project, ref. paragraph 3.2.1. One ship with a cargo size of 7,500m^3 is planned for each capture plant. New volumes may require additional ships.
- Onshore facility: The onshore processing equipment (pumps, heaters) is sized according to design basis of 1.5Mt/y. Additional throughput will require additional capacity in processing equipment. Space and tie-in points for new equipment should be identified in the initial design.

- The onshore storage volume is based on a ship cargo size of 7,500m^3.. Additional storage volume could be required if ships with larger cargo sizes are introduced in the chain. Space for future storage volume has been identified.
- The import jetty is designed to receive ships of a size and frequency determined by the project. For future expansion a new import jetty no. 2 is required to allow for more, potentially larger ships or more frequent ship arrivals. A location for the future import jetty no. 2 has been identified.
- Pipeline: The pipeline is designed to allow for a future flow rate of minimum 4Mt/y based on a cost vs. benefit evaluation (actual capacity may be closer to 5Mt/y for the selected storage complex).
- Subsea facilities: The strategy is to use satellite wells, with tie-in points for future tie-in of new pipeline extension to connect to additional satellite wells.
- Wells: The strategy is to drill a minimum number of wells for injection of CO_2. For future expansion, additional wells may be required depending on reservoir performance.
- Subsurface: The strategy is to select a storage location giving a potential storage of at least 100Mt.

3.3 Material Philosophy

CO_2 is considered non-corrosive as long as it is dry. However, as soon as free water is present in combination with CO_2 it will form carbonic acid and be corrosive to carbon steel. CO_2 from capture plant will generally not be pure, and some of the impurities may affect the thermodynamic properties of CO_2 and have a negative effect on solubility of water Therefore, the amount of water present in the CO_2 needs to be well below the solubility level in dense phase CO_2 for the actual CO_2 composition, or one needs to select corrosion resistant materials or protect carbon steel with internal lining or cladding. Impurities in the CO_2 may also form corrosive compounds in combination with water, but CO_2-corrosion is considered to be the main threat to carbon steel.

The service in dense phase CO_2 is planned to be “sweet” under transport conditions and H2S is not expected to play a role in corrosion. However, it is prudent to consider if Sulphide Stress Corrosion Cracking (SSC) could occur. For the pipeline the equivalent partial pressure of H2S in the system will exceed the classical “NACE limit” for CS of 3 mbar. Therefore, it is required to design the pipeline for sour service

A high focus on water, oxygen and H2S content control of the CO_2 stream and strict procedures for loading and off-loading to prevent ingress of water and oxygen is essential to prevent internal corrosion damage to onshore facilities and pipeline. Monitoring of CO_2 composition should be performed to check that hazardous deviations from the gas composition specification do not occur. In addition, samples should be taken at certain intervals for lab testing. If the concentration measurements show increasing or unacceptable conditions the flow should be stopped, and actions taken to regain safe gas quality.

Even though there is a strict limitation on the water content there is a risk of corrosion in the lower parts of the well where formation water may flow back in case of non-continuous injection. Therefore, corrosion resistant alloys must be selected for water exposed parts of the well.

Brittle fracture is an important aspect for the applied materials of construction, concerning the temperatures during transport and storage of CO_2. All equipment must be designed for withstanding the conditions which may occur during shutdowns, start-ups or transient operations where the conditions may differ from steady state operations. Further is it important to consider the temperatures that could be attained during depressurizing, release or leakage of CO_2.

CO_2 pipelines are more susceptible to long running fractures than hydrocarbon gas pipelines because of the decompression characteristics of the gas. In ductile fracture propagation, the fluid saturation pressure, resulting from the sudden decompression of the fluid provides the crack driving force. To arrest a ductile fracture, the arrest pressure must be greater than the saturation pressure. Either the arrest pressure must be increased, or the saturation pressure must be decreased. Unlike natural gas pipelines, for CO_2 pipelines, it is possible to increase the arrest pressure by increasing the wall thickness and/or increasing the pipe material strength.

The calculations and numerical simulations of the Northern Lights pipeline base-case demonstrate that adoption of the Battelle two curve method with ISO 27913 or DNVGL RP-F104 arrest pressure corrections for CO_2 leads to a robust arrest assessment with significant margin to a critical wall thickness.

Non-metallic materials

Many polymers are susceptible to swelling and changes (degradation) in physical properties due to absorption of dense phase CO_2.

There may also be short-term exposure to methanol or MEG (most likely) during pipeline dewatering operations at start-up. Therefore, use of non-metallic materials should be avoided.

If one cannot avoid use of non-metallic materials qualification is required. Such a qualification needs to cover explosive decompression and swelling. In addition, low temperature properties must be considered.

Qualification shall be performed in accordance with NORSOK M-710 and NACE TM 0297-2008.

Polymers from various classes have been reported as suitable for liquid CO_2 service. There can be great differences in performance between the different elastomer formulations in the same general class. In general, thermoplastics provide better resistance in CO_2 compared with elastomers.

Chemical ageing is not considered a risk due to moderate temperatures and low level of species which can cause chemical ageing in the CO_2, such as H_2S.

3.4 Flow assurance

3.4.1 General

Analysis shows that operation in the two-phase condition in the transport system will involve challenges as:

- Unstable temperature variation
- Large slugging effect with large uncertainties in Olga simulation.
- Cavitation, flashing and steam hammering effects

Based on this, the strategy is to ensure CO_2 is transported in single liquid phase condition.

The reservoir pressure in the Johansen formation in the Aurora area is expected to be high enough to secure liquid phase condition at the wellhead for all operational scenarios and flowrates. This allows the subsea choke to be used to secure single phase operation in the pipeline for small flowrates.

3.4.2 Results by Olga simulations

Pipeline pressure and capacity

Pipeline transport capacity will depend on the wellhead pressure, pipeline length and the export pressure from the onshore facility. A 12 ¾" pipeline was selected to secure future volume capacity. Figure 3-5 shows the transport capacity assuming 100km 12 ¾" pipeline and different wellhead pressures and onshore export pressures. A pipeline design pressure of 290bar has been selected, this will secure future capacity of 5Mt/y.

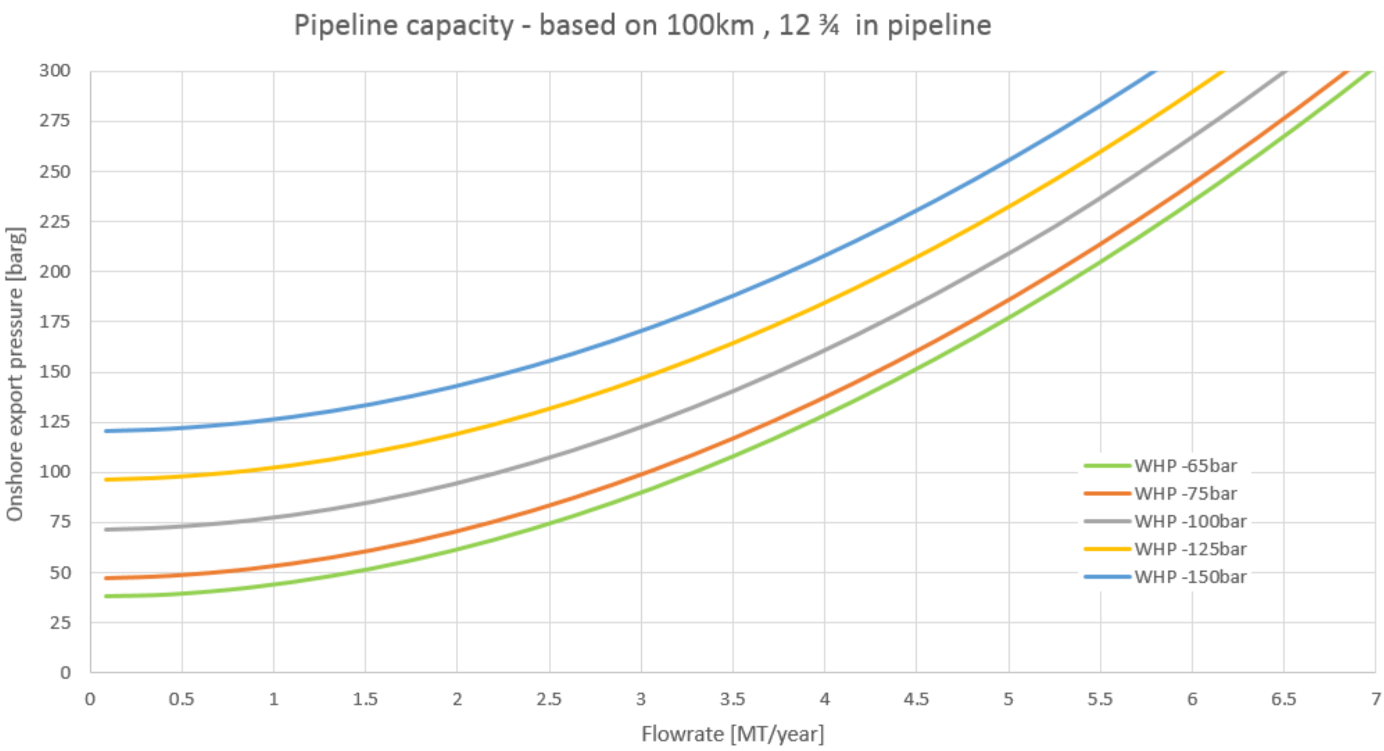


Figure 3-5 Pipeline transport capacity

Transient operation of the system.

A shut-in well will result in increasing wellhead pressures due to heating from the ambient formation. This may result in higher pressure in the well compared to the pipeline shut-in pressure. Pipeline packing to secure pipeline pressure above wellhead pressure is important to avoid any backflow from the reservoir during start-up.

Fluid temperature

Joule Thomson (JT) effect is very large for CO_2 in gas phase condition. Consequently, will any large pressure drop where gas flashing occurs result in a very low temperature. However, the Aurora reservoir pressure is expected to be sufficient to secure single phase liquid at the wellhead. Consequently, will there be no low temperature problems due to JT cooling during normal operation of the system.

Depressurization of the pipeline system implying CO_2 going in to gas phase may however result in low temperatures. Consequently, should any depressurization be limited to a small flowrate allowing heat transfer from the ambient (i.e. slow depressurization).

Fluid velocities:

Pipeline fluid velocity has been calculated to maximum 2.7m/s with a flowrate of 5Mt/y.

3.4.3 Hydrate control philosophy

Hydrates in the transport system (pipeline and subsea)

Design basis states a maximum water content of 30ppm in the CO_2 stream. This entails that not free water is present in the pipeline or subsea system and consequently no hydrates will be formed in the transport system.

Hydrates at bottom hole

When the CO_2 comes down to the reservoir it will meet reservoir water resulting in higher HET compared to the CO_2 containing only 30PPM of water. The hydrate curve for CO_2 saturated with water will depend on the salt content of the water. Hydrate curves based on CO_2 saturated with water with and without salt is given in Figure 3-6. For the time being the salt content in Johansen is expected/predicted to be approximately 5 wt% NaCl[4]. Hydraflash shows that bottomhole hydrate curves with 5wt% salt in the water decreases the hydrate temperature by 3°C when compared with distilled water value of 10°C.

It has been concluded that impurities have no effect on the hydrate curves on both top side and bottomhole.

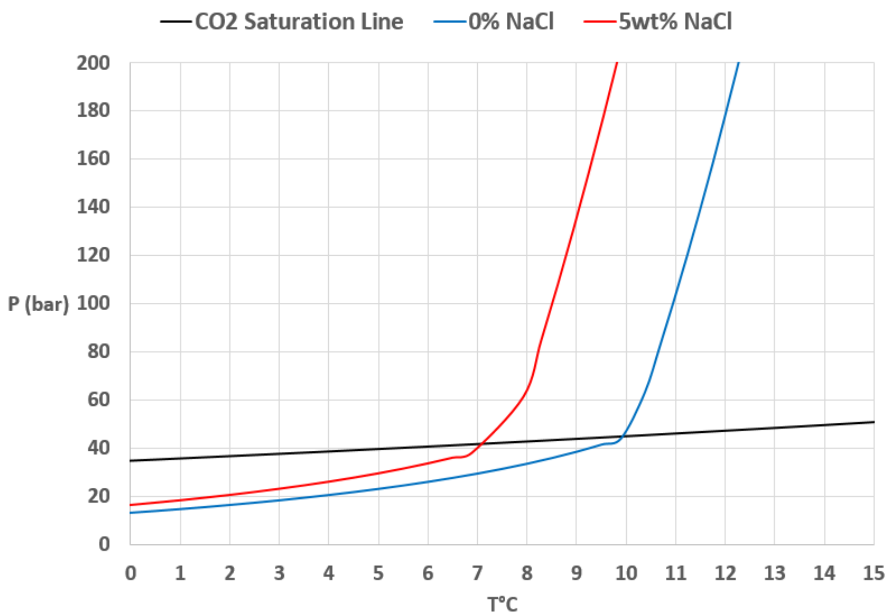


Figure 3-6 Hydrate curves at bottomhole (in saturated water) , Hydrate curve base on 5wt% NaCl in the formation water given by the red curve, and 0wt%NaCl in the formation water with the blue curve

Both steady state analysis and transient operations shows temperate above HET for all analysed cases. Based on these results, MEG injection will not be required during any shutdown or start-up cases.

[4] No formation water sample is available. The salinity is assumed to be comparable to waters of the region, until samples are acquired.

The only reason for having MEG for hydrate control will be as a measure if hydrates in the reservoir occurs. If the hydrate plug doesn't melt due to ambient condition, MEG will be required. This may be supplied with use of a vessel.

3.5 Metering philosophy

The metering philosophy for the concept is based on the project's understanding and working assumptions for regulatory and commercial requirements. Continuous dialogue with regulators is planned to ensure the design complies with the regulatory framework.

Metering is planned as follows:

- Volumes (or mass) will be measured at the capture site as the CO_2 is loaded onto the ship.
- Ship tank level measurements will be made to measure volumes offloaded at Naturgassparken.
    - Losses/discrepancies in transit can be calculated based on level measurements at loading and offloading.
- Online analysis of O_2, H_2O, H_2S, plus sampling of the offloaded CO_2, will be made at the inlet to Naturgassparken to protect the facilities and document composition of injected volumes.
- Vented volumes and fugitive emissions will be estimated or based on tank level measurements where applicable.
- A subsea venturi meter will be installed to measure the flow at the well. Subsequent wells will also be equipped with venturi meters to allow reservoir monitoring and management.

In addition to the planned metering, space for two additional metering stations have been allocated:

- Space allocated at the inlet of Naturgassparken facilities to install a "fiscal" metering system for 3rd party commercial volumes.
- Space allocated for metering at the outlet of Naturgassparken.

Requirement for these additional meters will be confirmed in the FEED phase. For both these meters, technology qualification will be required.

3.6 Subsurface

3.6.1 Introduction

The Northern Lights project commenced the evaluation of the Aurora area for CO_2 storage purposes in June 2018. A comprehensive study of CO_2 storage in the Johansen formation (Fm.) in the Aurora area was carried out by Gassnova between 2008 and 2012. This study was used as a starting point for the evaluation done by the Northern Lights project.

The study by Gassnova concluded that the Johansen Fm. in the investigated area can store large amounts of CO_2. However, as the studies were based on a conceptual model the study also concluded that a well should be drilled to confirm presence of a suitable reservoir (sand). So far, the presence of sand is based on seismic data and wells in the greater area, but it is not proven to be present within the Aurora exploitation licence.

The Northern Lights project introduced an intermediate milestone, the Aurora Validation Point (AVP), for a decision on whether the project would proceed with plans to drill a well in the licenced area for a confirmation of the geological concept. The subsurface part of this report has been updated with a summary of the evaluation leading up to AVP.

Northern Lights' evaluation is based on the CGG 17 M01 seismic survey which became available after the Gassnova study. The main difference between the Gassnova and Northern Lights studies is that the project has concluded the first well needs to be moved further north (shallower) to increase the likelihood of encountering a suitable sand for CO_2 injection. The updated subsurface concept is described in section 3.6.2.

3.6.2 Storage concept

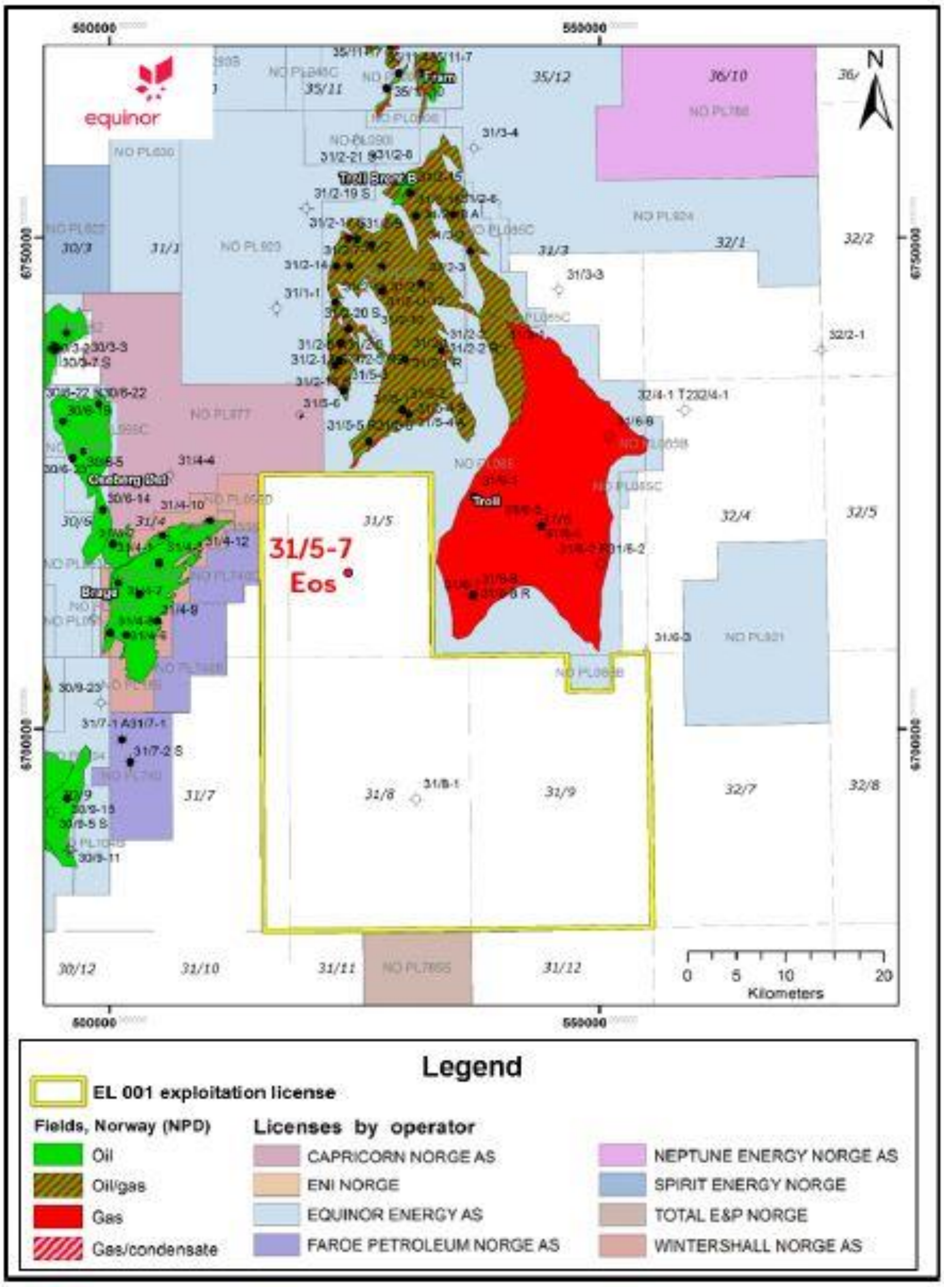


Figure 3-7 Aurora area with the location of confirmation well (Eos).

The concept is to inject and store CO_2 in the Johansen/Cook Fms. (storage unit) approximately 10km south of the northern licence boundary as shown in Figure 3-7. Driven by buoyancy, the CO_2 will migrate northwards over time and accumulate at an approximate depth of 2100m below seabed, below the Troll reservoirs. A north-south cross section through the Aurora and Troll area is shown in figure 3-8, illustrating the storage concept in more detail.

Above he storage unit, the Drake Fm. (shale) will act as the cap rock, and thus stopping the CO_2 from migrating out of the storage unit. In addition, the presence of the Troll hydrocarbon reservoirs shows that there are efficient barriers further above that would prevent the injected CO_2 from reaching the sea bed.

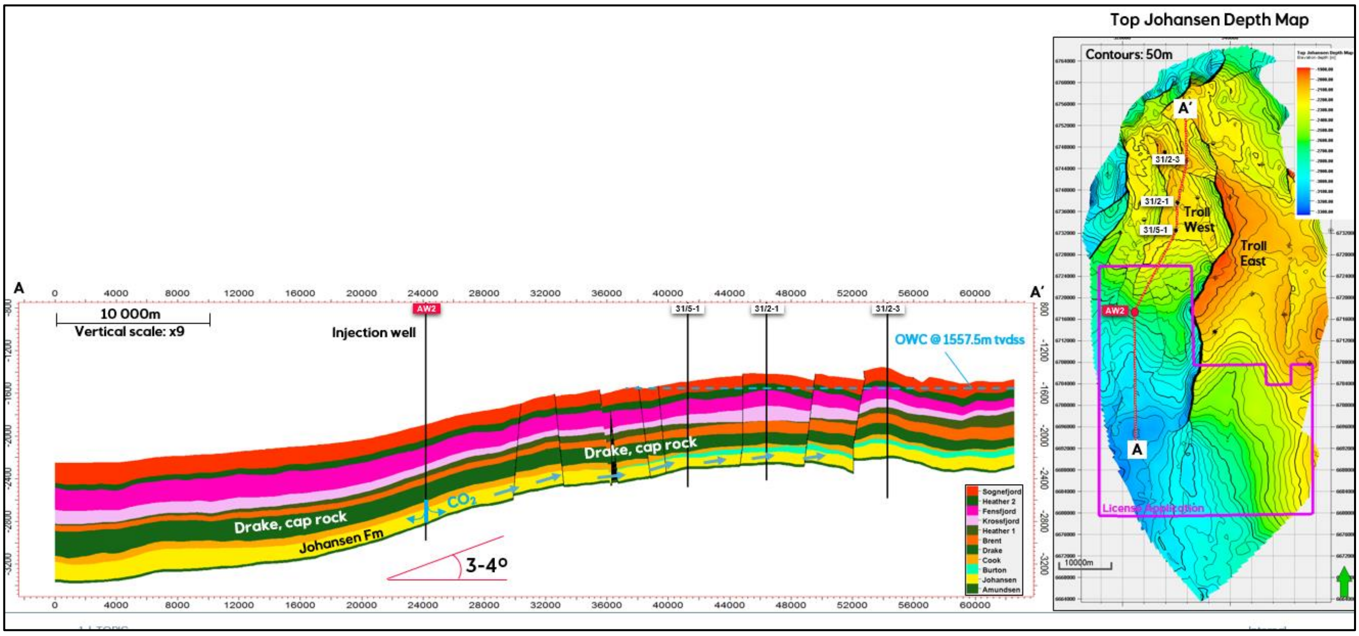


Figure 3-8. A north-south cross section through the Aurora and Troll area with a preliminary well location

3.6.3 *Scope of subsurface evaluation*

Prior to commencing a comprehensive subsurface evaluation, previous work was screened to identify any obvious obstacles that could compromise the project from moving forward. No project stoppers were identified, but the assessment revealed that several elements needs to be studied and solved to mature the subsurface to the required level prior to an investment decision.

To mitigate/reduce the main risk (reservoir sand presence), a confirmation well is required to confirm presence of a reservoir suitable for CO_2 storage. The objective of the subsurface studies up to AVP has been to confirm the feasibility of CO_2 storage in the area and improve the understanding of the risk picture given a desired outcome of the confirmation well.

The assessment up to the AVP milestone has been based on the geo/simulation model grid (the concept model) from Gassnova. The following work has been carried out by the Northern Lights subsurface team:

- Revision on relevant well data in the greater area and depth trends to establish depositional scenarios
- Verification of the geo-model grid based on the CGG17M01/CGG18M01 survey which was not available when Gassnova's concept model was made
- Evaluation of seismic response and amplitude distribution to guide depositional scenarios
- Interpretation of additional horizons for depth conversion
- Uncertainty study to investigate storage capacity robustness

- Leakage risk assessment using bow-tie methodology
- Evaluation of seismic response on CO_2 to verify that the CO_2 plume can be monitored (monitorability)
- Evaluation of well completion and required injectivity to meet requirements of a minimum injection of 0.8 Mt/y/well
- Recommendation of location of the confirmation well and probability of success (POS) to meet a set of criteria for the well.

3.6.4 Summary of results

The evaluation of the Aurora area has concluded on an optimum well location. The objective of the confirmation well is to confirm:

- The presence of a sand with sufficient permeability for injection of CO_2, sufficient porosity for monitorability, and sufficient connectivity to provide enough storage capacity.
- The presence of a seal (the Drake fm.).
- That there is no hydraulic communication with the Troll reservoirs.

Flow properties and connectivity of the sands in the Dunlin Gp. are major uncertainties and work is ongoing to design a well test to reduce these uncertainties by flowing the well.

The evaluation of storage capacity concluded that given confirmation of the expected reservoir properties by the confirmation well, CO_2 can be injected in the Cook and Johansen Fms. of the Dunlin Gp. The storage capacity will be further quantified based on the well results, with an agreed methodology for categorising CO_2 storage volumes.

The evaluation shows a possibility of the CO_2 plume migrating across the license boundary in the Dunlin Gp., northwards into the Troll license, prior to the anticipated end of field life for the Troll field (2054). This migration will be within the Dunlin Gp., stratigraphically segregated from the Troll reservoirs, but still represents a risk that will be further assessed by the project.

Pressure data indicates that there is a hydraulic seal between the Dunlin Gp. and the Viking Gp., which will prevent the CO_2 from migrating to the Troll reservoirs. This will be verified by pressure data in the planned confirmation well. It will also be evaluated in the next phase whether additional pressure data from the Dunlin Gp. below Troll is warranted.

The leakage risk assessment indicates that the risks of fault reactivation and along fault flow of CO_2 out of the Dunlin Gp. to shallower levels are low. A juxtaposition of Dunlin Gp. to the Brent and lower Viking Gps. along the Svartalv fault is observed. Current assessment is that this fault is sealing. Further work will focus on quantifying the impact of potential migration across the fault and a mitigation strategy should this be observed.

The monitoring assessment indicates that the CO_2 plume can be monitored down to a thickness of approximately five meters, depending on reservoir properties. In the next phase, a monitoring and response plan will be developed. In the operational phase, monitoring must be combined with reservoir simulation, thus high quality, reliable subsurface models are required.

3.7 Drilling & Well

A concept report for drilling and well is provided as a separate report to Gassnova. This section gives a summary of the main features of the well concept.

With a water depth around 300m, Aurora well(s) will be drilled with a semi-submersible rig. The design for the confirmation well will comprise a 30" conductor, 20" surface casing, 13 5/8" intermediate casing and 9 5/8" casing and is planned for execution in Q4 2019. The verification well will be designed as a keeper and temporarily plugged and abandoned. In 2023 this well will be re-entered to drill a sidetrack, install a 7" liner to the base of the Cook Fm and run completion.

The base case is a vertical early confirmation well with the injector sidetrack kicked off beneath the 9 5/8" casing shoe from the P&A cement plugs and reaching an inclination of approximately 10 degrees through the Johansen Fm.

Deviation from standard design is limited to the inclusion of corrosion resistant alloys in the 7" injection liner, 4 ½" x 5 ½" injection tubing and 4 ½" screens.

The well will be completed with material requirements for injection of CO_2. Standardized tubing and completion equipment will be used as far as possible to reduce cost.

Lower completion with standalone screens (SAS) is the base case. Depending of the injection reservoir chosen, different tubing sizes can be select in the upper completion. For cost and simulation work a 5 ½" tubing is chosen as preliminary base case.

To minimize intervention time and cost in the post-completion phase, an intervention less solution should be planned for. The well will be designed for possible intervention with Coiled Tubing, wireline and slick line.

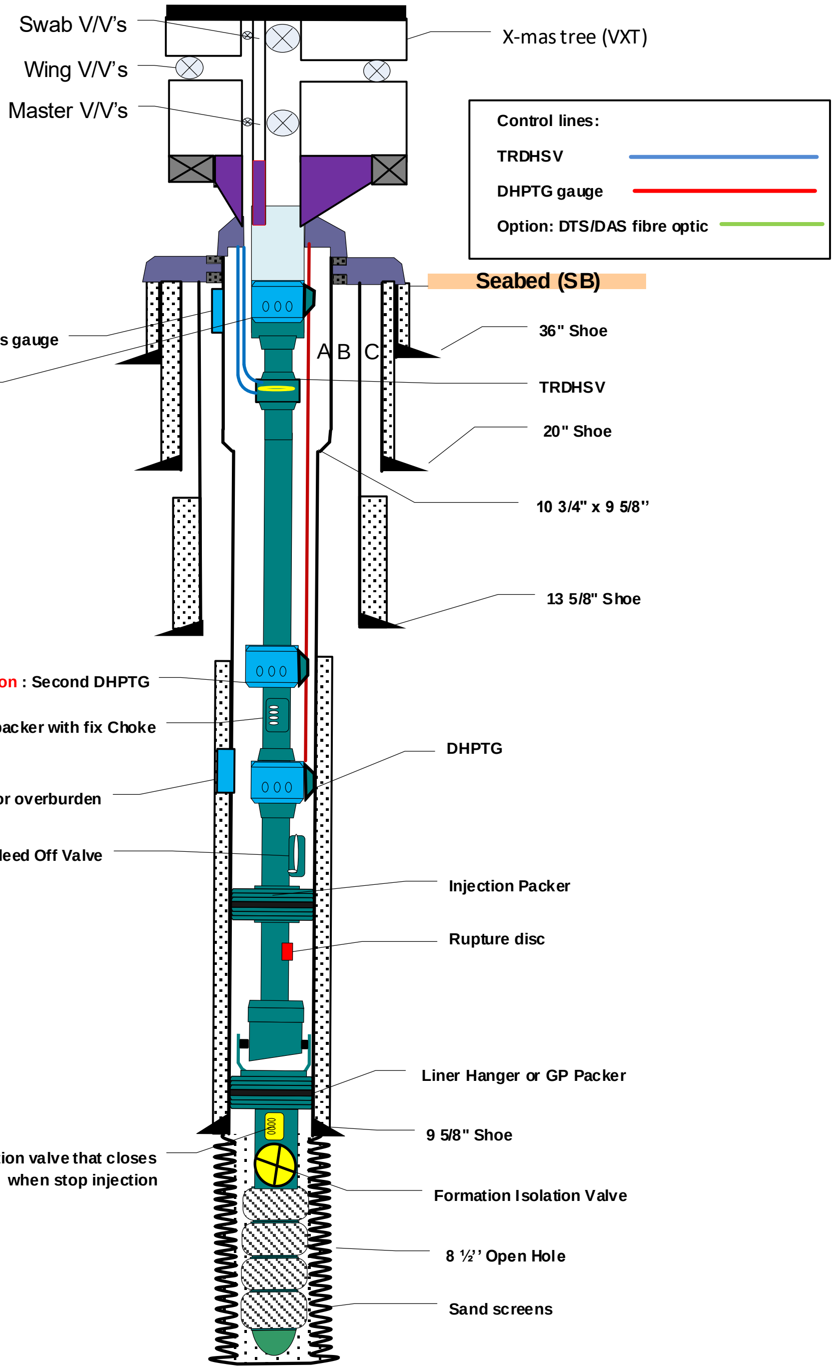


Figure 3-8 Well schematic

3.8 Facilities

3.8.1 Subsea facilities

The purpose of this section is to describe the concept selected during the concept study phase for the Subsea Injection Facilities.

3.8.1.1 Summary and conclusion

The main concept for the Subsea Facilities for Northern Lights is based on a single well satellite phase 1 injection and permanent storage of liquid CO_2. The Subsea Facilities for Phase 1 is described in detail in this section. Some assumptions for the phase 2 of the development were selected for the concept selection process. See section 3.8.1.6.

In addition, some Subsea Facilities pre-investments are also included in the recommendation, to allow for the phased development and minimise costs in the future, for example:

- Tie-in hub for future flowline connection (located on the PLEM and used for pigging for phase 1)
- Tie-in possibility for an infield umbilical for future wells
- DC/FO combined to a fluid umbilical, instead of conventional umbilical, to increase flexibility for future developments

Competitive tendering for the engineering, fabrication and delivery of a subsea structure and the wellhead system to allow for drilling of a confirmation well in Q4 2019 has been initiated. The objectives of the confirmation well are both to validate the well target defined by subsurface and to be used as a “keeper” well for injection from DG4.

Other selections evaluated prior to concept select are:

- Subsea structure
  Several alternatives have been studied and evaluated. Based on flexibility, risk and cost evaluation, a single satellite structure is selected for Northern Lights.

Table 3-6 Subsea structure main characteristics

Structure	Dimension (m)	Weight (Te)
Foundation structure incl. hatch	18 x 11.8 x 11.1 (W x L x H)	Min.103
Suction anchor diameter/ height/ thickness	Ø 4.0/ 4.0-12.0/ 16-25mm	
Foundation structure excl. hatch	18 x 11.8 x 8.6 (W x L x H)	Min. 89

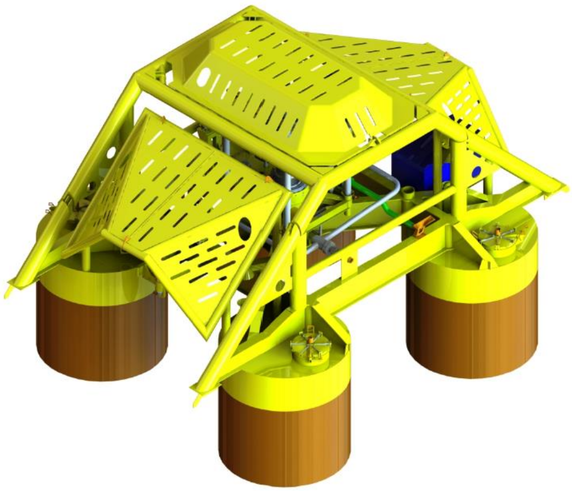


Figure 3-9 Northern Lights pilot satellite structure with suction anchors and trawl protection

- Subsea control station location
  Based on feasibility and cost benefit evaluation, Fedje island is preferred to the initially planned location at Naturgassparken, where the main onshore facilities for the project is being established. An additional opportunity for an offshore host with Oseberg field center is being evaluated but is kept as opportunity post-concept phase, due to time and resources constraints.

- X-mas Tree
  A vertical Christmas tree based on the standard Equinor solution is selected for Northern Lights subsea facilities.

- Umbilical system solution
  A new umbilical system is required to be installed to control and monitor the subsea facilities on Aurora. Both an integrated umbilical solution and a combination of a DC/FO and a fluid umbilical have been evaluated. Based on technical reliability and feasibility, flexibility and cost evaluation, a combination of DC/FO and fluid umbilical is selected as base case for the umbilical system for Northern Lights.

- System design
  Due to the phased development of Northern Light, assumptions have been established for the total number of future wells and the maximum step-out from the phase 1 well location. Considering these assumptions as well as the electrical, signal and hydraulic analyses, a system design, taking into account both phase 1 and 2, is established.

- Umbilical routing
  Several routes have been studied both to Smeaheia and to Johansen respectively from Naturgassparken and Fedje. The Concept phase base case is based on the initial well location 31/8 1X2 specified on Johansen. The routes to the pivot points towards the two well target locations on Aurora will form the basis for the phase 1 of the FEED study from Saipem, until the Aurora Validation Point date. The final approach to the well target will be studied in the phase 2 of the FEED study.

- Flow assurance
  The main elements from the flow assurance work impacting the subsea facilities scope have been summarised in Section 3.4 of this document.

- Battery limits and layout
  The subsea satellite layout and battery limits between pipeline and the subsea facilities are illustrated below.

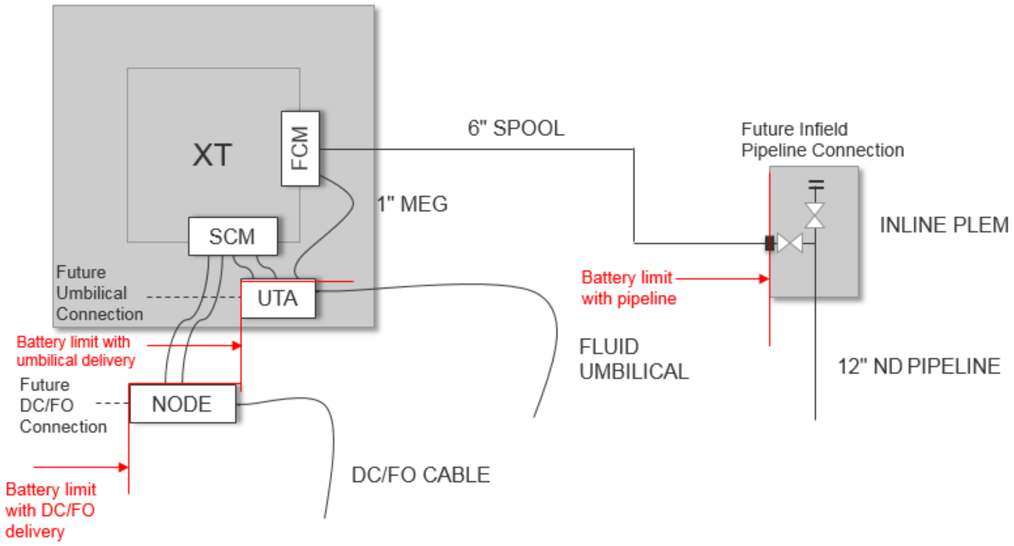


Figure 3-10 Battery limits between the pipeline and the subsea facilities

3.8.1.2 Concept selection

The following criteria were used throughout the concept selection process to ensure the optimal solution is selected:

1. Technical: Injection in liquid phase, injection capacity, reliability, availability
2. Cost optimisation for both CAPEX and OPEX
3. Flexibility: for present and future expansion and operations, uncertainty related to well locations, optimisation of business case to reduce OPEX

3.8.1.3 Subsea system & field layout

<u>Subsea layout phase 1</u>

The Northern Lights Phase 1 subsea development is based on a single well, single header, CO_2 injection satellite structure, located above the Johansen formation South-West of the Troll field and East of the Oseberg field. The preliminary location of the well is approximately 85km from shore.

A subsea concept is selected considering the low number of planned wells. Various subsea well configurations have been evaluated – single slot satellite wells, 2-well templates and 4-well templates. A satellite well configuration has been selected, enabling far step-out and future wells according to reservoir needs. Additionally, a satellite well entails a low initial investment.

Several locations for the control station for the subsea system have been evaluated. A land-based control station at Fedje island has been selected.
The island of Fedje, some 20km north of Naturgassparken, is the preferred onshore location for the control station. Co-location with the Onshore Facilities at Naturgassparken, would benefit the maintenance of the control station, however it adds more than 20km to the length of the umbilical system and a challenging landfall solution.
The first well meets the design injection capacity for phase 1 of 1.5Mt/y CO_2.

<u>Subsea layout phase 2</u>
The subsea system is prepared for daisy chaining to four additional wells. Both the fluid umbilical and the DC/FO cable connect to the first well, as well as to future umbilicals and cables, through short ROV made-up jumpers. The end manifold (PLEM) of the main 12 ¾" pipeline has a connection point for a phase 2 infield pipeline, which in turn will be connected to each of the future wells via rigid spools.

<u>Control system and subsea control station concept</u>
The Subsea Injection Control System will control all valves and chokes on the X-mas tree and flow control module and read all instruments. It will have a flexible design allowing for future expansion or future added functionality.
The step-out length is approximately 85km to the landfall at Fedje. Due to the long step-out, fibre communication is applied for primary and secondary communication. No copper-based communication is considered.
A full all-electric solution has been considered but since this technology is not yet at TRL 4 and since there is some uncertainty for when it will be fully qualified, it has not been considered further. The basis for the project is therefore an electro-hydraulic system with DC power supply and fibre optical signal transfer. It may however be an opportunity for later phases of the project, assuming successful technology qualification to expand using all-electric technology.

An open water-based hydraulic fluid will be applied according to the latest standards. No return flow line is then required. The control system will apply a pressure intensifier to provide HP hydraulics of up to 690bar for the downhole safety valve. This eliminates the need for HP lines in the umbilical. This type of systems has been delivered for many projects and has proven to be reliable.
The subsea injection control system should be based on Equinor's standard equipment if possible. This will imply benefits when it comes to costs of engineering, tools, spares and maintenance, as well as delivery lead times for main subsea modules.

3.8.1.4 Subsea structure and manifold system

Various single well satellite structures and multi-well structures have been considered for use on Northern Lights.
The single well satellite structure, with integrated protection structure and structural support for the wellhead, was selected due to its capacity to support the wellhead/VXT/BOP and its low investment cost. It is based on the standard portfolio for NCS subsea developments. Equinor's frame agreement NCS2017+ equipment is used where applicable. The satellite structure will need to support a vertical X-mas tree (VXT), the wellhead system and the separately retrievable CO_2 injection header flowbase. The latter accommodates the termination of the 6" pipeline spool and the interface to the supply fluid umbilical.

The system shall be overtrawlable, which means the satellite will have hatches covering the VXT, flowbase and umbilical system interface. A separately retrievable flowbase results in a simpler satellite structure with short delivery time, as opposed to a header/manifold fully integrated in the satellite structure. This enables installation of the structure in time for the confirmation well to be drilled in Q4 2019. The flowbase enables the tie-in of the rigid CO_2 injection spool, service and control lines to the vertical connection (VMX) on the VXT. CO_2, MEG and hydraulic lines will go through the VMX hub, while electrical lines will go directly from the seabed located DC/FO node to the control module on the VXT.
The tie-in system for the injection spool is of the type HCS (Horizontal Connection System), which is a standard, proven technology.

The umbilical interface will be an Umbilical Termination Assembly (UTA), locked onto the structure and with connection points for flying leads with wet mate connectors. All connections will be done by ROV. Wellhead load relief shall be accommodated for, in case the BOP used during the drilling campaign is heavy, or the number of BOP days is high.

The flowbase will include the following equipment:

- 6" production branch piping
- 1 off 12" HCS flowline hubs
- 1 off 5 1/8" ROV gate valve
- 1 off 12" multibore hub
- 1 off UTA support
- Small bore piping/ valve arrangement
- Electrical flying leads cables from umbilical

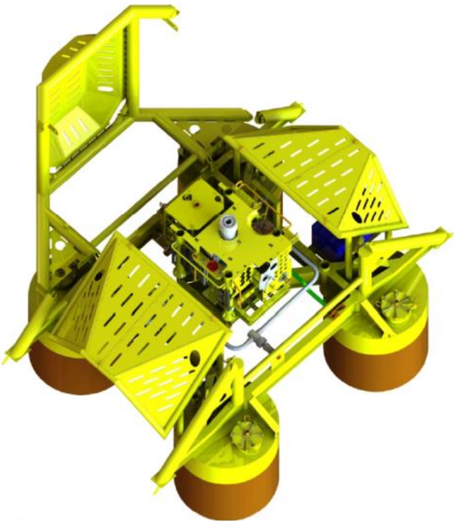


Figure 3-11 Northern Lights pilot satellite structure with vertical X-mas tree installed (main hatch open to demonstrate ROV access)

3.8.1.5 Subsea X-mas trees system & work over system

X-mas Tree System

The standard NCS 2017+ 7" x 5" Vertical X-mas Tree (VXT) is selected for Northern Lights. The VXT is configured as a concentric production bore design with Tubing Hanger (TH) installed conventionally in the Wellhead (WH) below the VXT. Production & annulus stabs, and electrical / hydraulic stingers provide wet-mate communication between the bottom face of the VXT and the top face of the TH.

Tie-in from the VXT to the flowbase is via a Vertical Manifold to XT connection (VMX) system actuated via ROV torque tool. To eliminate snagging of manifold hub in VXT connector, the hub is stroked downward / away from the VXT connector prior to running or pulling the VXT.

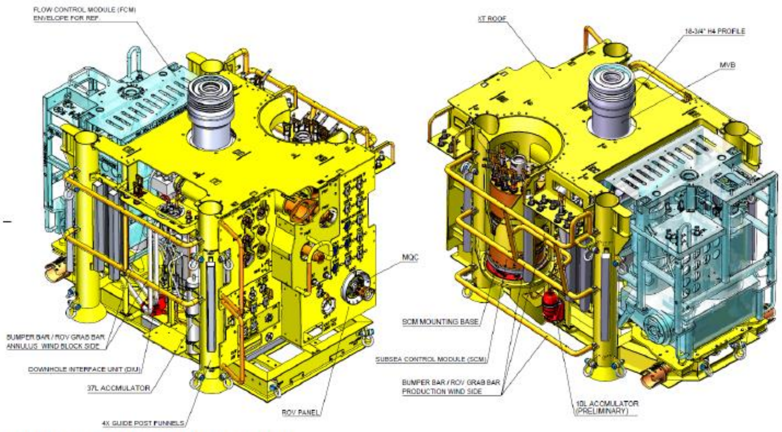


Fig. 4.33 Standard NCS 2017+ 7" x 5" VXT

Figure 3-12 AKSO Vertical Xmas Tree

Flow Control Module (FCM)

The flow control module connects the VXT to the pipeline spool and to hydraulic control fluid / MEG conduits in the fluid umbilical. It contains vulnerable components (for example choke valves) with a higher repair frequency and are separately retrievable from the VXT and the flowbase.

The Injection FCM equipment configuration for Northern Lights is described below:

- Injection choke valve (ICV), electrically actuated
- Single Phase Flow Meter (SPFM)
- Dual PTT upstream the ICV
- Dual PTT upstream the SPFM
- Dual 1" chemical injection valve block, 1 electric + 1 hydraulic actuator
- MEG injection point between SPFM and ICV
- CO_2 Leak Detector (LD)
- Chemical injection throttle valve (CITV) for MEG
- Check valve for chemical injection point for MEG
- Hot stab for back seal test

3.8.1.6 Control system and land based subsea control station

General

The electro-hydraulic control system will have redundant power and provide redundant operation of valves and instrumentation.
A standardised communication protocol on a TCP/ IP network will be applied between the satellite Subsea Control Module (SCM) and topside/ onshore equipment. The network will consist of a combination of optical/ electrical media converters and network routing switches.
The control system shall be based on field proven technology and according to the latest version of the applicable industry standard API 17F with additional Equinor requirements as expressed in TR1233.

Field wide assumptions, conventional power distribution

The following requirements apply for phase 1 and phase 2 field-wide analysis:

- Phase 1 is one injection well.
- The subsea control system shall be dimensioned for phase 1 and phase 2.
- HPU shall have capacity to support at least five wells.
- Power and Communication (SPCU) shall have capacity to support at least five wells. Phase 1 comprises a combination of a fluid umbilical and a DC/FO cable.
- Phase 2 wells shall be operated via the phase 1 umbilical system on a step-out from the phase 1 well of maximum 20km, i.e. in total 60 km from the offshore host and 110 km from the onshore host.
- One fibre cable and one quad will be reserved for future use by Underwater Intervention Drone (UID).
- Controls power by DC/FO (base case).

Controls power

With a land-based control station case, the umbilical length will be 85km. At this distance, a DC/FO solution is the preferred solution. The power and communication will be provided with a DC/FO solution and one subsea node per manifold.

Instrumentation

- General
  The instrumentation includes pressure and temperature transmitters on the X-mas tree and the FCM. There will be a Venturi liquid flow meter for measuring the flowrate of CO_2. The control module will have an interface for downhole instruments. This may be pressure and temperature, or fibre optic-based instruments.
  In addition, there is a comprehensive amount of housekeeping and monitoring instruments for the SCM functionality. Table 3-7 summarises the minimum monitoring requirements for the CO_2 injection control system on the X-mas tree or FCM.

Table 3-7 Subsea control system monitoring requirements

	Description of Equipment	Location	Range
1	CO_2 injection flow meter	Flow Control Module (ref.ch.3.7)	– TBA m3/h
2	Pressure transmitter/ temperature transmitter (high accuracy)	VXT and FCM (ref.ch.3.7)	Pressure range: 0 – 690 bar Temperature range: -18 ºC to +121 ºC
3	Choke position indicators	FCM (ref.ch.3.7)	0 – 100%
4	Leakage detector	VXT or FCM	CO_2 detection
5	Umbilical monitoring	SPCU	10 Gohm Hi Range

- Leak detection:
  In addition to traditional leakage detection measures for subsea injection systems (i.e. pressure readings from the X-mas tree and FCM), installation of a leak detector is being considered. The leak detector shall detect and identify the location of leakage of CO_2 on all equipment located on the X-mas tree, FCM and flowbase/CO_2 header. The instrument shall perform trending and transfer selected data to SAS including alarms for leak detection. Alarms for leak detection shall indicate location of the leakage. Leak detection can be by means of CO_2 sniffer or acoustic detectors. Suitability and qualification status for use with CO_2 injection wells must be assessed.
- Flow measurement
  The injection flow rate is foreseen measured subsea using a Venturi liquid flow meter, which is based on differential pressure measurement. If such a Single-Phase Flow Meter (SPFM) is found feasible in a CO_2 application and can be marinized for subsea use, it will be located in the FCM. Suitability and qualification status for use with CO_2 injection wells must be assessed.

3.8.1.7 Control Station equipment

The topside equipment for the Subsea Control Station will include the following:

- Subsea Control Unit (SCU)
- Subsea Gateway
- Hydraulic Power Unit (HPU)
- Chemical injection Unit (CIU) for Mono Ethylene Glycol (MEG)

A traditional controls power system will, in addition, require Electrical Power Unit (EPU) while a DC/FO based system will require Power Feed Equipment (PFE).

Subsea Control Unit (SCU)

The Subsea Control Unit (SCU) will provide a dual redundant interface and the control of the subsea control system equipment to the main control room (SAS). The SCU comprises a number of logic nodes linked to the dual SAS network, controlled via an Operator Work Station (OWS) located in the main control room. The SCU cabinet solution will be a single cabinet.

Power Feed Equipment for DC/FO (PFE)

The Power Feed Equipment (PFE) for DC/FO requires two cabinets. Both cabinets can be installed in an unlocked equipment room, but HVAC requirements needs to be considered as heat dissipation is significant. Figure 3-13 shows the PFE racks.

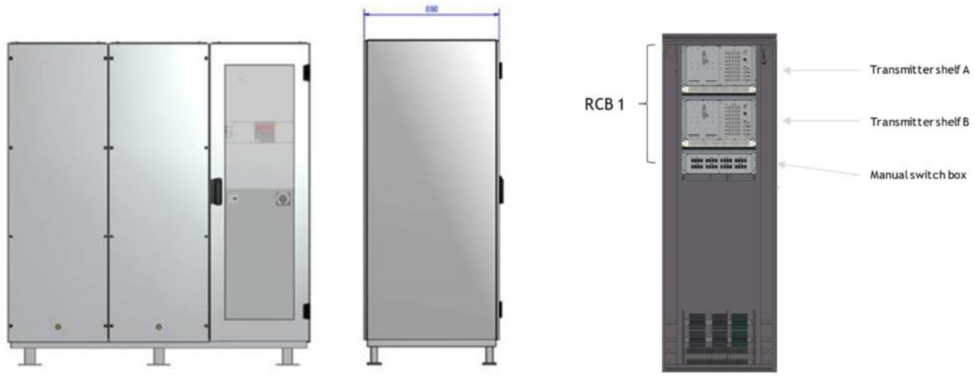


Figure 3-13 Typical Power Feed Equipment for DCFO

Subsea Gateway

The Subsea Gateway provides the communication interface between the SCU and the subsea injection system. The subsea gateway contains Ethernet switches and optical fibre connection panels which receive the PCS fibres from the DC/FO cable junction box and provide a FO Ethernet controls interface to the SCU. The subsea gateway provides a dual-redundant (A and B) signal transfer system. Figure 3-14 shows an EPU and subsea gateway cabinet.

Figure 3-14: AKSO topside cabinet (EPU and Subsea Gateway)

<u>HPU</u>

The Hydraulic Power Unit (HPU) will supply hydraulic control fluid for remote operation of the various valves on the subsea X-mas tree and FCM. It will be controlled from the main control room SAS system. It shall have capacity to serve minimum five wells. Figure 3-15 shows a typical HPU.

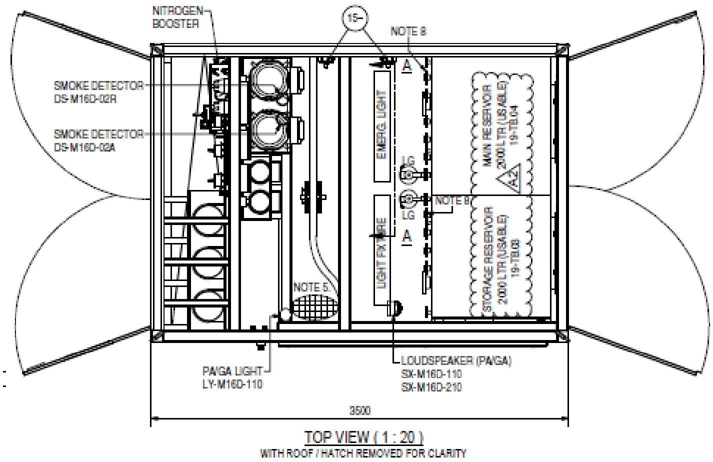


Figure 3-15 HPU (example)

<u>CIU</u>

The Chemical Injection Unit (CIU) will be used for providing MEG or methanol for well operations and barrier testing. The pump shall be able to deliver MEG at 300bar with a flow rate of 10 m^3/h. The assumed fluid is MEG/water with a mixture ratio of 80/20 %. Storage mobile tanks of 6m^3 will be required.

3.8.1.8 Umbilical system solution and routing

<u>Umbilical System concept</u>

Two umbilical solutions may be used, depending on the distance from the injection well locations to the tie-in point for the control station.

Solution 1: A conventional electro-hydraulic umbilical with fibre optic communication cables.

Solution 2: A fluid umbilical plus a DC/FO cable for power supply and communication.

Figure 3-16 and Figure 3-17 below illustrate each solution at the subsea structure (well locations).

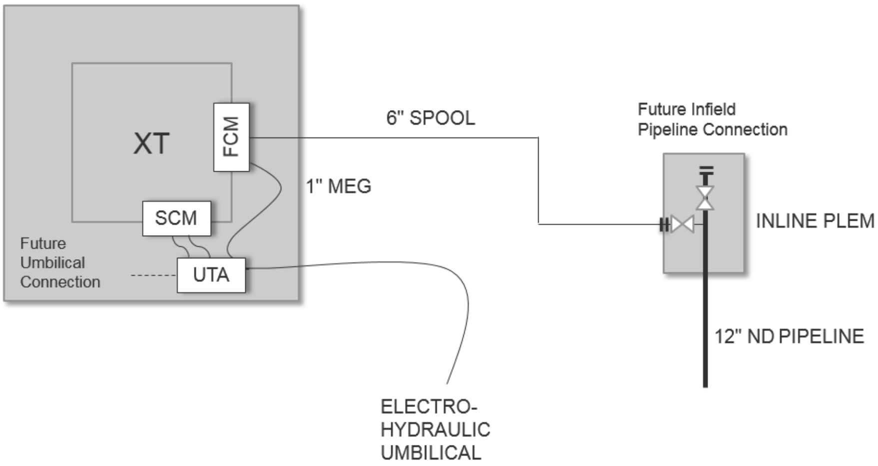


Figure 3-16 Umbilical system solution 1

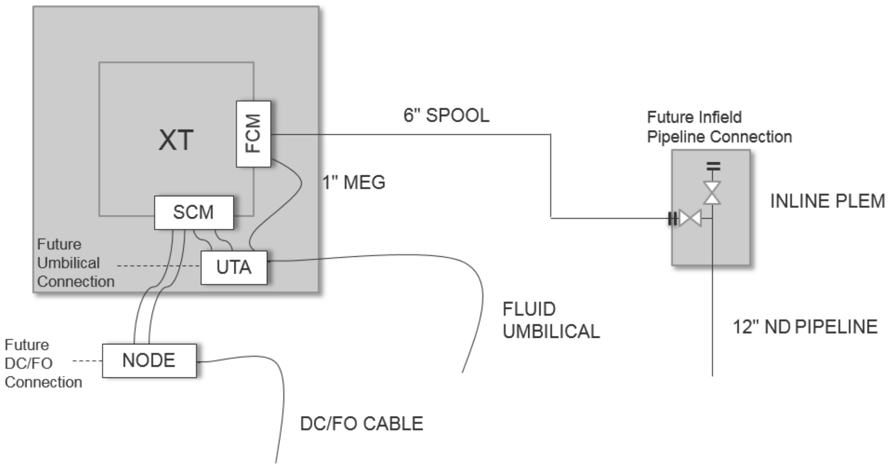


Figure 3-17 Umbilical system solution 2 (selected)

The umbilical system concept is to tie-in to a landfall at Fedje island (approximately 85 km from the offshore well location).

The umbilical system solution selection criteria and recommendation are described below:

1. Technical: no distance and power capacity limitations
2. Cost: Optimised cost from both short and long distances
3. Flexibility: Uncertainties related to well locations (distance), future expansions (wells and structures) and tie-in point. Solution also compatible with future technologies, such as All-electric subsea systems and Underwater Intervention Drones (UID), without further pre-investments in cables for power supply and communication. Flexibility for optimisation of business case to reduce OPEX

Based on an evaluation of these criteria, the two alternatives have been examined, weighed and concluded upon: it is recommended to select a fluid umbilical plus a DC/FO cable for power supply and communication.

Figure 3-18 illustrates the selected umbilical system concept.

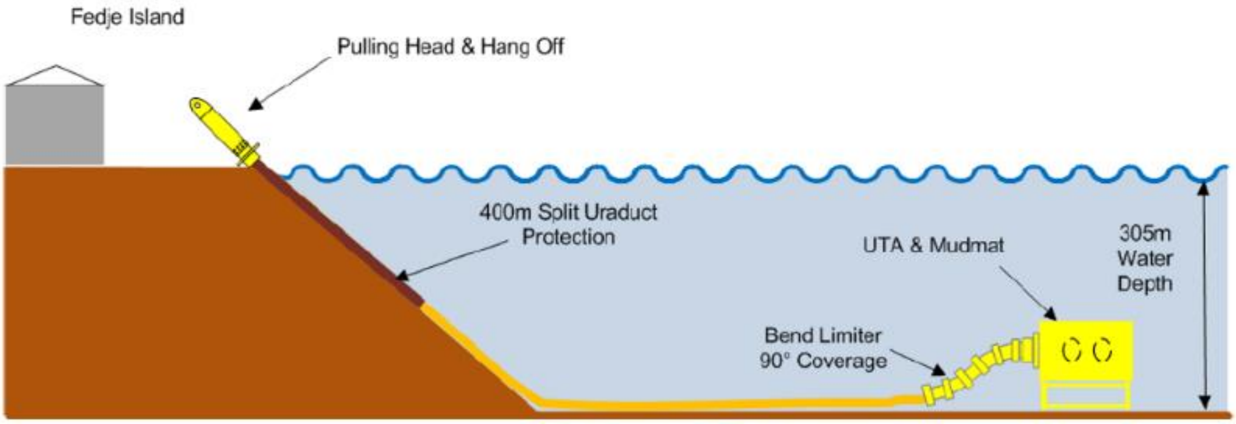
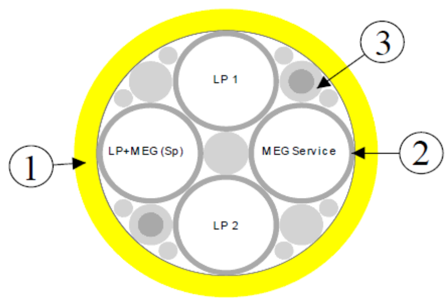


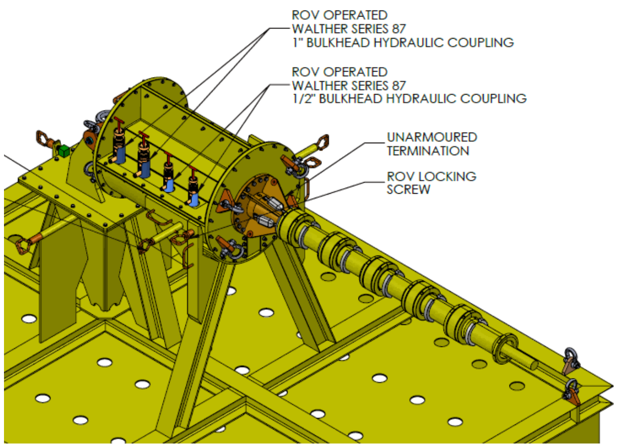
Figure 3-18 Umbilical system concept

Umbilical System description: Fluid umbilical and DC/FO cable for power supply and communication

Figure 3-19 below illustrates a fluid umbilical and DC/FO cable. This solution is currently being implemented in an Equinor project. The main differences between the conventional umbilical system and the DC/FO system are that the DC/FO system provides direct current (DC) as opposed to the alternating current (AC) provided by the conventional AC umbilical system. The DC/FO technology is a solution involving electrical conductors and optical fibers in the same cable. Hydraulic and chemical fluids must be provided by separate cables.



POS	QTY	Description	ID (mm)	WT (mm)	OD (mm)
1	1	Sheath	68.95	6.00	80.95
2	4	SD Tube 1" ID x 345 bar	25.40	1.42	28.24
3	2	Sheathed 7mm Galv Steel Wire	7.00	2.25	11.50



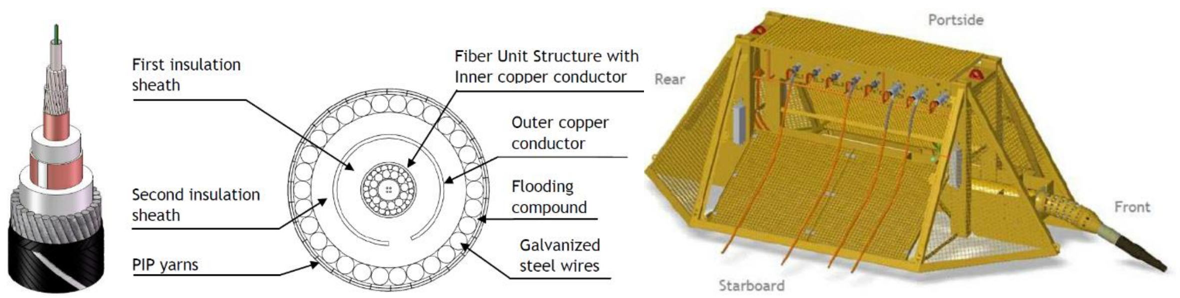


Figure 3-19 Umbilical solution 2: combination of fluid umbilical and DC/FO with subsea terminations (illustration)

Umbilical and DC/FO routing

Several alternatives have been studied, both for Smeaheia and Johansen formations. Only the solutions for the Johansen formation (Aurora) will be described in this report as shown on the figure below.

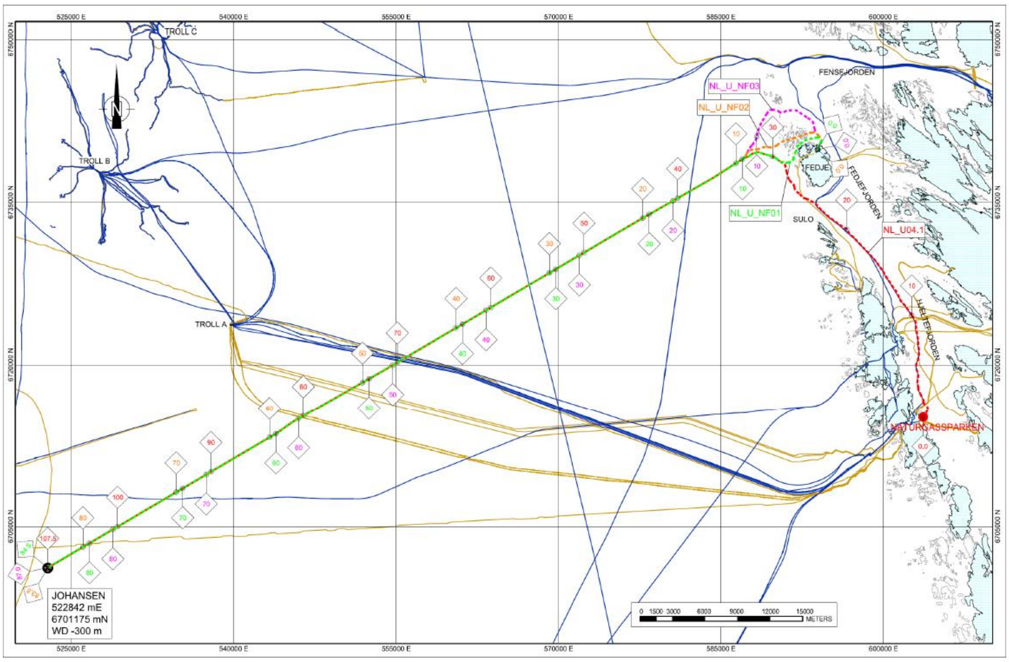


Figure 3-20 Umbilical (fluid umbilical) and DC/FO route options from Naturgassparken and Fedje assessed in pre-FEED

Both the umbilical and the DC/FO are anticipated to be installed alongside each other, although in two different installation campaigns, from two different vessels, on the seabed, with a minimum separation. The separation between the two lines depends on the seabed configuration and potential obstacles/ infrastructures present in the area. The umbilical and the DC/FO form part of the umbilical system.

1. Umbilical routes from Fedje

Three route options have been studied in the second phase of the pre-FEED study: NL_U_NF01, NL_U_NF02 and NL_U_NF03.

The main features of these routes are summarised below:

- The length of the umbilical running on these routes is 84470m, 83770m and 86990m for the various umbilical route options, respectively.
- The proposed centreline of the routes has been defined considering the presence of any potential restriction for umbilical installation (i.e. sensitive area, wreck, buffer zones, etc). In the area in the North of Fedje, it is noted that the umbilical routing is affected by the presence of fish farms. Particularly, the selected umbilical route runs very close to or across the fish farms anchor lines as per their position. Furthermore, the offshore area close to Johansen is affected by the risk of potential umbilical interference with active bottom fishing gears.
- The shore approach has not been studied in detail as an offshore survey with sea bottom profiler is due to be performed in October 2018, both for the zone South of Fedje and along the approach to Fedje and the Rognsvågen. The detailed routing in these zones will be studied in detail during the FEED phase when the detailed data from the shore approach morphology will be available.

- The crossings of existing facilities (pipelines/cables) have been examined. Subsea Rock Installations (SRI) have been designed accordingly to guarantee the requested minimum separation from the existing crossed facilities.

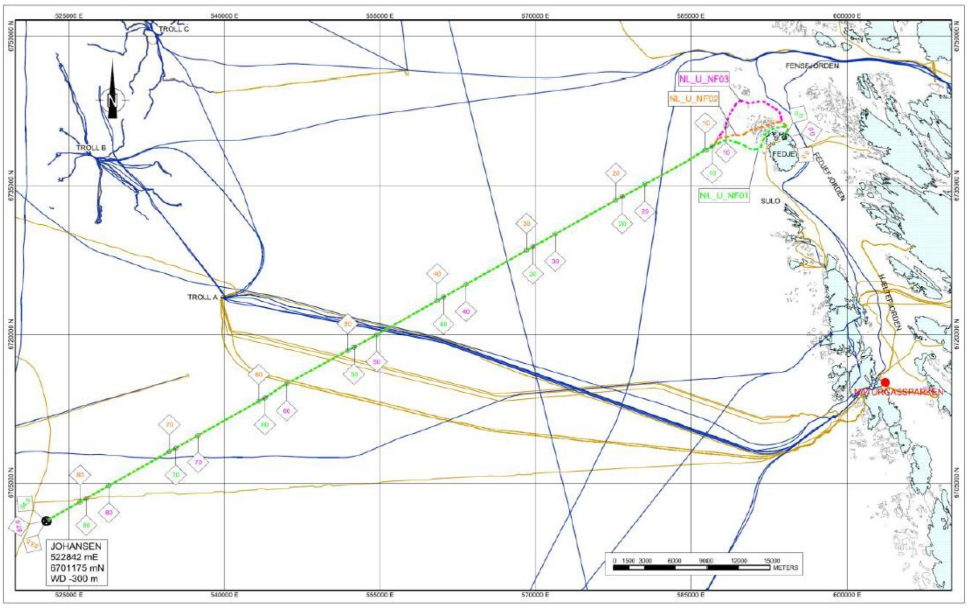


Figure 3-21 Umbilical option routes from Fedje

2. DC/FO routes from Fedje

The main features of the designed DC/FO selected routes (NL_PC_NF01) are summarised below:

- The length of the DC/FO is 84505m for route options NL_PC_NF01.
- The same constraints (sensitive area, wreck, buffer zones, fish farms, etc.) for routing identified for the umbilical are applicable to the DC/FO.
- The shore approach has not been studied in detail yet and as for the umbilical, will be detailed during the FEED phase.
- The crossings of existing facilities (pipelines/cables) have been reviewed. SRI's have been designed accordingly to guarantee the requested minimum separation from the existing crossed facilities.

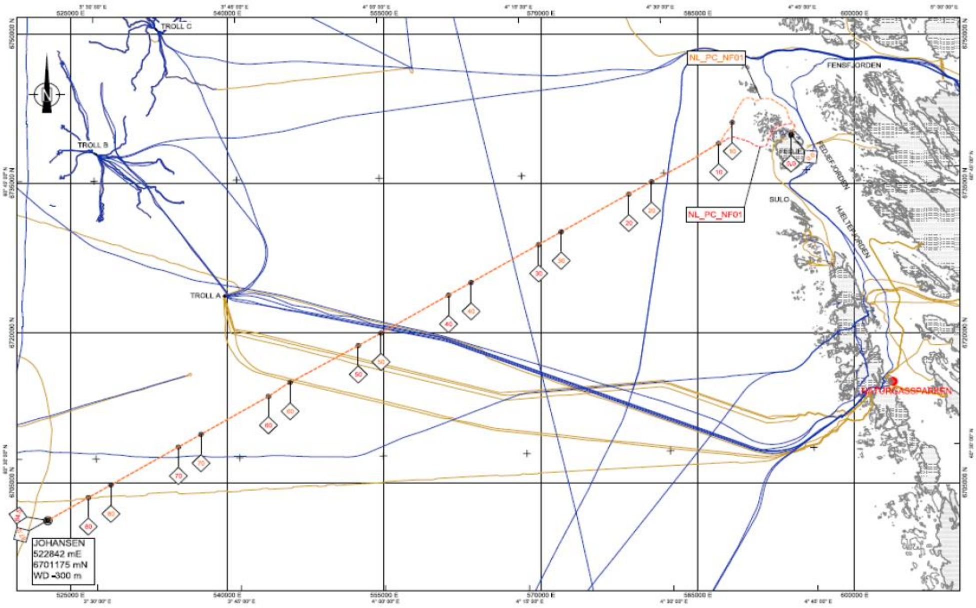


Figure 3-22 DC/FO option routes from Fedje

Table 3-8 summarises the qualitative assessment performed to establish the SRI's for the umbilical and DC/FOs routes examined in the pre-FEED study.

Table 3-8 Umbilical and DC/FO assessment for the routes options from Fedje

UMBILICAL/POWER CABLE ROUTE OPTION from FEDJE	Length (m)	Crossings (#/m[1])	Post-Trenching (m)	Fish Farms	On-Bottom Roughness (#/m[1])	UnStable Curves (no.)	Installation Constraints	On-Bottom Stability_ NOT STABLE Section Length (m)
NL_U_NF01	84469	15 / 5495	37200	Y	0 / 0	3	N	8590
NL_PC_NF01	84504	15 / 5495	37200	Y	0 / 0	3	N	6000
NL_U_NF03	86988	15 / 5495	37200	N	0 / 0	0	N	8860
NL_PC_NF03	87012	15 / 5495	37200	N	0 / 0	0	N	7000

stands for number of SRI
1) The design of the SRI suitable for OBS is postponed to the next project phase

3. Routes North of Fedje

The following main conclusions are drawn for the route options studied in the North of Fedje:

- Three corridors and two concepts for umbilical routing were available at the beginning of this study.
- Route option NL_U_NF01 is affected by some challenges associated to the proximity to a fish farm, umbilical route curve and on-bottom stability. These challenges are not deemed as severe as to be considered show

stoppers for the route feasibility. Route NL_U_NF03 is a feasible alternative route to NL_U_NF01. Based on the cost estimate, the route NL_U_NF01 is concluded to be the preferred route option.

- Both route options NL_PC_NF01 and NL_PC_NF03 are feasible for the DC/FO. Route NL_U_NF02 was discarded due to evident installation unfeasibility.

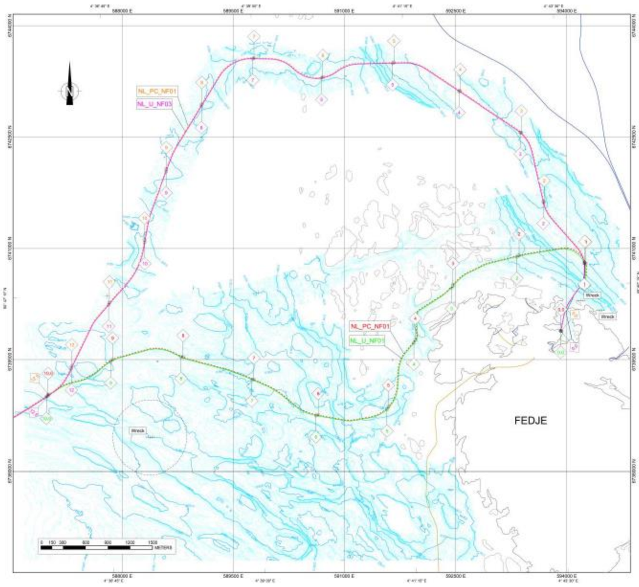


Figure 3-23 Umbilical and DC/FO route options in the North of Fedje

4. Existing pipeline/ cable crossings

The crossings of existing facilities (pipelines/cables) have been reviewed.

The existing pipelines/cables to be crossed will be protected with subsea rocks installation to provide a suitable cover (300mm) on top of these. The relevant dimensions (e.g. length and width) are taken from Table 3-9. The number/ rock volume of the supports at the crossings relevant to the umbilical route options from is summarised in Table 3-10. The estimated gravel volume to perform these 15 crossings is approx. 5495m3 for each umbilical and DC/FO route.

Table 3-9 Types of subsea rock installation

Intervention	Scope	Parameters	Dimensions
Pre-lay Supports	Umbilical overbending	Length (1)	5m
		Width (2)	10m
		Height	As required
		Slope	1:2
Crossings	Protection of existing pipelines and cables during Northern Lights umbilical installation	Length (1)	20m
		Width (2)	9m
		Height	To provide the required separation of min 0.3m between the existing pipeline or cable. Alternative methods like concrete matts can be considered if found beneficial.
		Slope	1:4
Protection	Umbilical protection: – against rolling boulders; – in fishing areas; – for ship traffic interaction.	Length (1)	As required
		Width (2)	2m
		Height	0.8m TOP: – against rolling boulders; – in fishing areas; – for ship traffic interaction:
		Slope	1:4

Note:
(1) Longitudinal to the umbilical;
(2) Across umbilical.

Table 3-10 Umbilical route options from Fedje: crossings list

Existing Crossed Facilities		$H_{Support}$	V_{gravel}	KP (m)		
Description	OD (m)	(m)	(m^3)	NL_U_NF01	NL_U_NF02	NL_U_NF03
36" Josepp Pipeline	0.914	1.40	637.7	15646	14946	18165
42" Gas Agard Transport Pipeline (P121)	1.067	1.50	720.0	32850	32150	35369
30" Gas Kvitebjorn Pipeline (P192)	0.762	1.20	490.2	45849	45149	48368
Power Cable Troll P60A	-	0.60	169.6	46036	45336	48555
36" Troll Gas Pipeline (P12)	0.914	1.40	637.7	46260	45560	48779
36" Troll Gas Pipeline (P11)	0.914	1.40	637.7	46417	45717	48936
36" Troll Gas Pipeline (P10)	0.914	1.40	637.7	46628	45928	49147
4" Troll Glycol Pipeline (P20)	0.102	0.60	169.6	46751	46051	49270
Cable Troll P60	0.054	0.50	132.0	51690	50990	54209
Cable Troll P61	0.075	0.50	132.0	51978	51278	54497
Cable Troll P62	0.075	0.50	132.0	52556	51856	55075
Power Cable Troll P61A	-	0.60	169.6	56920	56220	59439
Power Cable Troll P62A	-	0.60	169.6	57254	56554	59773
28" Oil Osberg A - Sture Pipeline (OTS)	0.711	1.20	490.2	71986	71286	74505
Martin Linge Power Cable (PFS)	-	0.60	169.6	80110	79410	82629

The final selected route(s) to be carried into the FEED phase are shown in Figure 3-24.

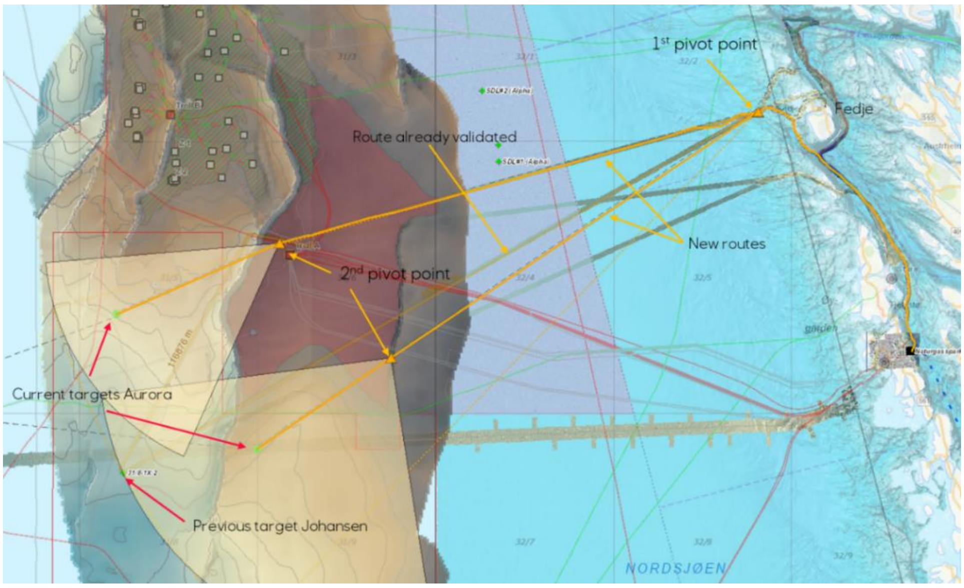


Figure 3-24 Illustration of FEED study routes to be examined

3.8.1.9 Spare part philosophy

Subsea controls
The following list describes the capital spare parts recommended for the subsea controls.

- 1 Spare Control Module
- 1 Spare DC/FO node
- 1 Spare subsea jumper of each ROV installable variant.

Umbilical and DC/FO
As this stage in the project, no repair/ intervention strategy has been established for the umbilical or the DC/FO, which is standard practice. During the FEED, the control system availability will be evaluated, and the strategy will then be established. Some contingency has however been included in the cost estimate, based on experience.

Subsea system
Complete back-up units for the VXT, FCM and flowbase will not be purchased for the phase 1 well. A sharing agreement with parallel NCS2017+ projects for standard NCS2017+ units, will be applied for. However, spare parts for main components on the VXT, FCM and flowbase will be purchased enabling repair/replacement of these main components. Additionally, spare connector seal assemblies/gaskets and casing hanger pack-offs will be purchased. This spare part philosophy will be further evaluated in the FEED phase.

3.8.1.10 Tie-in Spool & Tie-in systems

An evaluation of the different alternatives for the tie-in solutions has been performed during the concept screening and selection process.

Due to the time constraints related to preparation for a confirmation well, initiated mid-September, a contract for the delivery of the subsea structure and the wellhead system required for early drilling in November 2019 has been placed mid-October 2018. Use of standard equipment and standard catalogue solution to ensure timely delivery is necessary. Based on the result of the competitive tender for the confirmation well scenario, the tie-in system selected for Northern Lights is based on the HCS (Horizontal Connection) system, supplied by Aker Solutions (AKSO).

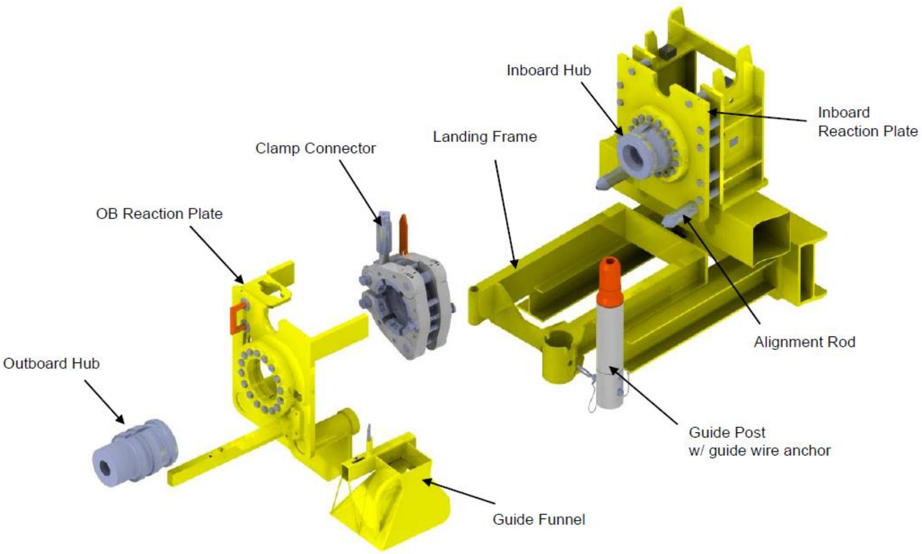


Figure 3-25 AKSO Horizontal Connection System (HCS), Exploded View

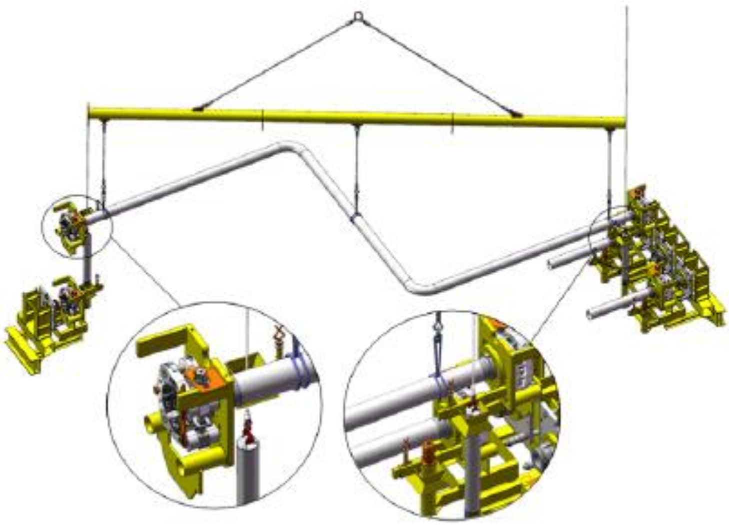


Figure 3-26 Deployment of a spool with HCS connections

The main benefit of the HCS is to reduce the overall cost during installation as well as having a minimum requirement of installation tooling.

The spool connections will be made up using a 12” HCS-R connection from Aker Solutions, as shown in Figure 3-27.

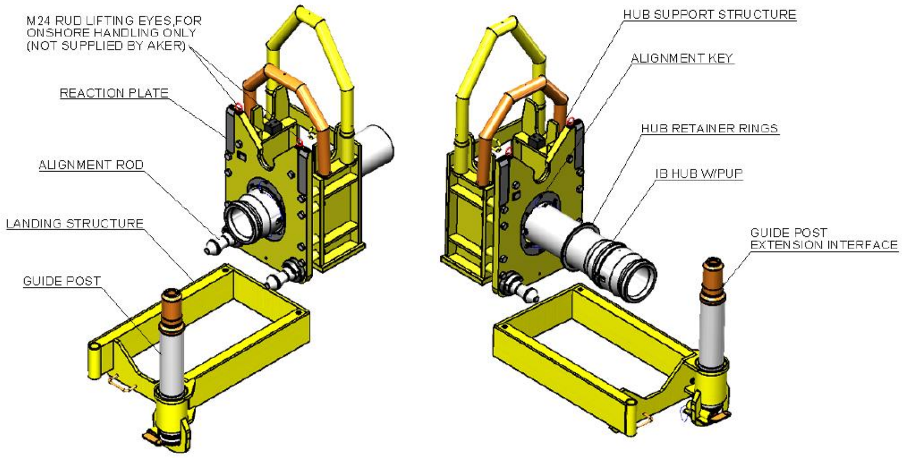


Figure 3-27 AKSO Horizontal Connection System (HCS) Outboard End, Rigid type

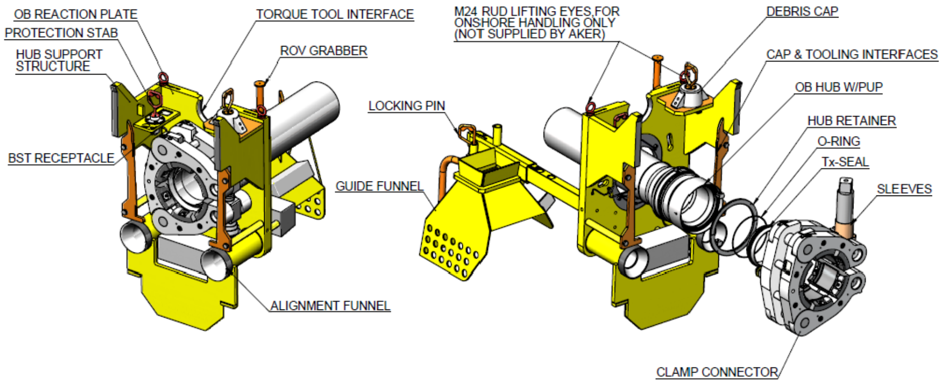


Figure 3-28 AKSO Horizontal Connection System (HCS) Inboard End, Rigid type

Figure 3-29 shows the spool landed in position, ready to be connected.

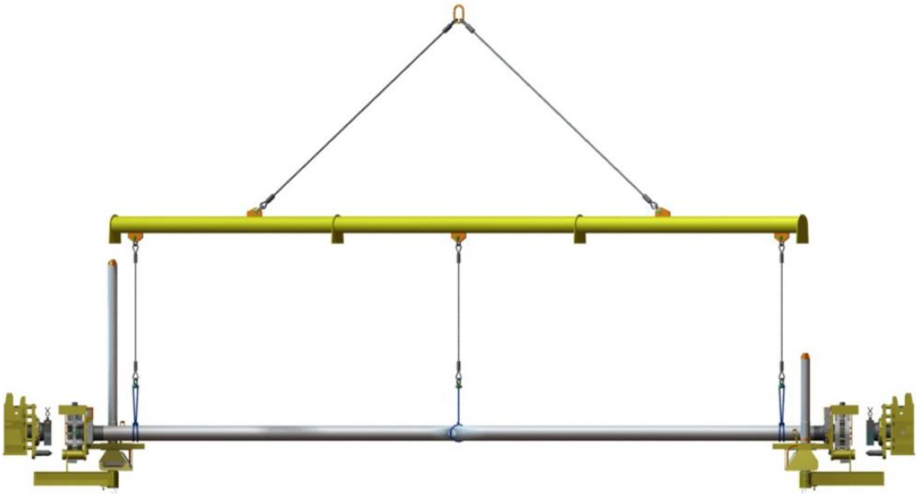


Figure 3-29 Spool with HCS-R termination landed, ready to be connected

The HCS-R is a tie-in system suitable for rigid in its R-version (as well as flexible and umbilical). It is designed to allow installation with or without guide wires. The base case for Northern Lights is without guide wires. The HCS utilizes lightweight ROV handled tools. Seal replacement as well as hub cleaning can be performed without retrieving the spool. The HCS is designed with a high load capacity and applicable for both shallow and deep water. Aurora water depth is about 300m, for which HCS is suitable.

3.8.1.11 Installation and Marine operations/ Removal

Installation campaigns

- The single satellite structure is planned to be installed from a construction vessel, with a minimum crane capacity of 250Te, during the autumn of 2019.
- The X-mas tree will be installed from a LWI vessel.
- The umbilical will be installed from a large carousel lay vessel with sufficient capacity to allow for installation of the whole umbilical length without splice. The DC/FO will be installed from a dedicated Alcatel vessel allowing installation and trenching of the whole length without splicing. The umbilical system can be installed in 2022, as long as the delivery of the umbilical system is specified accordingly. As an alternative, the umbilical system can be installed in 2023, to avoid potential SIMOPs with the pipeline laying operations.
- The metrology will be performed after completion of the pipelay operations.
- The rest of the subsea equipment installation, spool fabrication and installation, protection cover fabrication and installation, tie-in operations, testing and commissioning will be performed during the summer of 2023, to be completed with sufficient float before DG4. These operations will be completed from a smaller construction vessel, based on availability.

Removal

The satellite structure is designed to be removable. At the end of the injection period, the wells will be permanently plugged and abandoned. The structure can then be retrieved. All buried lines can be left in place. All exposed sections need to be cut and retrieved, and the extremities protected with stones installation. No obstruction to fishing by trawling should be left in place.

3.8.1.12 *Seabed intervention and protection design*

<u>Trenching of umbilical and DC/FO</u>

During the pre-FEED work, Saipem has examined new fishing data available to provide relevant conclusions for the umbilical and DC/FO protection measures against potential interference with fishing gears (e.g. area affected by fishing activities, fishing gear type, mass, velocities).

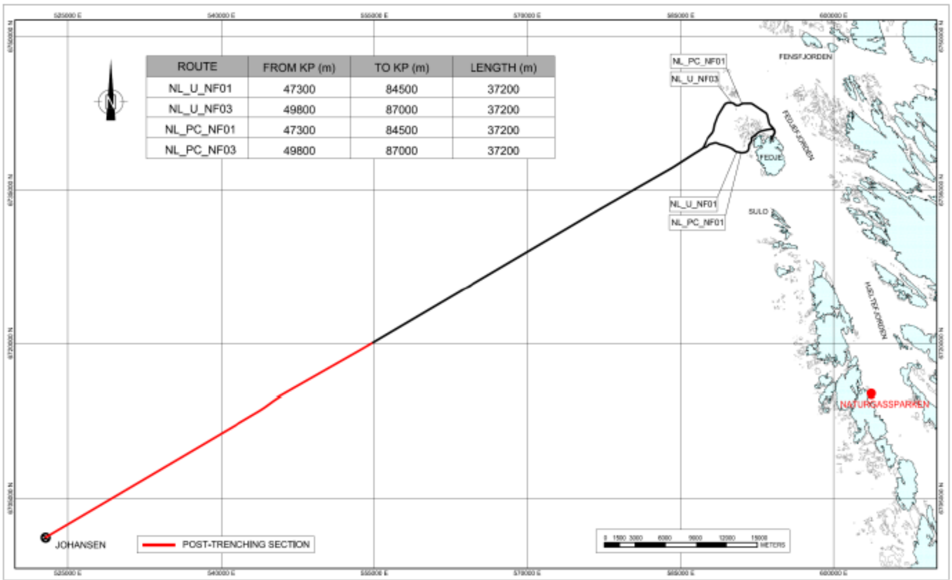


Figure 3-30 Umbilical Route Split Concept – Protection by post-trenching

Two main umbilical sections covering the whole routes have been identified with respect to the available fishing activities information. The umbilical protection against fishing activities have been implemented in accordance to the peculiarities of these two sections, in particular:

- Umbilical section from landfall at Fedje to East of the Troll field: this umbilical section is running from KP0 to KP47.3 for NL_U_NF01. In this section, no significant trawling activity has been recorded in the latest investigation. No protection is deemed necessary.
- Umbilical section West of 4°E and around the preliminary Johansen well site: this umbilical section is running from KP47.3 to KP84.5 for route NL_U_NF01. The corresponding length of these two umbilical sections is 37.2km. In this section significant fishing activities have been recorded with big fishing gears. Umbilical protection is mandatory by post-trenching (minimum burial of 0.5m).

<u>Recommendation</u>: Per default, the DC/FO cable is trenched during installation, along the entire route.
It is therefore recommended to trench it as the base case along the entire selected route.

For the concept selection and related cost estimate exercise, the recommendation would be to trench the fluid umbilical along the entire route. During the FEED study, a more detailed appraisal of the risk exposure and the control system reliability could provide the necessary input to conclude whether there is an opportunity to reduce the length of the trenched umbilical only to the last section recommended by Saipem, from KP47.3 to KP84.5 for route NL_U_NF01. The corresponding length of these two umbilical sections is 37.2km.

Rock installation pre-lay / post-lay

The overall rock volume designed for the routes which have been studied is shown in Figure 3-31 and Table 3-11.

This section provides the details of the rock volumes required for umbilical and DC/FO supports and protection for all the route options summarized previously.

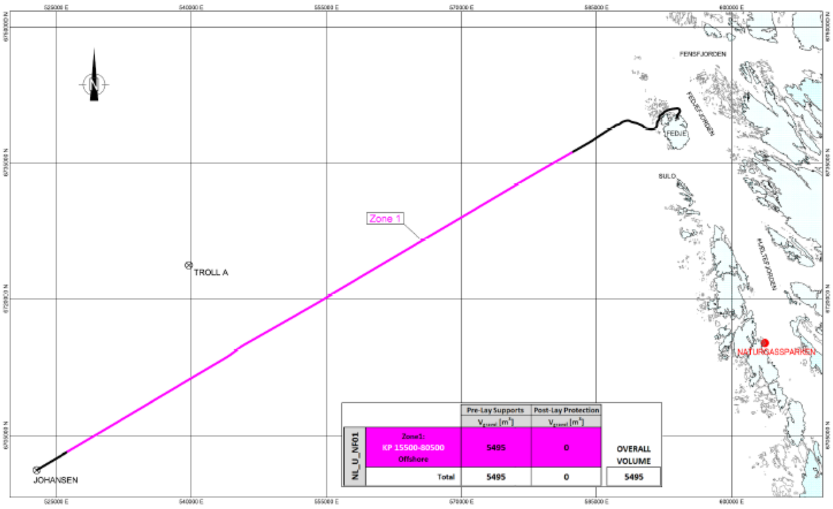


Figure 3-31 Umbilical Route NL_U_NF01 and DC/FO route NL_PC_NF01 - Rock Volumes

Table 3-11 Umbilical NL_U_NF01 – Rock Volumes Detailed Breakdown

	Pre-Lay Supports		Post-Lay Protection	
	KP [m]	V_{gravel} [m^3]	KP range [m]	V_{gravel} [m^3]
Zone1: KP 15500-80500 Offshore	15646	637.7		
	32850	720.0		
	45849	490.2		
	46036	169.6		
	46260	637.7		
	46417	637.7		
	46628	637.7		
	46751	169.6		
	51690	132.0		
	51978	132.0		
	52556	132.0		
	56920	169.6		
	57254	169.6		
	71986	490.2		
	80110	169.6		
		5495.4		**0.0**
Total		**5495.4**		**0.0**

Structure and connections protection

The single satellite structure includes both an overtrawlable hatch and two off Sealine Protection Covers (SPC) to ensure overtrawlability and dropped object protection of all critical parts.

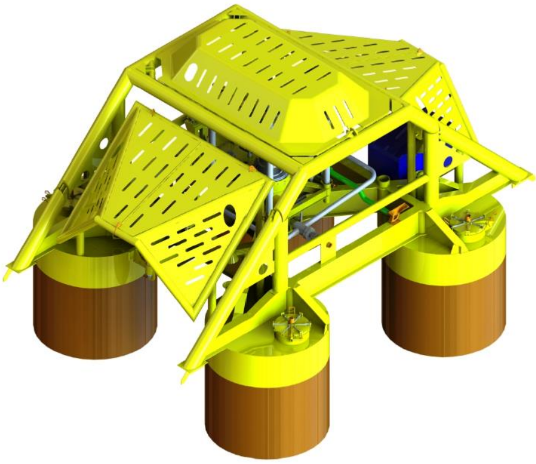


Figure 3-32 Northern Lights pilot satellite structure with suction anchors and trawl protection

Figure 3-33 Sealine Protection Cover (SPC, 2off)

Spool protection

The spool connecting the CO_2 pipeline end PLEM and the single well satellite structure will most likely be protected by the mean of GRP or steel protection covers, stabilised with rocks if necessary, to ensure overtrawlability and dropped object protection of all critical parts. Figure 3-34 and Figure 3-35 illustrate how a spool can be protected by GRP or steel covers.

Figure 3-34 Spool protection cover in GRP - illustration

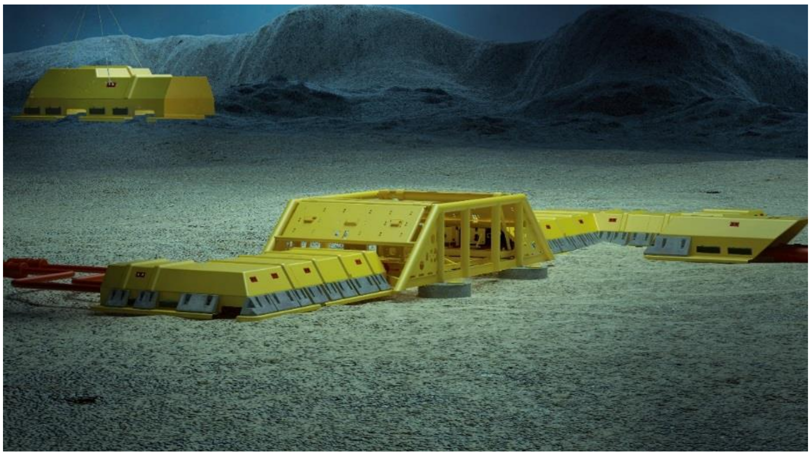


Figure 3-35 Spool protection covers - illustration

3.8.1.13 Operation of subsea facilities & intervention strategy

Well Completion and Intervention

A semi-submersible drilling rig is assumed used for drilling and completion of the well(s), since a water depth of 300 meters is too deep for a jack-up rig. The well(s) will be designed for possible intervention with coiled tubing, wireline and slick line. Downhole well intervention can be performed either by rig or RLWI vessel. Installation and retrieval of subsea system modules, including the X-mas tree, are planned performed by RLWI or IMR vessel.

Normal operations

The Northern Lights project shall inject CO_2 as single-phase liquid from shore to reservoir to avoid flow instability in the offshore injection system, avoid excessive fluid and equipment cooling during flow choking and maximise CO_2 storage volume. It will be important to secure continuous injection into the well, to maintain/achieve a good injectivity. The high reservoir pressure in Aurora entails liquid phase condition at the wellhead for all flowrates. A subsea choke will be used to secure liquid phase condition in the pipeline.

There is no minimum flowrate to secure liquid phase condition at the wellhead for this system (higher reservoir pressure and deep wells). However, there might be a limiting flowrate which is possible to regulate with use of a subsea choke.

Thus, the minimum possible flowrate in the injection system will depend on the minimum possible subsea choke opening. If a choke size of CV2 is used, this will result in a minimum flowrate of 0.12Mt/y. Given this flowrate (0.12Mt/y), it will be possible to maintain flowrate into the system for more than 20 days, assuming the planned onshore storage tank volume and pump(s) can deliver the minimum flowrate. CO_2 ship deliveries below this frequency will consequently result in batch operation of the system. A shut-in well may result in a reduced well injectivity, and it may take some time to regain full normal injectivity again. This may result in lower system injection capacity for a limited period. Consequence of this will be further addressed/detailed out in the next phase of the project.

Subsea Maintenance

The main philosophy for maintenance of the subsea facilities is to utilize redundancy in the system to be able to plan for corrective maintenance in campaigns. Typical corrective maintenance will be replacement of modules from an IMR-vessel.

Scheduled maintenance on the subsea system will be the testing of subsea valves and ESD functions. These operations will be performed from the control room, without the need for vessel support.

Subsea Inspection

Subsea structures are inspected for leakages and general condition status with regular intervals. The inspections are carried out by Inspection, Maintenance and Repair (IMR) vessels and will be planned as a common campaign with planned maintenance tasks.The yearly inspection is a general visual inspection of the satellite well covering the structure, X-mas tree, control module, pipeline and umbilical tie-in. Every fourth year, there will be an umbilical visual inspection, structure corrosion protection control and detailed visual inspection of the structure, X-mas tree, control module. pipeline and umbilical tie-in.

3.8.1.14 Flow assurance subsea system

Flow conditions

The reservoir pressure is expected to be sufficiently high to secure single phase condition at the subsea facility for all operation.

Pressure

Operational pressure on the subsea facilities will be ranging from about 60 to 150bar. Failure in operation may result in higher pressure. The highest-pressure sources from the onshore facility will be 345bar@subsea. But an even higher pressure source that may affect the X-mas tree and the umbilical system will be the potential high pressure that can be generated in the annulus A due to temperature variations during a shut-in. This high pressure must be taken into account during design.

Temperature

Operational temperature will be equal to the ambient sea temperature (3-9°C). Lower temperatures will be seen during depressurization operation in case of a leakage. Minimum temperature due to a subsea leakage will be -5°C. Lower temperatures are expected if a depressurization of the well is to be performed. Minimum design temperature of -18°C is evaluated to be sufficient for the design.

Fluid velocities

Maximum flowrate for phase 1 development of the project is 1.5Mt/y. This will result in a fluid velocity in a 124mm ID of ~ 5m/s. However, higher flowrate into the well may be desirable for future development to secure maximum utilization (given good injectivity). This may result in fluid velocities up to 8m/s. The flex loop design shall take this into account and sufficient strains shall be secured so that no flow induced vibrations occur on the system.

Subsea Choke dimensions

The fully open choke shall have a CV of minimum 100. This to avoid high pressure drops across the choke for max injection rates. To be able to operate with small flowrates in the system, it will be important to secure operation with a small choke opening subsea. It will not be possible to choke the flow from the onshore facility because this will result in unacceptable slugging conditions in the pipeline. Steady state operation with subsea choke opening of CV 1 to 2 is desirable to secure operation of flowrates down to 0.15Mt/y.

Hydrate control

The likelihood of hydrates is very small and the use of MEG for hydrate control will not be required during normal or transient operations. However, if hydrate plugs do occur, it will be important to have a connection point subsea where a vessel can be used to inject MEG towards the well, subsea equipment or pipeline.

3.8.1.15 Opportunities

Capital spare parts

If identical equipment is used on other projects in the NCS2017+, there is an opportunity to enter into an agreement to share spare parts.

All-electric

The technology qualification of all-electric actuators is progressing well, but it is uncertain when it will be sufficiently mature for the project to apply the technology. For the Phase 1 of Northern Lights project, it cannot be considered due to current schedule constraints, but for future extensions in the next phase of the project, All-electric might be an opportunity. The cost savings depend on the step-out length of the umbilical and DC/FO. Refer to All-electric part decision for more details.

Oseberg

Tie-in to Oseberg rather than Fedje reduces the umbilical and DC/FO cable length from about 85km to approximately 40km, based on the final well target. This could potentially lead to savings in the cost of both the fluid umbilical and the DC/FO, for the procurement and the installation campaigns. A §5 enquiry has been sent to Oseberg license but due to schedule constraints, the feasibility study has not yet been performed. Since no confirmation or estimates have been received from Oseberg, costs beyond the difference in umbilical and DC/FO length are difficult to consider.
For more details, refer to the selection of the Subsea control station location part-decision.

Umbilical trenching

In the cost estimate, the assumption is that the fluid umbilical will be trenched for most of the route (apart from 5% where it would be protected by the installation of stones if the soil conditions don't allow for trenching). A detailed assessment will be performed during the FEED to evaluate if some sections of the umbilical from Fedje to KP47.3 for the umbilical route NL_U_NF01 could be left unprotected.

3.8.2 Pipelines

3.8.2.1 General

The main facilities for the pipeline system are:

- Onshore pipeline at Naturgassparken with ESV arrangement, insulation joint and facilities for connection of pig receiver during operation
- Horizontal Directionally Drilled (HDD) tunnel as landfall solution
- Subsea pipeline from Naturgassparken to the well location in the Aurora reservoir
- Subsea Pipeline End Manifold (PLEM) with hub for spool connection to the satellite well and with hub for temporary pig receiver/future extension to a new well location

Figure 3-36 View showing HDD tunnel and pipeline approach to terminal

Several decisions have been taken during the concept phase. Of importance for the pipeline are:

- Outer diameter of the pipeline is 12 ¾''
- Material quality for the pipeline is seamless carbon-manganese steel with SMYS 450 suitable for installation by reeling, sour service, fracture arrest and enhanced dimension tolerances.
- Design pressure for the pipeline is 290 bar@+10m with a corresponding CO_2 transport capacity of approximately 5Mt/y

- Pipeline wall thickness for the first 7km is 17.5mm while the remaining pipeline will have a wall thickness of 15.9mm. No corrosion allowance is included as the CO_2 fluid will not contain any free water. The pipeline wall thickness is above the threshold needed at 11.5mm for a 12 ¾'' OD pipeline to prevent running ductile fractures.
- The first 7km of the pipeline will be designed with a low design temperature of -30^0 C while the remaining part of the pipeline will be designed with a low design temperature of -20^0 C. The low design temperature for the first part of the pipeline is to allow for a potential future reduction of the current onshore heating requirement to +1^0 C.
- The pipeline route is selected to be routed out from Naturgassparken through a Horizontal Directional Drilled (HDD) tunnel of 650m and then north along Hjeltefjorden turning out to the offshore area south of the Fedje island. The selected route is shown in Figure 3-37. This route will also be used for cost estimating for the Concept phase estimate. This pipeline route has a nominal length of 107.4km.

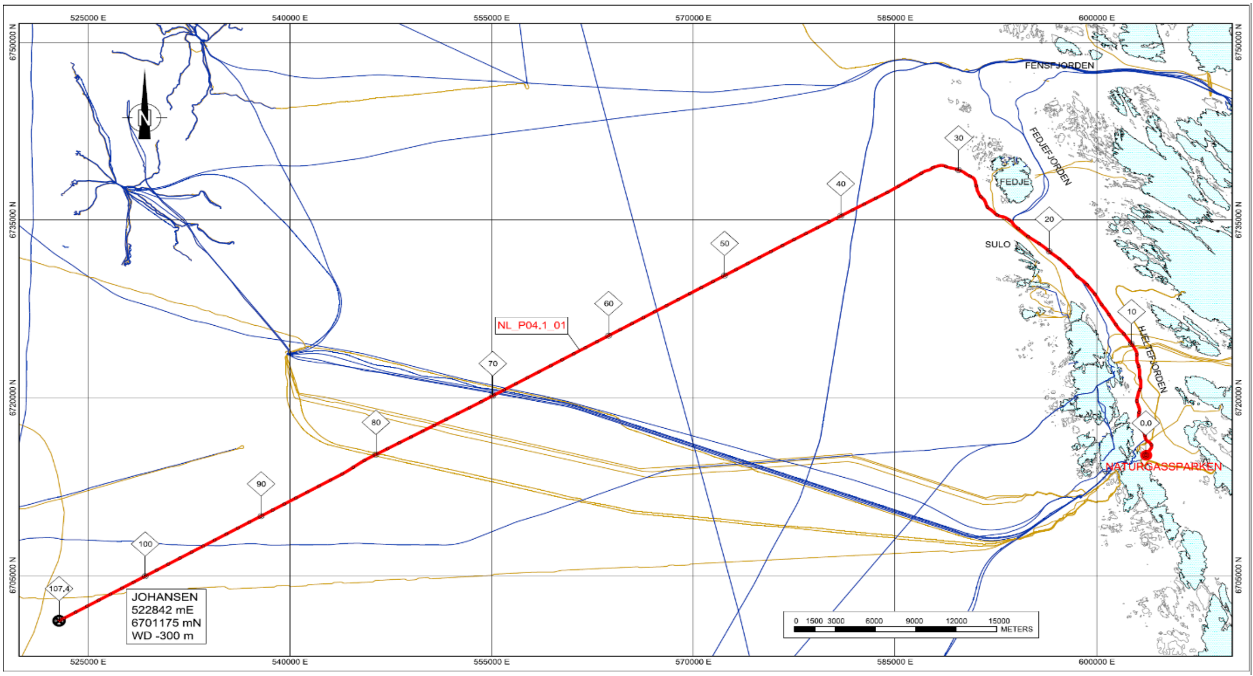


Figure 3-37 Selected route out to Aurora well location based on the Concept study

Due to the status of maturity for the subsurface work, two well targets will be used in the Aurora reservoir for the FEED phase study, one in Aurora West and one in Aurora East. Subsurface will, during FEED, decide the final well location in the Aurora reservoir. In order to progress engineering in the FEED phase two pipeline routes will be studied. An update will be made when the final well location is known. These initial routes to be studied in the FEED phase are shown in .

The final route will be surveyed during 2019 and will be input to the final FEED route design.

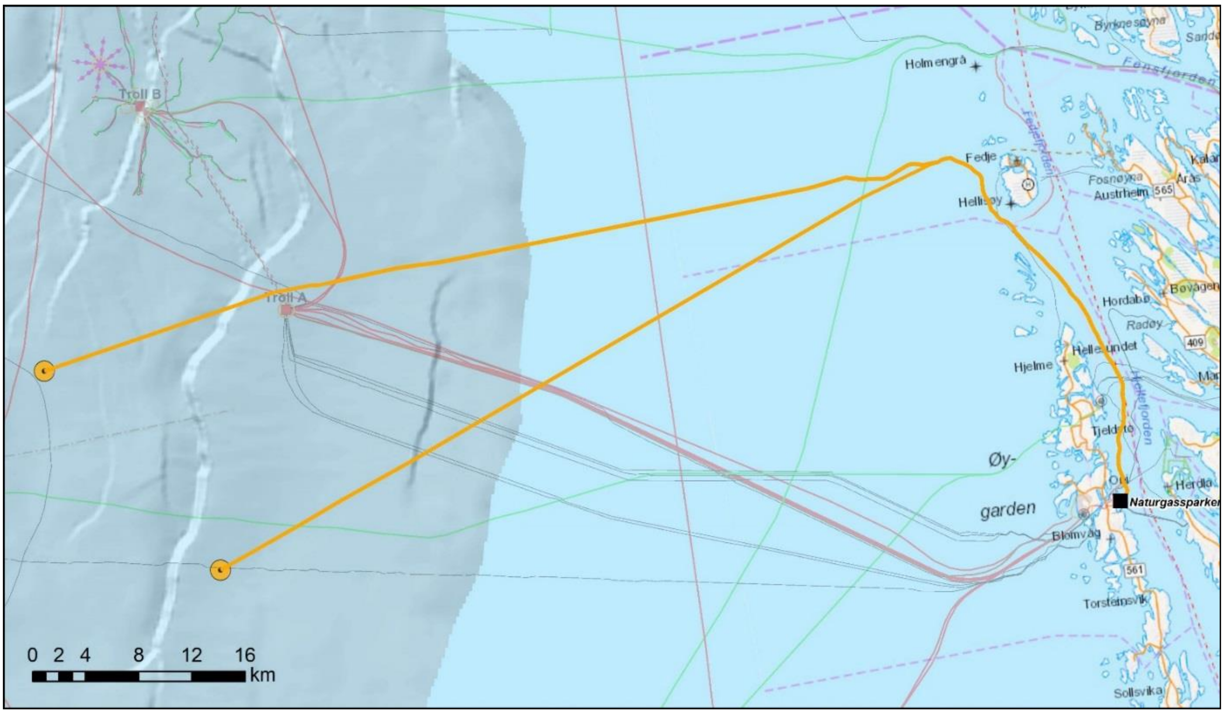


Figure 3-38 Initial FEED pipeline routes out from nearshore south of Fedje to two preliminary well targets in the Aurora reservoir.

The pipeline will be mainly unprotected in the nearshore area along Hjeltefjorden and south of the island Fedje as there is no bottom trawling in this area or other ship traffic that can cause damage to the pipeline. The pipeline will be protected in the offshore part of the route from bottom trawling.

The pipeline will be terminated by a Pipeline End Module (PLEM) with a 12'' valve for future connection to new well locations and a 6'' valve towards the satellite well spool.

The pipeline is feasible for installation both by the reeling method and by the S-lay method.

The pipeline will be pressure tested during commissioning with water. As part of the commissioning the pipeline will be dried by MEG swabbing before nitrogen is introduced into the pipeline as an intermediate and preservation medium before starting to inject the CO_2. No inspection pigging during commissioning or operations phase is planned for.

Leak detection during operation will be based on:

- Measurements of injected volumes from onshore and the subsea flow meter on the well
- Pressure gauges subsea and onshore upstream the ESV and downstream of an isolation valve permits pressure monitoring during shut-ins
- Regular subsea inspection program by ROV

The quality of the CO_2 will be monitored onshore before being injected into the pipeline as a prevention measure to ensure that the CO_2 will be within the CO_2 specification for critical components. The method and equipment to be used to perform the monitoring will be further investigated in the FEED phase of the project.

The main remaining uncertainties after the Concept phase being carried into the FEED phase are:

- The current concept is to commission the pipeline with nitrogen as an intermediate medium. When pressurising up the nitrogen prior to introducing CO_2 into the system the pressure in the subsea well tubing will be higher than the permanent export pressure pump capacity onshore. Mitigating actions are either to invest in a higher rate temporary or permanent injection pump or to investigate to separate the nitrogen and CO_2 by pigs to be able to control the process.
- The final well location is not known when entering into the FEED phase. Mitigating action is to do a staged FEED design as described and be ready to perform the seabed bathymetry survey and geotechnical survey during 2019.

3.8.2.2 System Description

The system schematic for the whole system is shown in Figure 3-39.

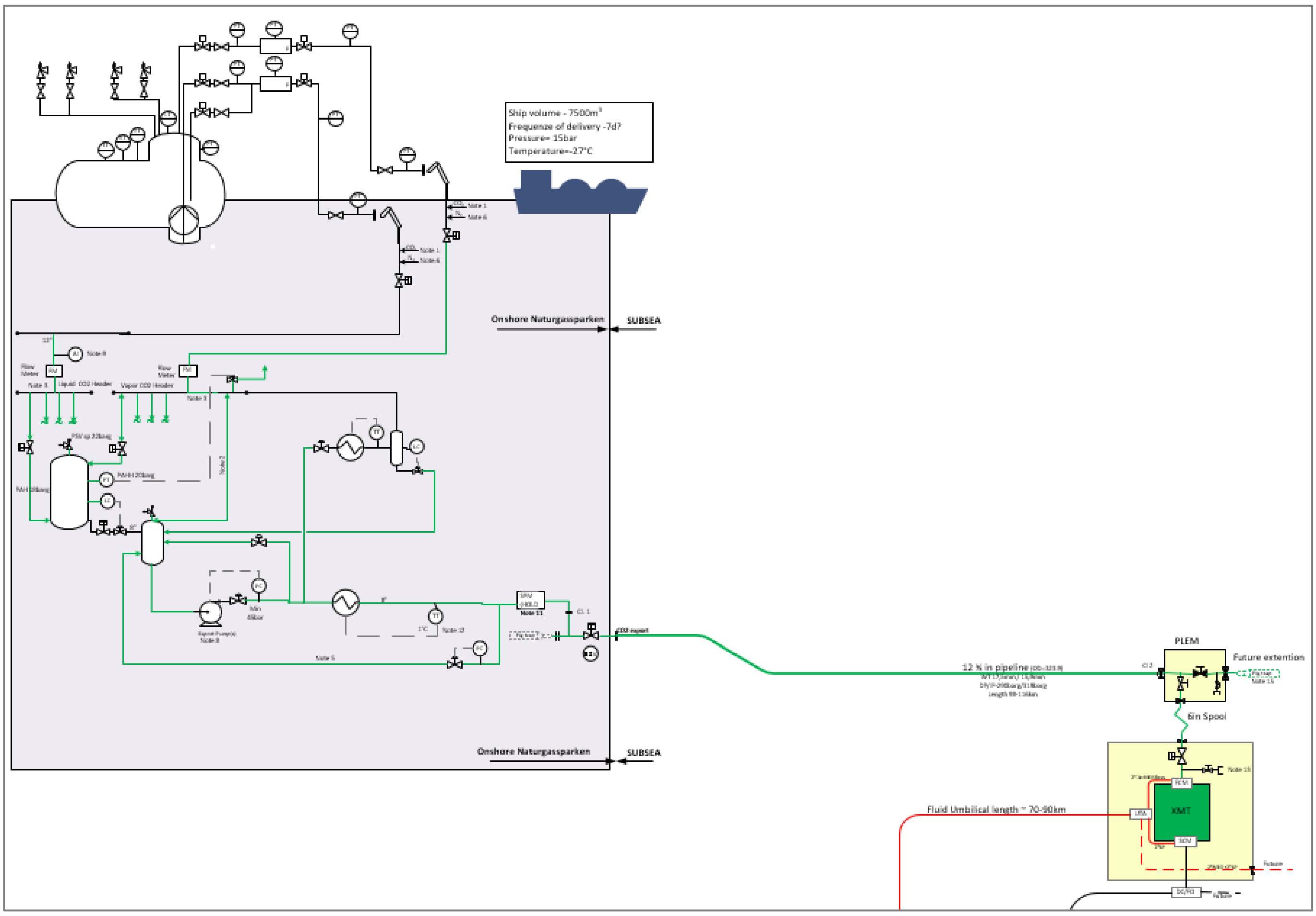


Figure 3-39 Schematic system overview – Onshore facilities, pipeline and subsea system (for illustration only)

The proposed system schematics for the onshore pipeline and safety system is shown in Figure 3-40.

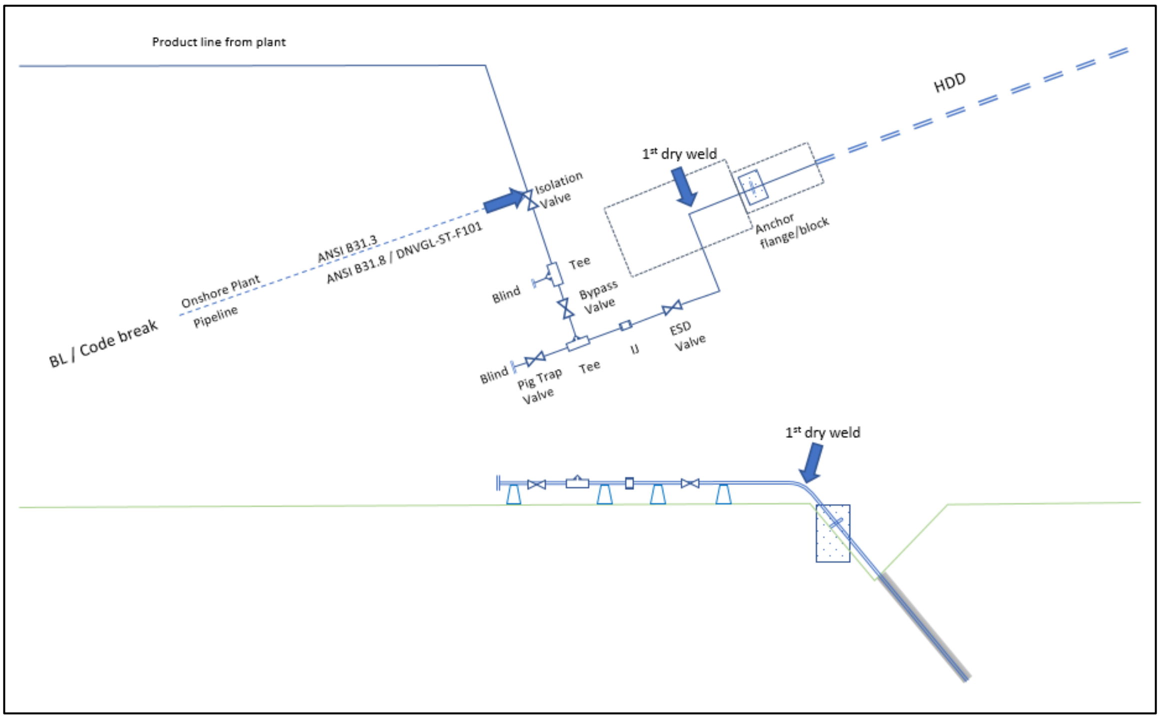


Figure 3-40 Code break between land terminal and pipeline.

System solution at the subsea end is shown in Figure 3-10. Subsea will provide the hubs and the design of the hubs to the Pipeline end manifold (PLEM).

3.8.2.3 Routing

The pipeline starts onshore inside the terminal area. The landfall is through a Horizontal Directionally Drilled (HDD) tunnel as shown in Figure 3-41 with indicative length 650m.

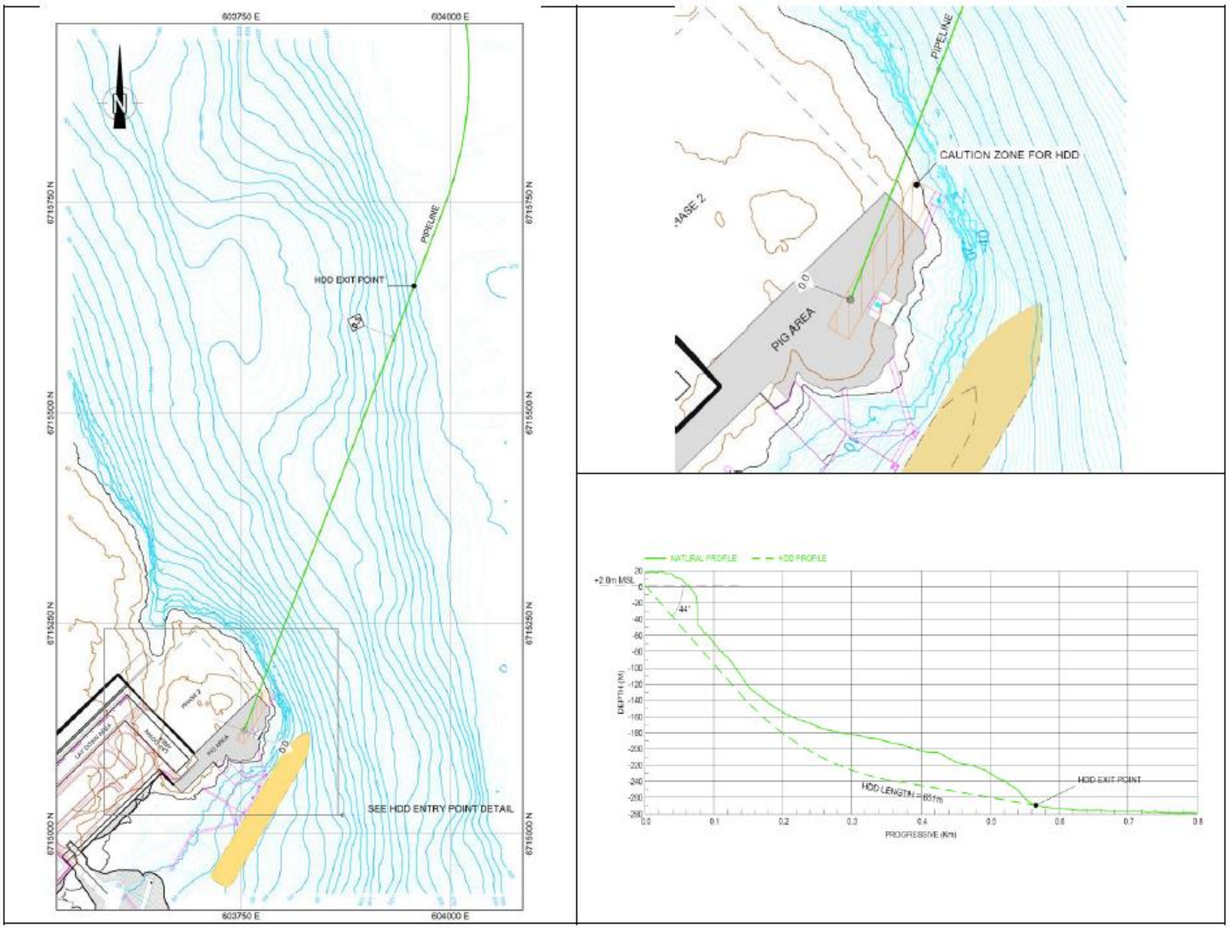


Figure 3-41 Schematic view of landfall solution (HDD tunnel)

The pipeline is then routed parallel with the existing 12 ¾'' Mongstad Gas Pipeline (MGR) north in Hjeltefjorden until it reached Fedjeosen. In Fedjeosen the pipeline turns to the north west and is routed up a steep slope from a water depth of approximately 550m in Fedjeosen to a point west of the Fedje island where it reaches a water depth of approximately 97m. From there the pipeline turns towards the west / south west towards the Aurora reservoir.

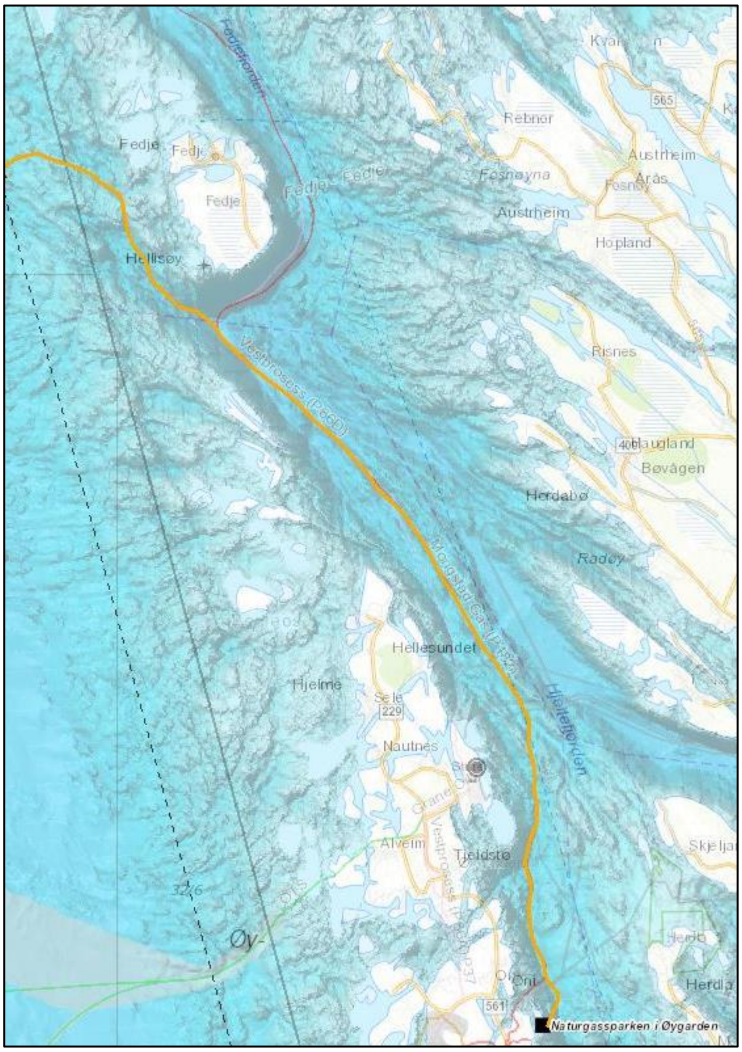


Figure 3-42 Northern Lights pipeline in parallel with MGR pipeline in Hjeltefjorden

The pipeline route in the area south of Fedje is very uneven with outcrops of rock as shown in Figure 3-51. Several subsea rock installations will be needed in order to prepare the seabed for installation of the pipeline.

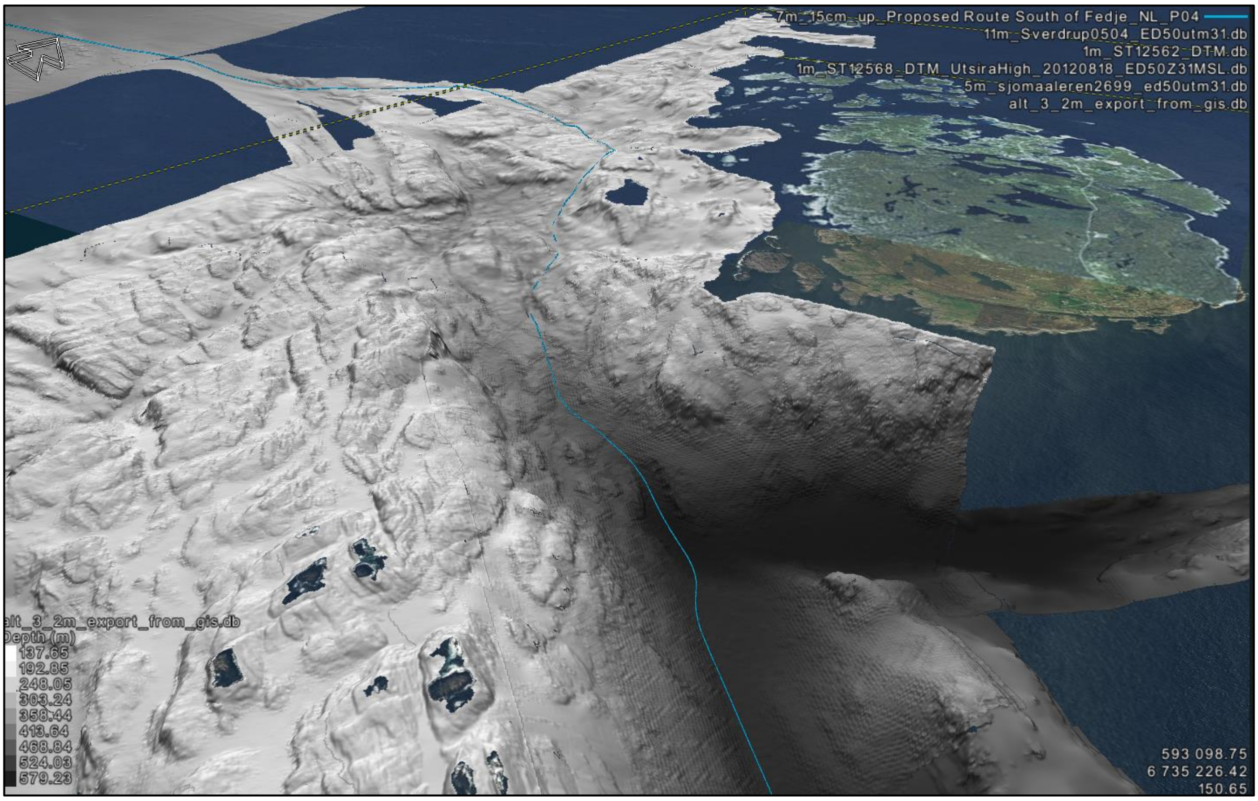


Figure 3-43 Northern Lights pipeline in terrain south of Fedje

Environmental sensitive areas

There are no designated marine nature conservation areas. A small area assigned as “very important with important nature type” with a large occurrence of scallops is crossed by the HDD tunnel as landfall solution, but the area will not be affected by the HDD or pipeline. This area is shown in Figure 3-44 by red colour. It should also be noted that scallops normally only grow in nearly flat seabed with sand. It is not expected to find these kind of seabed features in the landfall area[5].

[5] *“A small minority of scallop species live cemented to rocky substrates as adults, while others attach themselves to stationary or rooted objects such as sea grass at some point in their lives by means of a filament they secrete called a byssal thread. The majority of species, however, live recumbent on sandy substrates.”* (source Wikipedia)

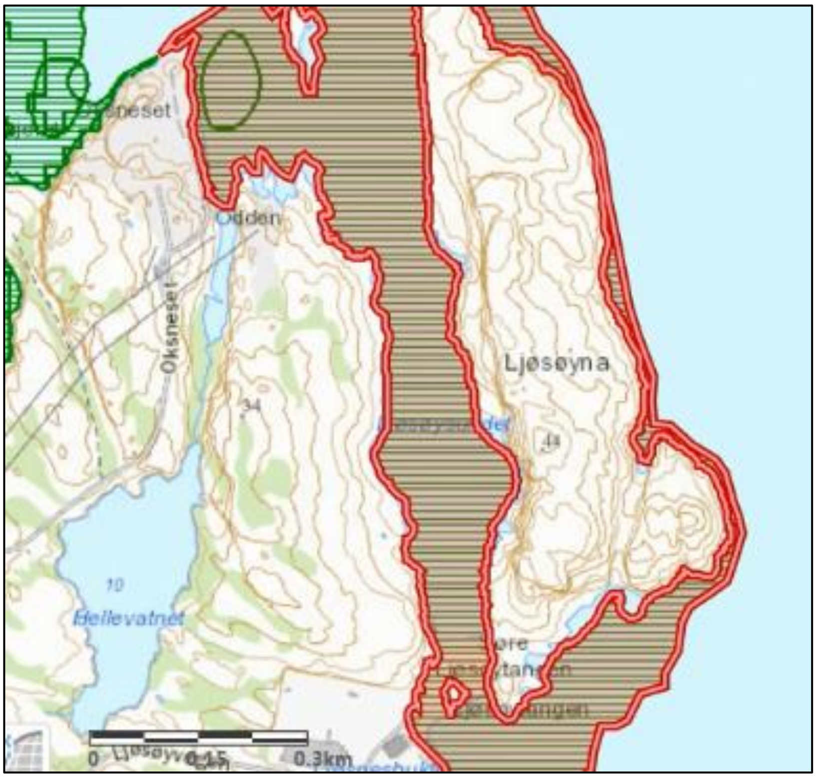


Figure 3-44 Important nature type near the landfall.

The pipeline route after this point will cross an area holding cold water corals and possible coral gardens, and with a high potential of so far not-identified corals. At present time, the shortest distance is approximately 40m to the nearest identified possible coral location, see Figure 3-45. Corals are classified as important nature resources with authority focus, and conflict with these resources shall be minimized. The presence and extension of these coral structures should be confirmed as part of the optimization of the pipeline routes to minimize conflict with them. The corals indicated in the figure was identified during survey for Johan Sverdrup oil pipeline during 2015 in SW-NE direction. To be further evaluated during next phase based on survey campaign for Northern Lights in 2019.

Figure 3-45 Brown line: pipeline route; Pale green: possible coral gardens and reefs (Equinor data) at approximately around KP35.

The pipeline route is north of the WW2 U-boat U-864 with a distance of approximately 0,5 km away from the 1 km diameter prohibition zone and is also clear of the prohibition zone around U-boat U-486 (Figure 3-46).

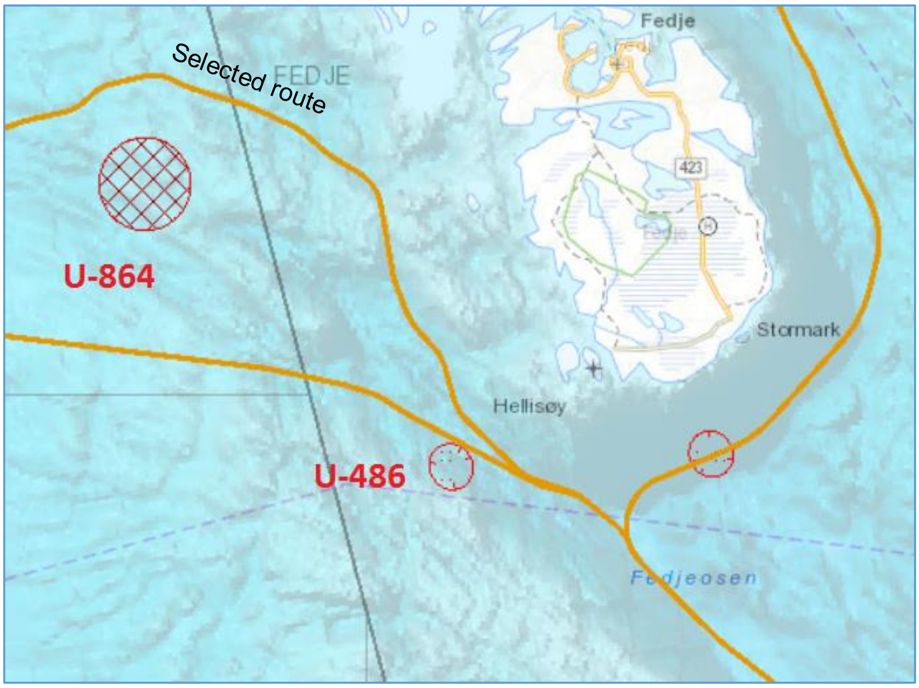


Figure 3-46 Restriction zones around submarine wrecks south of Fedje

The proximity of the pipeline route to the submarine wreck U-864 and the risk for contamination of bottom sea fauna (impact on sea food quality) in relation with pipeline lay out activities have been raised and discussed with the Norwegian

Food Safety Authority (Mattilsynet) and the Norwegian Coastal Administration (Kystverket) at Hordaland regional plan forum meeting held 27 February 2018 in Bergen. The Food Safety Authority mentioned during that meeting and confirmed as part of its hearing comments to the zoning plan proposal that such risk does not exist when the pipeline route is located 1000 m from the wreck (or 500 m outside the prohibition/restriction zone) as planned. This statement was controlled and supported by the Norwegian Coastal Administration. This is also supported by the findings from the Institute of Marine Research (responsible for measuring mercury in fish and other seafood near the wreck of U-864 off Fedje) published in 2018 and showing that the operation performed by the Norwegian Coastal agency in 2016 laying down a counter filling closed to the wreck for stabilizing purpose did not results in increased mercury levels in the analyzed organisms. In the state proposal for the national budget for 2019 it is proposed to cover U-864 with rock within 2020.

Right of way

The Plan and building Act requires that the pipeline out to 1Nm outside the territorial boarder (Grunnlinje) is subject to a zoning plan, with a corresponding zoning plan program and public consultation processes.

Several route options have been out or public hearing and input from this process has been used for the final nearshore route selection.

The zoning area in the nearshore area for the final route is shown in Figure 3-47.

No other areas are concerned with right of way issues as the pipeline is leaving onshore from inside the onshore terminal area and as such will be handled by the onshore terminal area acquisition.

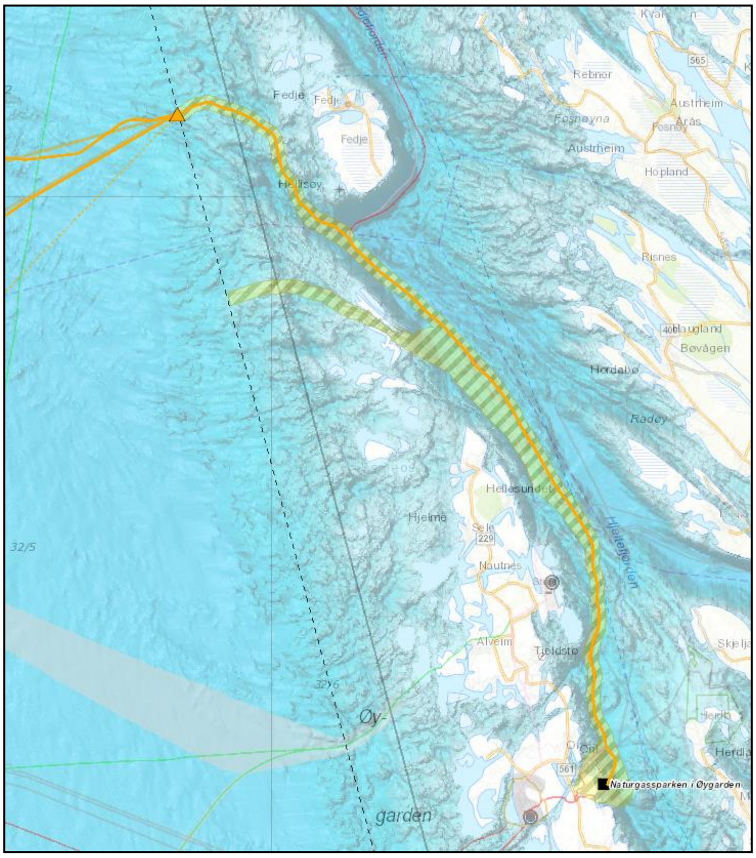


Figure 3-47 Zoning plan program area (in green)

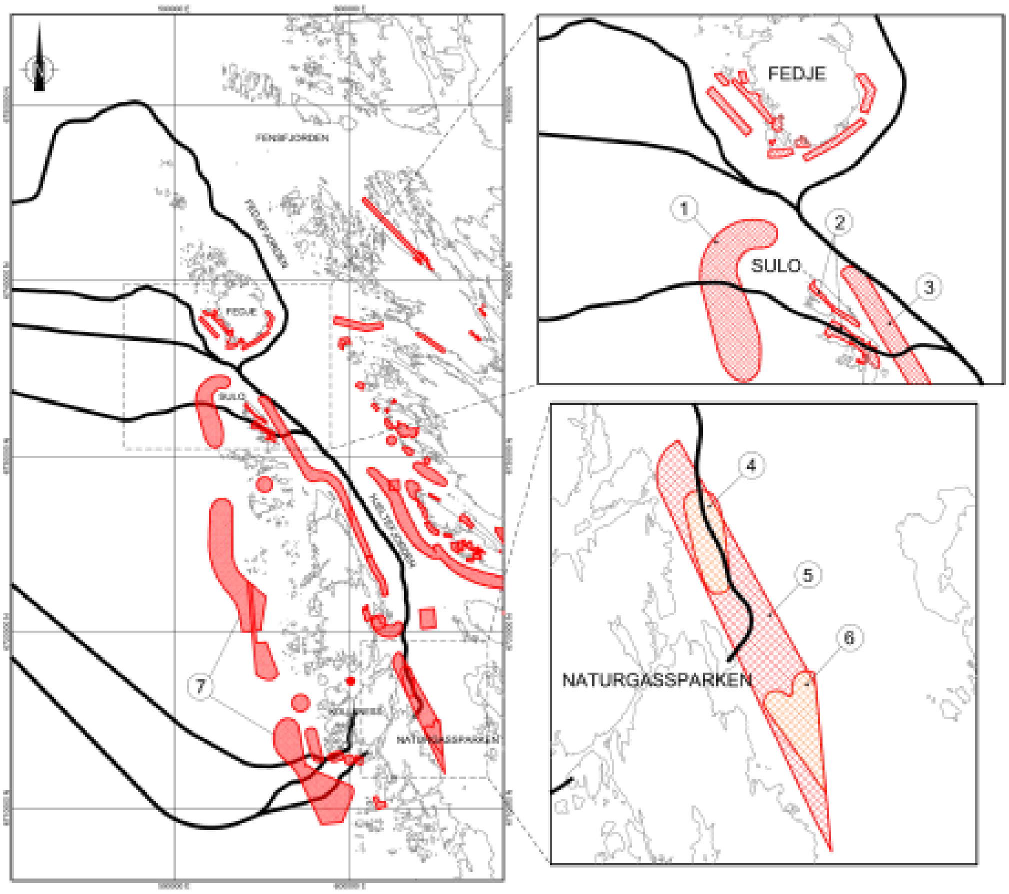
A zoning planning program has been issued for public hearing.

<u>Third party activities</u>

The following areas are identified as third-party activities for the selected concept selected pipeline route:

- Impact on fishing industry
- Military activities

There are several nearshore areas where fishing activities occurs, see Figure 3-48.



1) FISHING LOCATION, BY USE OF PASSIVE FISHING GEARS NETS. (LOCAL PROFESSIONAL FISHERMEN + LEISURE/TOURIST FISHING ACTIVITIES)
2) LOCATIONS FOR TEMPORARY MOORING AND SECURING OF A NET ENCLOSURE HOLDING A LIVING FISH CATCH FOR A PERIOD UNTIL THE CATCH IS SOLD LIVE TO THE BUYERS. ("LASSETIING")
3) FISHING LOCATION, BY USE OF PASSIVE FISHING GEARS NETS. (LOCAL PROFESSIONAL FISHERMEN + LEISURE/TOURIST FISHING ACTIVITIES)
4) FISHING LOCATION, BY USE OF ACTIVE FISHING GEARS TRAWL. AREA FOR TRAWLING AFTER PRAWNS. (LOCAL PROFESSIONAL FISHERMEN)
5) FISHING LOCATION, BY USE OF PASSIVE FISHING GEARS NETS. (LOCAL PROFESSIONAL FISHERMEN + LEISURE/TOURIST FISHING ACTIVITIES)
6) FISHING LOCATION, BY USE OF ACTIVE FISHING GEARS TRAWL. AREA FOR TRAWLING AFTER PRAWNS. (LOCAL PROFESSIONAL FISHERMEN)
7) FISHING LOCATION, BY USE OF ACTIVE FISHING GEARS SEINE/CASTING NET. FISHING FOR HERRING DURING THE SPAWNING MIGRATION PERIOD. (LOCAL PROFESSIONAL FISHERMEN + LEISURE/TOURIST FISHING ACTIVITIES)

Figure 3-48 Nearshore fishing areas

There are in general frequently trawling activity by larger vessels using heavy fishing gears in the offshore waters west of the territorial boarder (Grunnlinje), and with a high frequency in the south west part of the Aurora area.

The Norwegian Fishermen's Association (Norges Fiskarlag- NFA) has in the consultation of the zoning plan program stated:

- They are disappointed with the change from Smeaheia to Johansen formation, resulting in increased conflict with the fisheries interests.
- Referring to previous comments from the Fishery Directorate, stating that new pipeline route should be located within the corridors holding existing infrastructures in order to reduce potential conflicts of interest. They do not recommend a new routing south of Fedje, but prefer either north of Fedje or the southernmost

route alternative (Kollsnes). Also offshore the pipeline route should follow existing infrastructure to the extent possible.

Stakeholder engagement with both NFA and Fishery Directorate to clarify reasons and possible abatement measures to reduce conflicts is planned. A meeting the Fishery authorities has been held in August to explain the reasoning for selecting the route. The outcome of the meeting was that the Fishery Directorate maintained their recommendation of that the pipeline should follow existing infrastructure to the extent possible.
A corresponding meeting with the NFA is planned to be organised during the FEED phase.

There is a military training activity zone in Hjeltefjorden. Military authorities have been consulted during the consultation period of both the program for the zoning plan and the program for the impact assessment, no comments received. Military authorities to be informed about and coordinate marine operations versus military activity.

Crossing of existing and planned infrastructure

The pipeline will cross several other infrastructures on the route. All crossing agreements with the owners will be made during the execution phase. Each crossing will have its specific design as part of the crossing agreement. The crossings for the selected concept route to the field is shown in Table 3-12. These crossings might change depending on the final selected well target in the Aurora reservoir.

Table 3-12 Crossing list for route south of Troll

Crossing List - Route NL_P04.1			
Description	**OD (m)**	**Service**	**Reference**
BKK Power Cable Ljøsøysundet-Kuvågen 2	-	Existing	EQUINOR Database
BKK Power Cable Ljøsøysundet-Kuvågen 1	-	Existing	EQUINOR Database
BKK Power Cable Ljøsøysundet-Kuvågen 3	-	Existing	EQUINOR Database
BKK Power Cable Ljøsøysundet-Sætrevika	-	Existing	EQUINOR Database
12" Mongstad Gassrørledning (P182) - EVM	0.324	Existing	EQUINOR Database
BKK Power Cable Sture-Skansen	0.187	Existing	EQUINOR Database
Unknown Cable 01	-	Existing	Norwegian Authority Database
BKK Power Cable Sture-Storneset	0.050	Existing	EQUINOR Database
BKK Power Cable Ådneset-Storneset	0.110	Existing	EQUINOR Database
TELENOR Communication Cable Ådneset-Ellingsviki	0.110	Existing	EQUINOR Database
BKK Power Cable Ådneset - Klubben (Toska)	0.110	Existing	EQUINOR Database
12" Vestprosess Pipeline P86D (VPS)	0.324	Existing	EQUINOR Database
TELENOR Communication Cable Fedje-Hellesøy	-	Existing	EQUINOR Database
36" Josepp Pipeline	0.914	Planned	EQUINOR Database
42" Gas Agard Transport Pipeline (P121)	1.067	Existing	EQUINOR Database
30" Gas Kvitebjorn Pipeline (P192)	0.762	Existing	EQUINOR Database
Power Cable Troll P60A	-	Existing	EQUINOR Database
36" Troll Gas Pipeline (P12)	0.914	Existing	EQUINOR Database
36" Troll Gas Pipeline (P11)	0.914	Existing	EQUINOR Database
36" Troll Gas Pipeline (P10)	0.914	Existing	EQUINOR Database
4" Troll Glycol Pipeline (P20)	0.102	Existing	EQUINOR Database
Cable Troll P60	0.054	Existing	EQUINOR Database
Cable Troll P61	0.075	Existing	EQUINOR Database
Cable Troll P62	0.075	Existing	EQUINOR Database
Power Cable Troll P61A	-	Existing	EQUINOR Database
Power Cable Troll P62A	-	Existing	EQUINOR Database
28" Oil Osberg A - Sture Pipeline (OTS)	0.711	Existing	EQUINOR Database
Martin Linge Power Cable (PFS)	-	Existing	EQUINOR Database

3.8.2.4 Mechanical Design

Seamless carbon-manganese steel with SMYS 450 FPDS is selected for the CO_2 pipeline for increased capacity for fracture arrest, plastic deformation, enhanced dimensional tolerances and prevention of HISC.
The CO_2 is dry under normal operations. During planned shutdown, the pressure shall be kept sufficiently high to avoid risk of free water and of vapor forming. The CO_2 pipeline can therefore be designed without any corrosion allowance.

The pipeline wall thickness calculation has been performed according to DNVGL-ST-F101, considering the following design criteria:

- Pressure containment due to internal over pressure;
- System pressure test;
- System collapse due to external over pressure;
- Propagation buckling;
- Installation by reeling.
- Fracture arrest ensured through fracture control plan

Fracture control plan

The calculations and numerical simulations of the Northern Lights pipeline demonstrate that adoption of the Battelle two curve method with ISO 27913 or DNVGL RP-F104 arrest pressure corrections for CO_2 leads to a robust arrest assessment with significant margin to a critical wall thickness. With these factors now verified for this specific case, the otherwise straightforward fracture arrest methodology is considered fit for use in FEED and detail design without the need to resort to full-scale testing.

Coating

The selected coating for the pipeline is FBE + adhesive + PE according Equinor requirements. The field joint coating shall be compatible with the pipeline coating.

Cathodic protection

Active protection is achieved by cathodic protection system made of sacrificial bracelet anodes designed in accordance to NORSOK M-503. Cathodic protection system for onshore and offshore sections will be defined assuming that electrically sectioning between them will be achieved by installation of an isolating joint.
For the above ground installation painting system shall be applied.

Fatigue

Free-span dynamic analyses have been performed, in accordance to DNV-RP-F105 in order to identify the allowable span length and to support the selection of different route alternatives. All freespans in excess of the allowable length have been corrected by seabed rock installation to reduce the freespan of the pipeline.

Trawl impact loads

The pipeline-trawl gear interaction has been analysed referring to the following interaction phases:

- Impact, including impact energy evaluation. Assessment of bare steel pipe to withstand impact forces.
- Pull-over, including interaction force calculation and analysis of pipe response during and after fishing gear interference.
- Hooking, possibly linked to the formation of free spans induced by sea-bottom unevenness, including the analysis of pipe response after lift off from seabed.

From the analysis conducted it is concluded that the pipeline in areas with bottom trawling activities needs to be protected either by trenching the pipeline, rock installation on the pipeline or a combination.

Further and more refined analysis will be performed during the FEED. This could potentially relax the requirements defined in the concept phase to protecting the pipeline.

Ship traffic analysis

AIS ship traffic data have been collected in 5 specific areas in proximity of major vessel routes (see Figure 3-49). Based on the elaborated number of crossings, ship characteristics and occurrence of incidents, the frequency of ship traffic interaction with the pipeline has been assessed and compared with the DNVGL target criteria expressed as failure frequency of pipeline km per year.

Results show that in none of the analysed locations the interaction frequency exceeds 10^{-5} occurrence/km/year, thus the DNVGL criteria on the failure probability is met. On this basis no need of protection against ship traffic is identified.

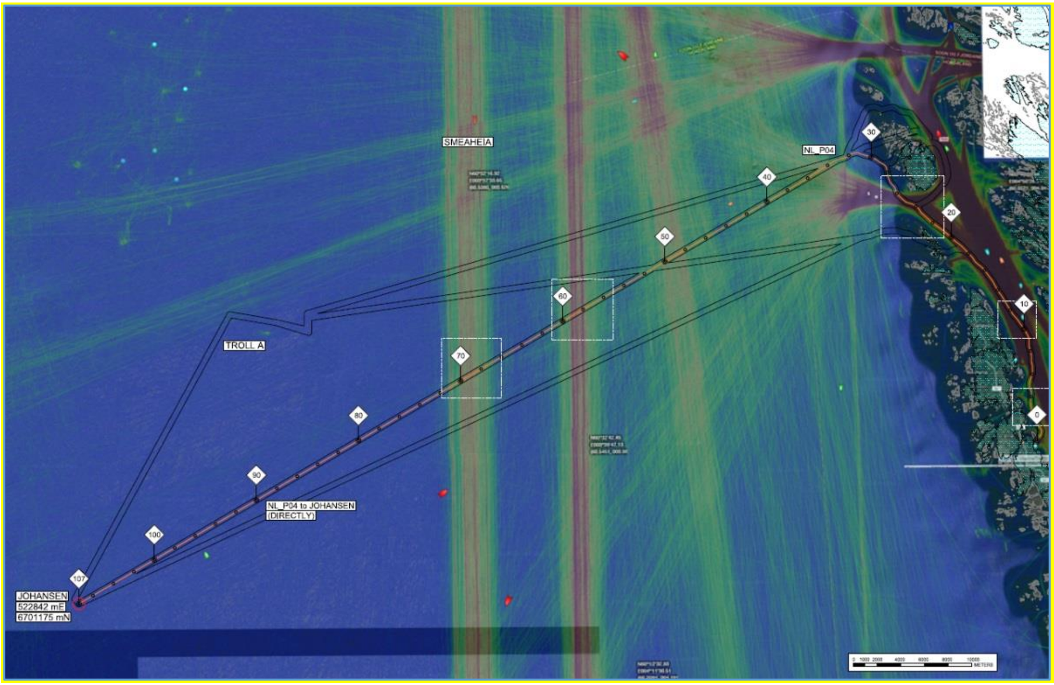


Figure 3-49 Pipeline route and areas of interest covered by AIS data

3.8.2.5 Seabed Intervention and Protection Design

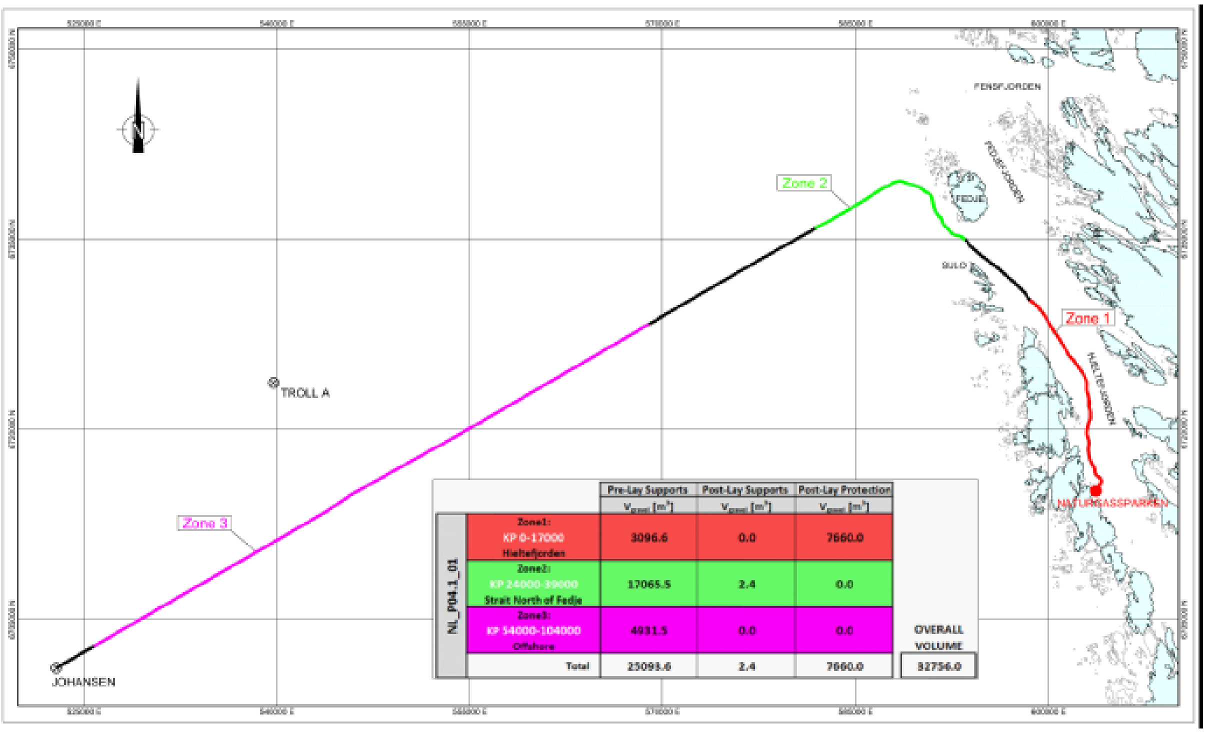
The four main pipeline sections covering the whole route have been identified with respect to the available fishing activities and ship traffic information. No protection is required against all the threats posed by the pipeline route interference with commercial ship traffic. The pipeline protection against fishing activities have been implemented in accordance to the peculiarities of these four sections, notably:

- **Pipeline section within Hjeltenfjorden:** this pipeline section is running from approximately **KP0** to **KP25**. Based on the input data it is concluded that no protection is required. This conclusion is applicable if trawl gears up to **300kg** are confirmed to be used in the area affected by bottom trawling. This will be confirmed during the FEED phase. In case, larger devices are recorded, protection measure shall be implemented from **KP1.6** to **KP3.3** (not included in the present design).
- **Pipeline section south of Fedje:** This pipeline section is running from approximately **KP25** to **KP34** for both of the south of Fedje routes). In this section no significant trawling activity has been recorded in the latest investigation and the terrain is very uneven so the likelihood of trawling in this area can be disregarded.

- **Pipeline section from Fedje to East of the Troll field:** this pipeline section is running from approximately **KP34** to **KP70**. In this section no significant trawling activity has been recorded in the latest investigation. However, the seabed in this area is flat and can be subject to bottom trawling. As it cannot be ruled out during the concept phase that there will be bottom trawling in the future, this area is in this phase of the design assumed to be protected from trawling. Analyses have not yet been performed, but it is assumed that in this section the pipeline will be fully trenched.
- **Pipeline section West of 4°E and around the preliminary Johansen well site:** this pipeline section is running from approx. **KP70** to **KP107** for route shown in Figure 3-50. In this section significant fishing activities have been recorded with heavy fishing gears (clump weights with weights more than 2 Te). Pipeline protection is mandatory by post-trenching. No specific requirement has been given at this stage to cover on the top of the pipe as this will be further investigated in the next phase.

The pipeline will be protected at the crossings and in the trawl area the free spans will be filled-in to avoid hooking. At the end of the pipeline the PLEM will be protected by overtrawling with a protection cover stabilised from impacts with rock supports.

The distribution of the subsea rock volumes for supports excluding crossings for the route is shown in Figure 3-50. The subsea pre- and post-installation work in the nearshore area is shown in Figure 3-51.



	Pre-Lay Supports V_{gravel} [m^3]	Post-Lay Supports V_{gravel} [m^3]	Post-Lay Protection V_{gravel} [m^3]	
Zone1: KP 0-17000 Hieltefjorden	3096.6	0.0	7660.0	
Zone2: KP 24000-39000 Strait North of Fedje	17065.5	2.4	0.0	
Zone3: KP 54000-104000 Offshore	4931.5	0.0	0.0	OVERALL VOLUME
Total	25093.6	2.4	7660.0	32756.0

Figure 3-50 Subsea rock volumes for pre-lay and post lay supports for route

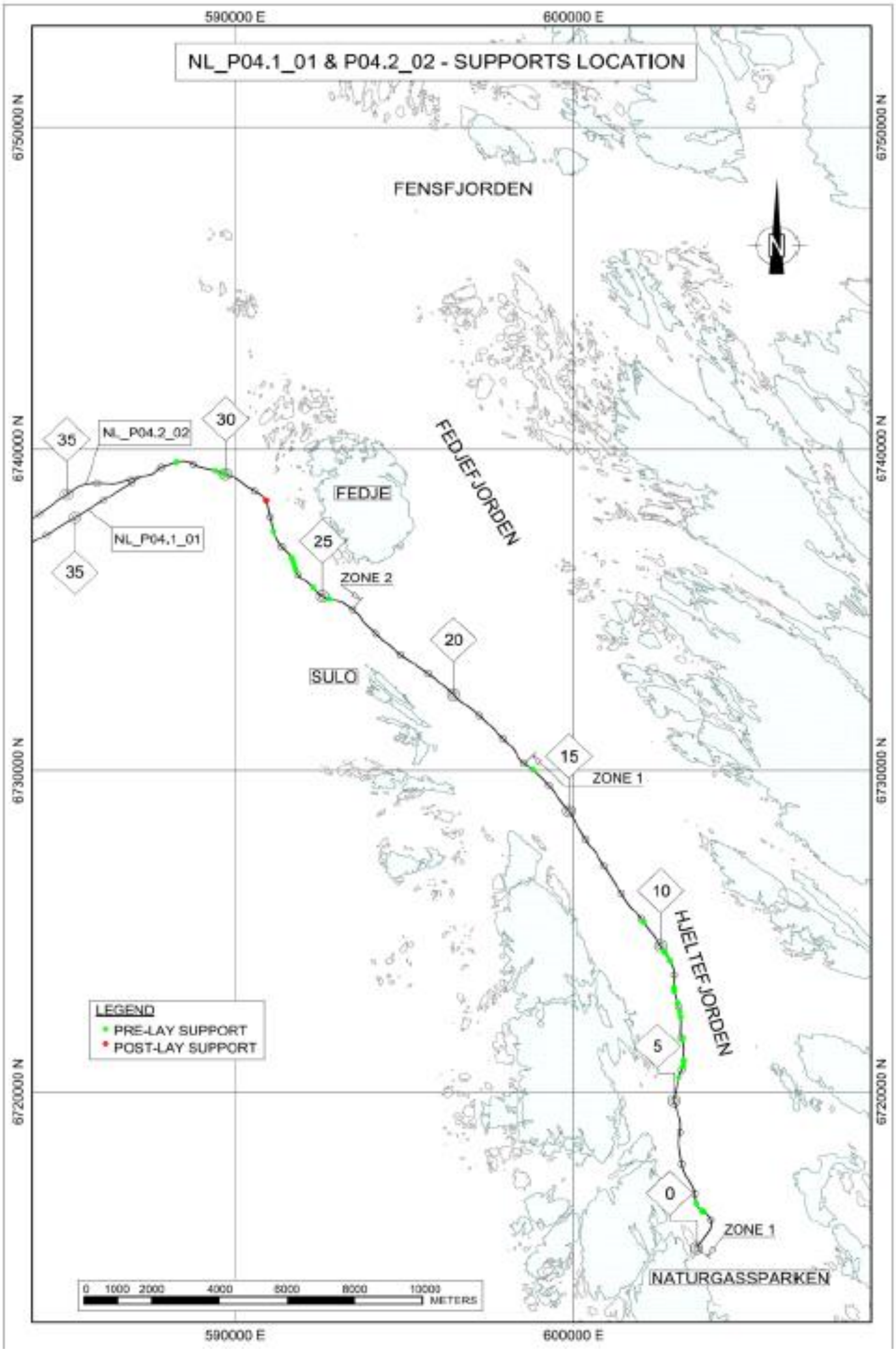


Figure 3-51 Locations for subsea rock pre- and post-supports in near shore area

3.8.2.6 Pipeline end manifold

The design of the pipeline end manifold (PLEM) will be detailed out in the FEED phase.
Basis for the design shall be that the PLEM is installed with the pipeline through the lay system on the vessel in order to avoid laydown of the pipeline and recovery to the vessel ship side for connection.

The PLEM will be equipped with a 12'' in-line full bore valve and a 6'' valve on the side of the PLEM for connection to the 6'' spool to the satellite well.

The PLEM will be laid down without the subsea pig receiver which shall be installed remotely at a later stage.

The PLEM will be protected by a protection cover and subsea rock will be installed around the edges to stabilise the protetion cover agains overtrawling.

The spool will be equipped with a 2'' low point valve drain system and a similar 2'' high point vent valve post/stab on the x-mas tree system will be included to ensure drainage of the spool during commissioning. Hence no such high point will be needed on the PLEM for drainage of the spool.

A relevant reference is the PLEM on a recent similar project based on a 10'' top entry valve and a 6'' side valve. This arrangement is shown in Figure 3-52. The footprint of the PLEM is 7m x 7m based on installation on a reel installation vessel.

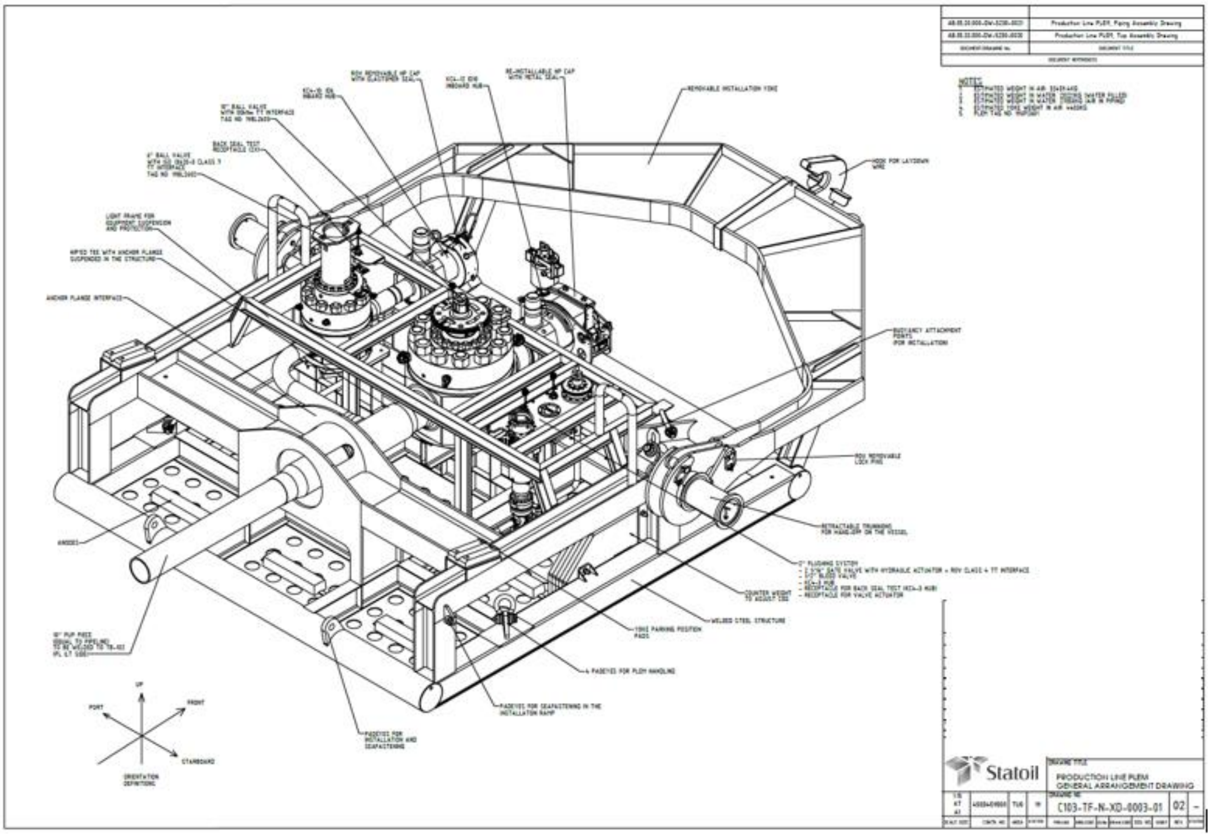


Figure 3-52 PLEM overview – reference project

The expected sized of the PLEM for the Northern Lights project can be stipulated based on the PLEM on the reference projects to be in the same range, ie a footprint of 7 m x 7 m and with a dry weight including the valves of approximately 34 Te dry and 30 Te submerged. The difference in design to the reference project is that the PLEM on Northern Lights needs a 12’’ pipeline and valve instead of a 10’’ valve and pipeline.

The PLEM will have the possibility to connect up a subsea temporary pig receiver to be used during the construction periode.

3.8.2.7 Pipeline construction and installation

Linepipe fabrication

For delivery of linepipe qualified suppliers are identified, previously used by Equinor.
The identified suppliers can deliver linepipe with the specification given, the minimum design temperatures and the quantities needed.

Coating

There are several possibilities with regards to coating of the linepipes. These can be coated close to the linepipe factories, underway during transport to Norway, or in Norway. The linepipes can either be coated by the linepipe suppliers, by the pipeline installation contractor or directly by Equinor. Several suppliers have been identified and have been previously used by Equinor.

Pipeline construction and installation

Several relevant installation contractors have been identified, both installation by reeling method and S-lay method. All have previously been used by Equinor.

Installation tolerances along the selected routes to be further matured in FEED have been defined by means of parallel profiles assessment. The normal lay tolerance (i.e. ±10.0m) has been applied along most of the pipeline route running to the injection site. A limitation (i.e. ±2.5m) to the laying corridor has been applied at the pipeline sections affected by subsea rock installation designed to mitigate pipeline overstressing or for crossing of existing facilities. This approach has been used for the centreline as well as the parallel profiles (i.e. ±5.0m and ±10.0m). Eventually, the laying corridor width has been optimized by merging the restrictions required for the centreline with the ones for the parallel profiles.

The four most critical sections are from roughly:

- KP6.0 to KP9.0
- from KP24.5 to KP27.0
- from KP29.0 to KP32.5
- from KP33.0 to KP35.0.

South of Fedje area

The rest of the pipeline route to Aurora injection site is affected by limitations to installation tolerances only at very few spot locations.

Preliminary installation analyses

- No issues are envisaged w.r.t. vessel capability in terms of maximum axial tension required to install the pipeline within integrity criteria. This conclusion applies to both reeling and S-lay methods.
- No warning has been identified in terms of main installation parameters requirements for both installation methods (reeling and S-Lay) and the selected route.
- Route curves stability is identified as critical in case of low values of maximum sagbend bending strain and pipe-soil friction factors. Curves stability check has to be further verified once pipe-soil friction factors evaluation is available vs installation scenarios. This implies that it is foreseen that restrictions to maximum sagbend bending strain will be imposed on the installation contractors.

Landfall and onshore pipeline

The landfall is planned to be a HDD tunnel with length approximately 650m as shown in Figure 3-53.

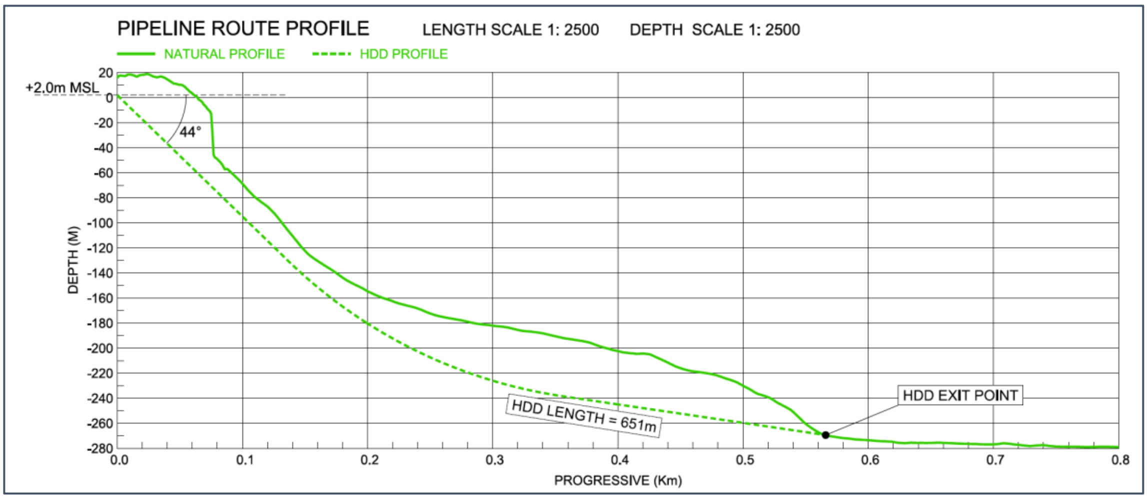


Figure 3-53 HDD tunnel profile

A pit approximately 10x5x4m (LxWxD) shall be drilled & blasted with the same slope as the borehole. The entrance wall shall be couture drilled perpendicular to the borehole angle.

Based on similar projects it is assumed that a standard 250-ton HDD rig will be selected for this operation. The rig will be modified to fit for the bore hole angle in the range of 45 deg. The geotechnical soil conditions and the length of the borehole will be challenging as regard steering according to the given profile. It is therefore planned for running the pilot drilling twice if needed. In case the first drilling will not be fit for purpose, the geotechnical and drilling performance date from this first attempt will be used to secure the success of the second drilling.

Based on pipeline stress analyses to be performed by pipeline engineering contractor, it will be concluded if an anchor / anchor flange will be required at the borehole entrance. Preparation for such an anchor block need to be done prior to pull-in.

The pipeline entrance pit shall be designed for future installation of a seawater circulation system to avoid freezing inside the HDD in case of low product temperature.

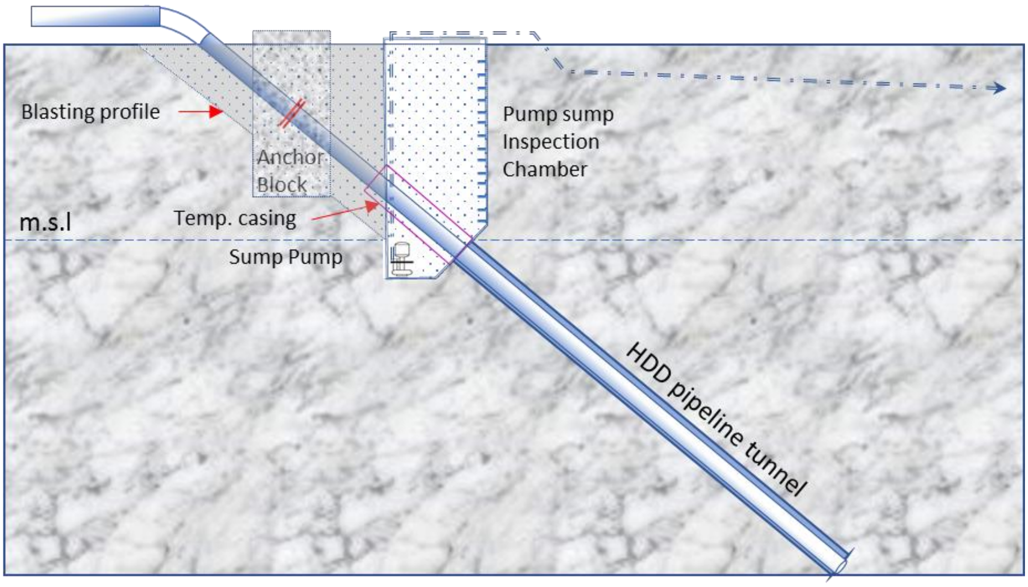


Figure 3-54 HDD tunnel exit pit design (for illustration only)

3.8.2.8 Pipeline commissioning

Pigging shall be performed from the terminal temporary pig launcher.

The subsea pig receiver shall be able to receive pigs during:

- Cleaning and gauging operations
- Dewatering operations
- Nitrogen filling / CO_2 filling operations (to be confirmed)

The subsea pig receiver and launcher shall only be used during the temporary commissioning phase and will not be designed for the operational phase as there is no plan for any regular inspection pigging during operations.

<u>Pre-commissioning</u>
The pipeline will be free-flooded after pipeline installation with raw seawater via the PLEM. The acceptance criteria shall be that the pipeline is filled with raw seawater without sea deposits.

The pipeline shall further be cleaned and gauged with pigs to prepare for tie-in of the spool, to remove any entrapped air, remove any dirt and ferrous debris left in pipeline, and perform internal diameter (ID) check after installation. The free-flooding, cleaning and gauging operations are planned to be performed by the pipeline installation contractor.

<u>System pressure test</u>
The purpose of system pressure test is to check for gross error and leak tightness of pipeline and connections prior to start-up.

Following cleaning, gauging and tie-in of spool to the satellite and connection to the onshore pipeline/onshore terminal, and installation of High-Pressure Cap at both ends of pipeline, the entire pipeline including the 6’’ spool between the

Subsea Structures will be subject to a system pressure test in accordance with requirements in DNVGL-ST-F101, injecting treated freshwater from onshore site.

An ROV is planned to be used to perform visual inspection of the subsea connections/Subsea Structures during the hold period. The pipeline to be depressurized at onshore site. If the 6'' spool is not to be incorporated in the System Pressure Test a separate leak test of the 6'' spool needs to be carried out.

Dewatering

The purpose of dewatering is to remove as much liquid water as practical from pipeline to minimize the drying time and prepare the pipeline for drying and product filling. Due to particular corrosion issues associated with CO_2 and water, the CO_2 pipeline shall be dried to a sufficient dew point (typically -45 ^{0}C) before filling with the CO_2 stream.

Following the subsea pipeline test a dewatering pig train of bi-directional pigs, each with an isotope, to be launched from onshore pig launcher to pig receiver on the pipeline end manifold (PLEM) with Nitrogen as propellant force. There will be freshwater batch (between 1st and 2nd pig launched) to wash out/dilute chlorides/salt deposits on the internal pipeline wall and the 6'' spool between the Subsea Structures. The next pigs will be separated by batches of MEG to remove water and to dry the pipeline.

Performed calculations indicate as follows: 1) chloride content will be far below 200ppm, and 2) in the Nitrogen phase after arrival of last pig into pig receiver water content is around 3 ppm corresponding to a water dew point of about -48 °C at 35 bara. It means that a subsequent and separate drying operation of the pipeline should not be required. Following completed dewatering operation, the pipeline would be ready for CO_2 Filling.

MEG and Nitrogen to be provided from a temporary spread on onshore facilities.

3.8.2.9 Pipeline operation

Product filling with CO_2

Following the dewatering operation, the pipeline will be left with nitrogen, chloride content < 200ppm, and dew point -48 ^{0}C according to Equinor specifications.

As the CO_2 flow fill the pipeline pressurized N_2 will be discharged from pipeline at subsea end. It has been advised that N_2 shall not be injected into the well/reservoir (will affect the injectivity). Hence the N_2 shall be discharged from the PLEM to sea before arrival of the CO_2 flow. Further work will be performed in the FEED phase to detail out this program. The discharge arrangement on the PLEM will have to be designed such that no ingress of seawater will take place during discharge.

Inspection, monitoring and testing during operations

There are many different corrosion mechanisms and credible threats to the integrity of pipelines. These are determined from material used for the pipeline and analysis of the carried fluid. The basis for a safe and reliable operation of a CO_2 pipeline is the Integrity management system described in Equinor internal requirements, DNVGL-RP-F104 Design and operation of carbon dioxide pipelines and DNVGL-RP-F116, Integrity management of submarine pipeline systems.

Generally, a baseline inspection to assess the condition of a new pipeline is recommended in the first operational year from a pipeline operation view. This is not a mandatory requirement and can be avoided if mitigating measures are implemented. To meet this requirement all threats to the pipeline regarding elements like H2O, H2S, customer specific elements etc. must be identified and analyzed to assess the impact on the pipelines integrity. A system to monitor the quality of the fluid will be established, and mitigating action taken according to approved procedures.

The internal evaluation in Equinor's pipeline operations department based on available information about design and known possible treats revealed no major reason to perform a baseline pipeline inspection or to plan for inspection pigging. A prerequisite for this conclusion is to establish an acceptable integrity management system. It is strongly recommended that as part of the integrity management system online monitoring of the fluid composition in established to assess production data for calculation of corrosion rates.

If an internal inspection or cleaning for any reason after production has started is required, must a dedicated project must be mobilized for prepare and perform the operation. This usual involve a pig train containing inspection and cleaning pigs. The driving medium is liquid CO_2 using the pump capacity on the plant. The operation has possible issues to be identified regarding risks due to receiving pigs subsea, use of vessel and flow assurance. It has been confirmed by a potential vendor that they can provide an inspection tool that can run in a pipeline containing CO_2 in liquid phase. The use of the tool is based on MFL technology (Magnetic Flux Leakage Probe). It is also confirmed from a potential vendor that they can deliver PU pig disks suitable for CO_2 in temperature interval +100 to -20C.

An Integrity management system will be established according to Risk Based Inspection requirements in Equinor and principles such as the Integrity Management System as illustrated in Figure 3-55.

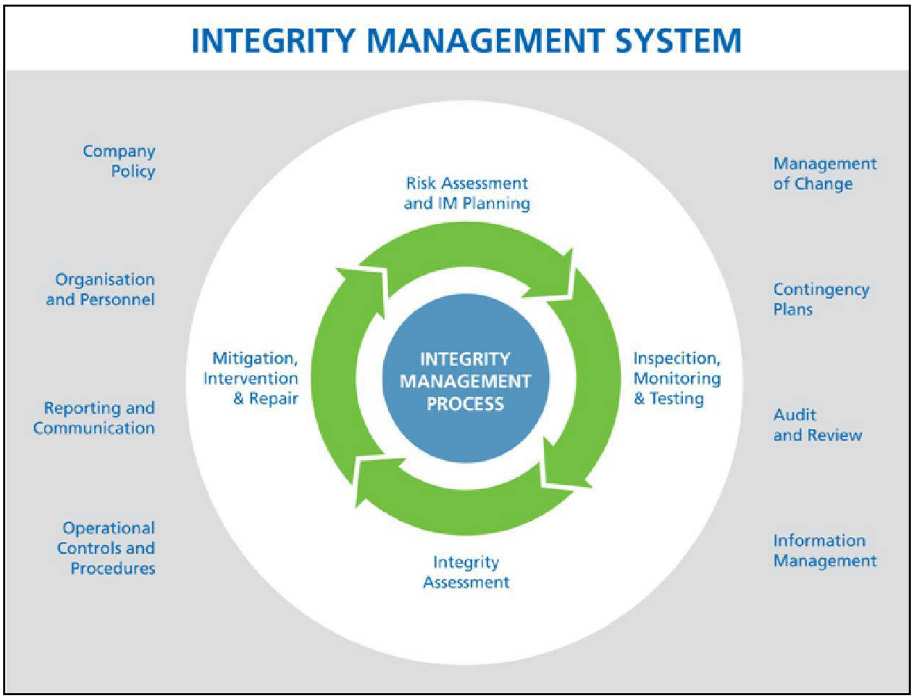


Figure 3-55 Integrity Management System

Failure mechanisms for a rigid pipeline system shall be assessed and selected based on Equinor requirements and operation experience from other pipelines. Integrity management for CO_2 pipelines are regarding external structural threats, almost like a hydrocarbon pipeline. The main difference for the operation part is that there is a short cold zone instead of a hot and the consequence of a leak is different.

When the RBI system is established, and the as-laid survey is completed, is the next step to evaluate the pipeline condition and define an inspection program. The pipeline will be divided into sections depending on threats. Table 3-13 shows some relevant threats.

Table 3-13 Pipeline relevant threats during operation

Structural threats	Buckling, fatigue, free spans, damage etc.
Third party threats	Trawling, anchoring, falling objects etc.
Environmental loads/threats	Erosion, current, landslides, geo hazards etc.
Corrosion assessment	Anode consumption, bare metal etc.

Not later than one year after start-up of the production an external inspection offshore shall be carried out as specified in Equinors internal requirements to verify the configuration assumed in design. Result from this inspection will be applied to calculate a probability of failure for each section to determine an inspection interval. Usually annually in the first three year in production and then a fixed interval. The Probability of failure for each section will be accumulated to an overall probability of failure for the pipeline. A final condition report and long-term inspection forecast including budgets will be prepared and delivered to the owners.

3.8.2.10 Flow measurement, leak detection and monitoring

If a leak occurs on the pipeline the leak duration and dispersion may be limited with use leak detection resulting in shut down of the source or landfall emergency shut down valve. The time for detection will depend on the size of the leakage. The leak source can be closed after a short period for large leakages however it might take a long time before small leakages is discovered.

<u>Full rupture</u>
Simulations shows that full rapture of the pipeline will result in extremely high flowrates from the onshore facility if the pressure remains at controller setpoint of 45bar.This will happen short time (seconds) after the leak is initiated. This flowrate is expected to result in a pump limitation resulting in an automatic shutdown. The pump limitations will be further analyzed by process discipline in the next phase of the project.
Based on this an instant shutdown of source is assumed for full pipeline rupture cases.

<u>Medium to small leakages</u>

Possible ways to discover medium leakages on the pipeline system is:
- The estimated export of flow from the tanks (level decrease) is too large compared to the flowrate into the well. Operator response or automatic system based on online measurements of tank volume.
- The flowrate from the pump is too large and the pump will not manage to remain a pressure of 45bar at the pipeline inlet, this will result in lower pressure (PALL) and initiate an automatic shutdown.
- The onshore tanks will get empty much earlier than anticipated. (dependent on operator awareness)
- Mass balance system; requires input from flow measurement at both ends of the pipeline.

A mass balance system will be more robust for leak detection. However, the need for such a system will depend on the outcome of safety risk analysis studying the consequence of a pipeline leakage without discovery and onshore shutdown. A mass balance system based on flow measurements at both ends will most probably be very accurate and result in a leak alarm within minutes even with a small leakage (20mm hole). This is due to liquid filed pipeline and consequently a stable pipeline inventory.

Leak detection during a shut down
During an injection shut-in period, the pipeline volume can be isolated, and pressure monitored to detect a possible leak. This requires a pressure gauge downstream of the onshore isolation valve and pressure gauge at the subsea system. This method should be able to detect small leakages that otherwise would not be detected before inspection surveys with ROV.

Monitoring of water content and CO_2 stream properties
Continuous monitoring of water content upstream the pipeline will provide data for pipeline integrity assessments and potentially reduce the requirements for inspection pigging. A technology assessment for the continuous monitoring of water in liquid CO_2 will be required, as detailed in chapter 6.1.

3.8.3 Onshore

3.8.3.1 General

The Onshore Facilities at Naturgassparken are:

- Import Jetty for offloading and handling of CO_2 from ship
- Equipment for transfer of Liquid CO_2 from the jetty to the onshore storage vessels
- Vessels for storage of CO_2
- Process systems to process the Liquid CO_2 from storage conditions to pipeline injection conditions
- Metering and quality measuring systems for CO_2
- Utility systems
- Substation
- Administration complex including an administration building with visitor centre, control room and other features, as well as a Workshop building comprising a laboratory.

The capacity for the Onshore Facilities is export of 1.5Mt/y of Liquid CO_2. Based on receipt of CO_2 from two capture sites the expected yearly volume will be in the area between 0.4 and 0.8Mt/y.

The ship sizes assume for the Onshore Facilities are 7,500m3, with a frequency of ship arrivals every fourth day for receipt of CO_2. The jetty design is based on a ship length of 130 meters.

The design life for the Onshore Facilities are:

- Onshore facility equipment design life shall be minimum 25 years
- Civil and structures shall be designed for a lifetime of 50 years

Constructability considerations have been incorporated into the piping and layout studies, with a strong focus on the transportation and installation of the CO_2 storage vessels. Further evaluation is expected during FEED.

3.8.3.2 System description

The onshore plant provides a part of the transport chain, with holding capacity to facilitate a reasonable logistic performance to allow for some of the unforeseen factors like weather and delay and utilising the flexibility in injection rates.

The liquefied CO_2 will be transferred to the transport ship at given battery limit condition defined by GasNova. No cooling or reliquefication will take place neither in the ship nor at the onshore intermediate storage plant. This will imply some heat ingress into the system, and consequently some increase in equilibrium pressure, hence some higher design pressure applies for the systems than what is specified at the capture sites.

The main assumption for the development of the onshore storage plant is a principle with low manning and presence of the works force during daytime only. This will lead to a high degree of automation and will also dictate some requirements for monitoring. There will be a local control room in the administration building and the central control room with 24/7 manning will be co-located with other Equinor operations

The design shall to the extent possible be based on land-based industry standard, not an oil and gas environment.

Import / Offloading

Offloading from the ship to the storage tanks is performed by internal ship pump, which is powered from onshore during offloading. The offloading design rate is 800t/h.

During offloading, the pressure will fall in the ship tanks. Similarly, the pressure will start rising in the onshore tanks as they are being filled, due to compression of the gas present. An equilibrium vent line between the onshore tank farm and the ship will ensure return of the gas to the ship and hence no emissions.

The connection between the transport ship and the onshore piping system will as a base case at concept select be one loading arm for off-loading of liquid CO_2 and one loading arm for return of CO_2 gas. One additional loading arm will be common spare for these two services. They will be equipped to ensure that the emissions due to start up and cool down of the piping systems is kept to a minimum.

Intermediate Storage

The overall size of the onshore tank farm is dictated by:

- Size of ship to ensure that the tank farm has capacity to accommodate the transferable volume
- Range between maximum and minimum injection rates, which defines flexibility in the operation of the tank farm.
- The location of the jetty and expected availability due to weather constraints.

It is important to match the holding time in the tanks with the operational requirements, to limit heat ingress and thereby pressure build up.

Conditioning and injection

The system export includes pumping and heating, with the following design criteria:

- The exported CO_2 shall always be one phase liquid.
- Export temperature shall be above 1°C. This requirement is being challenged, as it requires heating that will be further investigated during FEED.

- Pumping capacity of upto 171t/h, with an export pressure that is always above 45barg to ensure no flashing takes place.

Metering
The metering philosophy is described in section 3.5.

Utilities
Number of utility systems has been kept to a minimum:
- Compressed air and instrument air.
- Inert gas will be supplied either as heated CO_2 or as Nitrogen generated through a nitrogen generator as needed. To be concluded in FEED and therefore currently included in the cost estimates.

The following decisions have been made to reduce the number of utilities:
- Fuelling of ships will take place off-site, hence no hydrocarbon sources in place.
- Fresh water will be supplied from the municipal supply to the administration building and the jetty, therefore no fresh water system or storage tanks present other than one supply line.
- No effluent treatment nor active drainage / surface water treatment will be needed as no sources for external pollution of surface water is present. Equipment requiring oil cooling or grease for lubrication will be located within bunds to ensure any spillage can be collected and transported off site.
- No hydraulic systems included, relevant actuated valves will be operated electrically.

Power supply
Power will be supplied by the local energy company BKK at 22kV and an approximate duty of up to 10MW.

For the heating of the liquid CO_2 prior to entering the pipeline, several solutions have been looked into to optimise energy consumption:

- Utilising heat from ambient air

Due to the temperatures of the CO_2 and the foreseen challenges with freezing due to the very cold surfaces, there will be a need for substantial maintenance that appears non-optimized, it is considered that a parallel heating source would be required in addition during the cold seasons.

- Utilising heat from seawater

A seawater-based system for heating of the liquid CO_2 prior to export has also been looked into. This will require an additional closed fresh water loop with MEG or TEG to avoid build up and plugging of equipment. This is a costly and maintenance intensive solution and has not been elaborated further.

- Reduce heating of the CO_2 prior to export.

This solution is subject to a feasibility assessment as a system for circulation of seawater through the HDD channel to ensure it does not freeze. Such a system is novel, work is ongoing to search for reference cases and to assess if the circulation can be implemented at a reasonable cost. However, this solution will need a fallback should the HDD tunnel start to freeze; therefore, the base case heaters have been retained to ensure CO_2 conditioning prior to export. This solution will most likely require a technical qualification programme.

Venting and sources for emissions

At steady state/normal production the overall CO_2 gas balance will be that CO_2 gas must be created by a vaporizer to replace the volumes of liquid CO_2 injected from the storage tanks.
When CO_2 is off-loaded from the ship, there will be a balance via the vapour return line between the tank farm and the ship resulting in no additional emissions.

In a situation where the onshore systems are prepared for offloading, resulting in some flashing of CO_2 due to cooldown of piping, and there is no injection of CO_2, there will be some excess CO_2 that will be vented off.

In the situation when the total plant is shut off with no injection for several days, there will be some heat ingress, resulting in pressure build up in the storage tank, and eventually some venting if the duration is sufficiently long. This is considered being a rare case and will be avoided to the extent possible as this may also be detrimental for the injection well performance.

3.8.3.3 Layout

The major equipment items are the storage tanks for CO_2. Both horizontal and vertical storage tanks were considered, and to limit the area required for storage tanks and cost for area/site preparations vertical storage tanks were selected.

A plot plan has been developed for the onshore facilities, and the layout shows an extension for a Phase 2 that can be included within the area of Naturgassparken.

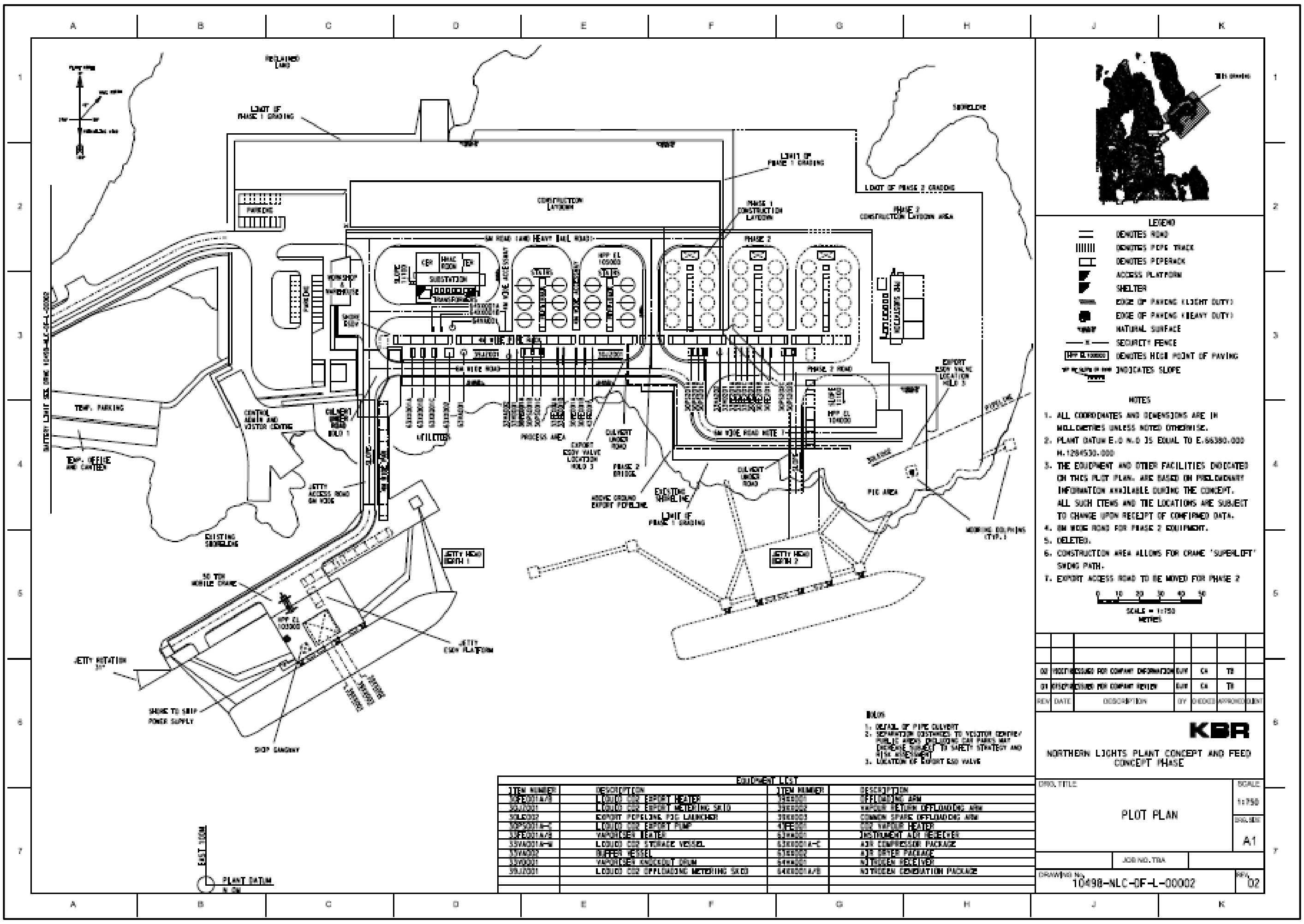


Figure 3-56 Plot plan

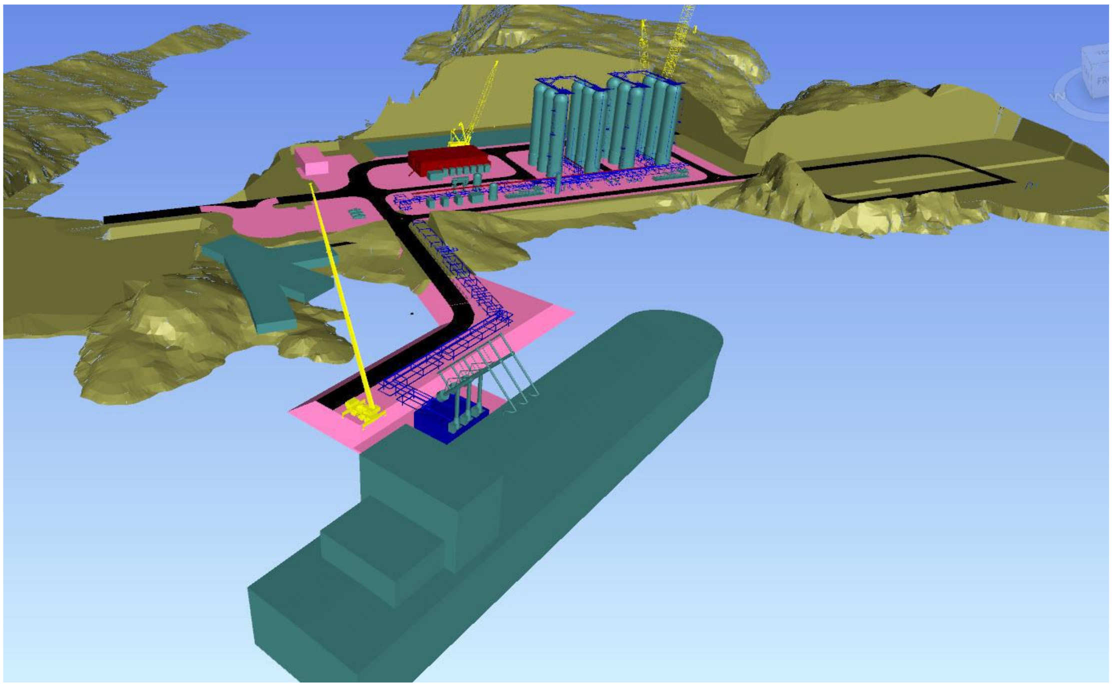


Figure 3-57 PDMS 3D model

3.8.3.4 Storage Tanks

The storage facility shall be able to store the volume of CO_2 delivered by a ship and in addition provide a minimum over capacity. This over-capacity is not specified and will result from the selected dimensions of the vessels. A separate study was performed by the concept contractor KBR/Granherne looking at various types of design, orientation and tank size and storage volumes for the onshore facility. A selection was made based on minimizing overall CAPEX through a philosophy of utilizing offsite fabrication; limiting layout requirements; as well as optimizing the volume vs. weight ratio to reduce the amount of steel required per tank. The current design consists of 12 cylindrical, vertical tanks with an inner diameter of 6.25 m and a tan-tan height of 25m giving an overall capacity of approximately 9,150 m3. This provides a 22% overcapacity compared to the current ship size of 7,500m^3.

This flexibility is provided in case of any upsets in the delivery chain, i.e. issues with delivery of CO_2 or issues with injection of CO_2. A full stop in injection due to empty tanks will have a disadvantage for well behaviour reasons. Based on the design pressure and temperature the project has sought to maximise the volume of the individual tank while avoiding the requirement for Post-Weld Heat Treatment (PWHT), as per industry standard EN 13445, as this is seen to increase cost as well as limit the number of potential suppliers.

Following the change in the design basis of the required ship size the number of storage tanks at the onshore facility has been reduced from 16 to 12. It is the combination of these 12 storage tanks in the maximum allowable size (as per boundaries above) which give an overall capacity of approximately 9,150m^3 and a subsequent buffer capacity of 22%. Further, some of this volume is expected to be required as working volume to obtain stable control of the process. This buffer capacity can be reduced but may then have an impact on the availability of the onshore facilities. Considering there is no availability target for the receiving terminal for handling of CO_2 in the Gassnova design basis the project has opted for a flexible design with regards to optimisation when entering FEED, where the aim is to further mature the overall design, i.e. assess the impact of reducing the overall storage volume closer to the ship volumes.

An indicative sketch of a single tank is shown in Figure 3-58.

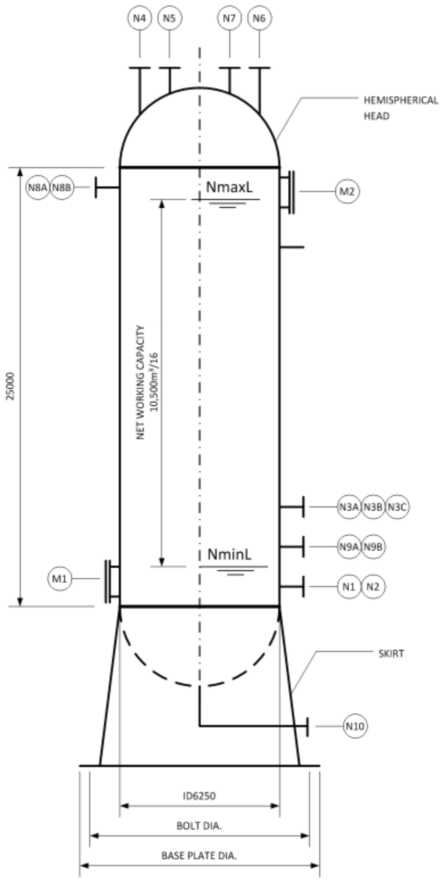
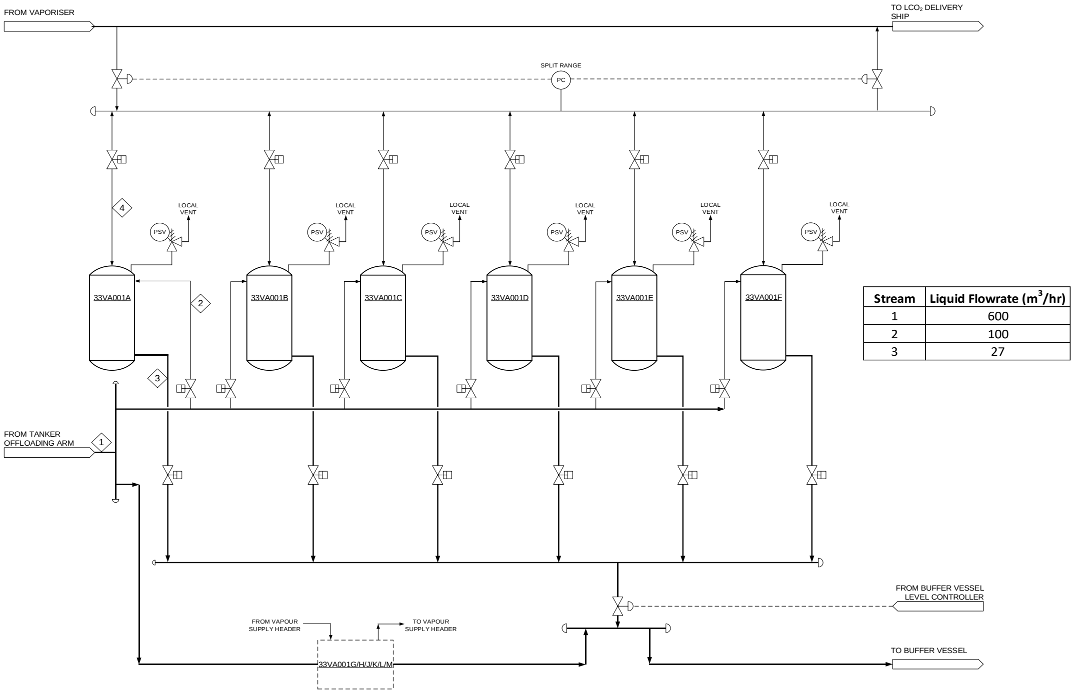


Figure 3-58 Vertical vessel illustration

The storage tanks have a design pressure of 22barg and steel grade as per EN 10028-3. The size and design of the storage tanks is selected to avoid code post-weld heat treatment (i.e. keep the maximum thickness at welded joint below 35mm for the thicker part) to reduce cost and maximise possible vendors.

The storage tanks will be grouped together in two clusters of six tanks to be able to fill one cluster from the ship while simultaneously producing (injecting) from the other tank clusters.

To maintain pressure equilibrium while loading or unloading the storage tanks a vapour header allows flowback of CO_2 vapour from the storage tanks to the ship. Additionally, a vaporizer is required to supply CO_2 gas to maintain pressure while unloading the storage tanks during injection. The set-up of this system is shown in Figure 3-59, which is taken from one of the process flow diagrams developed by KBR/Granherne.



Stream	Liquid Flowrate (m^3/hr)
1	600
2	100
3	27

Figure 3-59 LCO_2 Storage Vessels Configuration

3.8.3.5 Site Preparation

Site preparation is performed in order to establish a robust basis for installation of equipment and other features at the plant. The terminal area will be located on bedrock and levelled by rock blasting and filling.

The rock blasting level will be minimum 1.2m below final grade which is at elevation +5,0. The layer between the rock blasting level and the site preparation level will be filled with crushed rock of grade 0/300mm and compacted. This layer will work as storm water drainage and for routing of infrastructure in trenches.

3.8.3.6 Jetty

The access road to the Import jetty will be a rock fill with materials from the site preparation blasting, covered with armour blocks as wave protection. Existing sediments shall be dredged and deposited.

The jetty head is 38m long with an elevation +3.00m for the top of slab. It is designed as a concrete slab/beam structure founded on concrete filled steel piles with pile shoes which are driven into the bedrock. The front of the jetty head shall have two fenders to absorb impact from berthing ships and ensure proper behaviour in all conditions when berthed.

The walkways to the mooring points are steel truss structures with gratings, also founded on concrete filled steel piles. The layout of the gangways between the jetty head and the mooring dolphins is made to facilitate berthing without the support of tugs.

The minimum required water depth for the calling vessels are 10.5m (draft 8.5m + 2.0m clearance)

The location of the import jetty is chosen based on the required water depth, metocean conditions, and in order to facilitate a future Jetty no. 2. Due consideration is also made for the operations of the existing jetty at Naturgassparken.

The metocean conditions such as waves and current are assumed to be favourable for the import jetty, and the regularity is expected to be very good even through the winter months. A future Jetty no. 2 will be more exposed to wind, waves and current, which will affect the regularity.

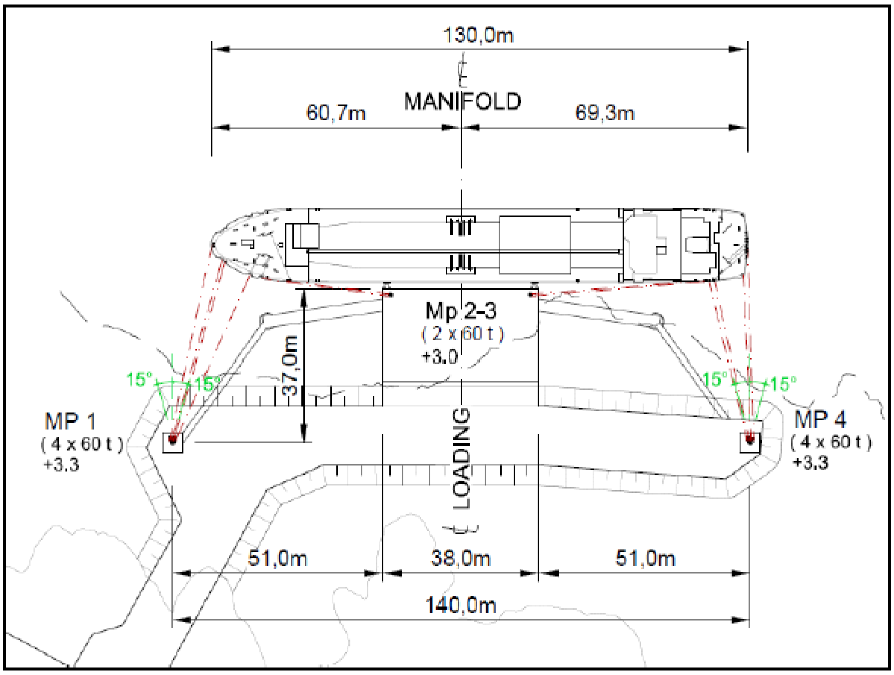


Figure 3-60 Import jetty layout

3.8.3.7 Administration complex including visitor centre

The Administration complex comprises an Administration building and a Workshop building.

<u>Administration building</u>
The concept for the Administration Building with its contemporary architectural expression is based on local traditions, materials and colours. It is located at the south-west corner of the site, next to the entrance and parking area. The building's gross area is about 1,800m^2 and has two main functions - an easily accessible public area and a segregated administration area.

The building has one main floor which is staggered by 2 metres from the reception and up to the main area. This height difference ensures that the main area has an elevation +7.00 and therefore safer in the event of a CO_2 emissions.
The need to segregate the administrational function in a secured area and a public function as a presentation centre for the Northern Lights project, is one of the main issues which affected the buildings layout and form.

The public area comprises wardrobes, canteen and an auditorium. The canteen and the auditorium can host up to 60 visitors, and both are located to ensure a good view of the natural surroundings as well as of the jetty and the plant.

The administration area is for the employees who operate the site. It has a control room, office space and meeting facilities for about 15 persons.

Both areas have the necessary toilet and changing room facilities.

Figure 3-61 Visualisation of Administration building and Workshop building

Workshop building

The storage and workshop building is the result of the necessity for such functions as a workshop and a laboratory with direct access to the main site. By placing these functions in a separate building, it allows the Administration building to focus on visitor groups and administrative tasks. With direct access to the site from the Workshop building, it simplifies the logistics for work which should be executed in the laboratory.

The Workshop building is located north of the main gate. The building is integrated as part of the perimeter security boundary.

This building is not open to the public and comprises of 1 floor and has a gross area of 200m^2 and contains a laboratory facility, a small workshop for tools, and office space for maximum 3 people. The building is designed with flexibility for future extensions.

Figure 3-62 View of the site with the Import jetty and the Administration complex after performance of site preparation.

3.8.4 Ship transport

The concept for ship transport is to use ships that closely resemble LPG ships. This is expected to be the best concept to maximise the ripple effect in constructing a new market for trade in CO_2. This should naturally lead to future development of the concept in the full-scale demonstration project, allowing for further development of ship types, scaling and possible conversions opportunities.

The Shipping Logistics studies[6] show for demonstration project volumes, a ship type that closely correlates to Fully Pressurised LPG ships would fit the technical requirements well. Further, existing knowledge in shipping of Liquid CO_2 in the small-scale food grade industry, acts a conduit for knowledge sharing, demonstration of scaling and proof of concept. This, along with a need to fully de-risk future operations when operating close to the triple point of CO_2, in a lower-pressure carriage regime, point to the chosen operating conditions of 15barg as being correct.

It should however, be noted that if transportation volumes increase, or are envisaged above 7,500m^3, then a lower-pressure carriage condition may need to be further considered, largely to gain greater economies of scale. Even with the use of High Tensile Steel C-Type tanks, there is a limit on diameter of tanks that can be manufactured; there is also an upper limit on a ‘standard’ ship hull available without drastically changing the manufacturing profile of likely ship building yards.

The Northern Lights project has continued Research & Development contribution to studies exploring the use of a lower pressure carriage condition for future volumes. In this frame of reference, it is true to say the logistics study was key in

[6] see document RE-PM673-00029_01 Logistics study – Base Case 2.0 – issued 4th May 2018

the selection of the carriage conditions, as it demonstrated for the scale of this project there was no clear cost driver for the ship volumes required that triggers a need requiring alternative carriage conditions to those seen as 'standard' for the smaller food industry vessels in service. The study showed for the volumes and sailing patterns in the demonstration phase – if assessing a conventional LPG shipping project – the choice is clearly between a Full Pressurised (FP) or Semi-Refrigerated (SR) vessel type.

Table 3-14 Vessel type and carriage conditions

Typical LPG Vessel Type	Comparable Carriage Conditions
Fully pressurized	Medium pressure
Semi-refrigerated	Low pressure

This choice between vessel types translates to a Medium-Pressure or Low-Pressure carriage, when discussing carriage of LCO_2. It's also important to consider how the shipping industry generally operates, i.e. to use standard ship types compatible with as many sites as possible. Shipyards can therefore offer relatively standard products without the need for detailed engineering for each contract, and as a result can offer competitive fixed priced contracts. It follows that for any deviation from 'standard' there will likely be a premium to pay.

Figure 3-63 Illustration of LCO_2 ship

A first choice to make is between FP or SR ship types. Market data indicates that both ship types are possible in the required capacity range. However, the SR type will generally have a premium of 40%, largely due to increased machinery for refrigeration. This premium, at a Class C estimation level, equates to around 10MUSD for the base case vessel type, but brings more risks as the required lower pressure carriage has not been executed or studied in detail.

There is existing proven experience at the higher pressure carriage condition, and perceived technical risks when operating closer to the triple point at a lower-pressure carriage condition. Screening level studies show relatively high costs for niche ship designs. A low-risk path to scaling up the current shipping model is to maintain the current proven carriage conditions, keeping deviations from standard as low as possible and de-risk those areas within the project, before engaging the potential shipbuilding market. The strategy to demonstrate that associated technical risk is low and communicated with potential contractors remains key in this value proposition and explained later in this summary.

The ship transport scope was formally added to the of the Northern Lights project scope in November 2017, as Equinor previously had control of the intermediate land-based storage and injection via pipeline to a target subsea storage location, only. Therefore, direct injection from a ship has not been discussed in this chapter, nor falls into the scope of the current project, but is continuing to be de-risked via R&D activities.

The overall concept can be described as collection of CO_2 in liquid form, via ship from two different capture sites, at an agreed specification (assumed to be considered as 'clean' in the IGC code definition). These capture sites are in the general vicinity of the Oslo Fjord, and CO_2 is captured and stored at the sites, via industrial process. For Total, Shell and Equinor, this venture is a different scenario compared with other proven CCS methods, within the hydro-carbon business scope, as the capture locations range from waste recycling plants to cement factories. This industrial capture plays a large part in proving that the technical & commercial model chosen for the demonstration project and adds weight to the need to prove commercialisation of the business model. As part of the demonstration new ship construction and showing the most likely ship type from the start of the project is an important factor, and shipping is seen as a key enabler for commercial & technical flexibility of the business in this sense. This doesn't exclude the possibility of future conversion from various ships and will also hopefully encourage speculative owners and yards to consider CO_2 as a possible cargo in future multi-gas vessel.

It is envisaged that a multi-gas ship will be used from the start of the project to mitigate potential start-up risk, this is considered a neutral cost, as conservative shipyards would prefer to offer a 'standard' LPG ship, modified to carry LCO_2, with no additional investment to alternate between LPG & LCO_2 grades on a regular basis.

Figure 3-64 Illustration of LCO_2 carrier

Screening has shown conventional fully pressurised LPG ships can be constructed to allow Liquid CO_2 carriage. This will involve a change of material in construction of the ship tanks and consideration given to specialist materials (e.g. High Tensile Steels). A technical file was developed in the concept select phase and via engagement with Classification Societies (DNVGL, LR and BV), showed a concept to use 2.5% Ni Steel tanks in the ship construction was credible. During concept select phase the potential deviations from the IGC code, to use Higher Tensile steel with thicker tank walls was further de-risked, via a DNVGL Approval in Principle study – demonstrating that an equivalent standard (EN 10028-6) can be used and accepted by the Flag state as signatory to the IGC. It should be noted that no other equivalency route deviations are considered necessary for the design, thus all other requirements from the IGC Code, IACS rules and Flag-state requirements will be followed.

There is further need to 'Qualify' the use of this material and concept during FEED, a summery is included here, more detail is available in section 6.2. This involves qualification of material suppliers, and potential tank manufacturing sites ahead of pre-engaging targeted shipbuilding market leaders in China, Korea and Japan. A clear assessment of construction methodology, welding techniques, controls and acceptance criteria will also be delivered in the FEED report. These will likely require audits and additional testing at sites other than the shipyards, and competent oversight from Owner and Charterer representatives in addition to Classification and Shipyard QA teams at those additional sites.

The main areas of concern when using P690QL2 (the identified tank material for LCO_2) centre around controls re welding, post weld treatment and fatigue resistance. In the FEED phase the project team will work towards collecting material data from potential suppliers, develop approved material data sheets defining qualifications, requirements and testing scope, pre-qualifying tank fabrication yards using HSQE analysis (including welding, welding certification, NDE and PWHT procedures) and verifying fracture mechanics and fatigue analysis via testing to confirm the operating pressure.

A decision has been made to build flexibility into the construction and contracting strategy for shipping (absorbing risk re uncertainty regarding uncertainty of the number and phasing of the capture plants), by selecting to build two new vessels for CO_2 carriage at maximum capacity of 7,500m^3. An optional 'Plus 1' could bring the total number of ships to three and will be verified during FEED. Logistics studies verified two larger ships as a preference. There is a need to commercialise the project as early as possible, and be scalable, this requires Flexibility. All adding weight to this decision process as flexibility is a key enabler/differentiator of the project, and shipping, in the form of increased capacity is a driver to restrict niche optimisation for the demonstration project only, with relatively low perceived marginal gains.

The general flow of technical work in the FEED Phase can be described as follows:

- Prove concept for High Tensile Steel Tanks for ships, close gaps identified in Approval in Principle documentation and engage class in General Approval for Ship Application (GASA) the next step of the process.
- Verify TRL4 technology qualification for tank construction material, within Equinor system. Basis is 7,000m3 LPG vessel 'Oscar Niemeyer' whose C-type tanks are constructed with S690QL steel for use at 18bar and -10°C.
- Conduct Mini-FEED studies to verify critical items from concept select phase –The key target areas for this work include: CO_2 specific operational items (purge, drain, vent, surge control, sampling, filling limits, gas detection) that differ from conventional LPG maritime practice, key design technology development areas for CO_2 that differ from traditional LPG service (MLAs, hoses, radar gauges, filling limits, metering) and project specific items including battery design and specific interface requirements (manifold sizing, shore power size and configuration, storing/sparing, waste disposal, mooring, emergency services/systems, autonomy, surge control etc).

- Additional Studies with classification societies (Alternative Risk Based Design or specific studies using DNV-RP-A203 etc) adding weight to internal studies in technical engagement process.
- Consideration to developing ‘green’ technology could also be considered as part of the overall CO_2 intensity reduction philosophy (alternative fuelling, onboard CO_2 capture technology, air lubrication, etc.)
- Verify supplier’s ability to produce Type-C tanks to the identified specifications
- Identify Ship Owners with capability of operating vessels on behalf of Northern Lights
- Develop ITT Documentation in parallel with FEED Report

Cost benefit analysis of specific items incorporated within the proposed Outline Specification[7] and Procurement Strategy for Shipping[8] have been requested from Gassnova. They are outlined below for reference:

Ship speed

The current conceptual design for a 7,500m^3 LCO_2 carrier has a Wärtsilä 10V31DF engine system with rated power of 5,500 kW and a guide cost of 404 EUR/kW. This gives the vessel a speed of 14knots delivering 85% of its Maximum Continuous Rating, with 15% Sea Margin and 500kW output to the shaft alternator.

If the project selects an 8V31DF engine with 4,400kW then for the same conditions the expected speed will be 13.2knots. In this case the project guide shows an installed power cost of 449 EUR/kW.

From the above descriptions a cost saving of around 200,000 EUR is possible if we move from 14knots service speed to 13.2knots service speed. However, with the additional flexibility the speed brings to the scheduling, coupled with the fact that normal best practice operation at reduced power has a positive effect on fuel consumption, show this to be a negligible saving. Therefore, the recommendation is to specify service speed of 14knots, as verified by the logistics study.

Recommendation: Base case 14 kts as ship speed

Capacity

Ship capacity has been developed based on logistcs studies in the concept phase based on scenarios for a number of capture plants (and more). The current basis is two capture plants loading 5400m^3 every 4 days. In order to bring down the cost of ships from the initially proposed special designs, the strategy selected was to adopt ship designs that closely resemble existing designs, namely fully pressurised LPG type ships.

Two key drivers are:
- Provide efficiency gains for future projects thourgh learning and scaleability effects
- Establish markets and develop suppliers

The project recommeds to maintain 7500m^3 ship volume as a basis for further maturation. This is based on:
1) This ship size is the largest envisaged for MP transport conditions and hence could be considered a standard for future market development into the Norwegian infrastructure. Then the next wave of ships would be subject to sigificant learning curve benefits if kept unmodified. This ensures lowest possible entry cost for new suppliers of CO_2 and enables future builds to come online earlier, bringing commercial volumes earlier to market.
2) The ship size offers operational flexibility in the Norwegian Demonstration Project. In case of unplanned outage of one ship, the selected ship size offers the opportunity to maintain a “milking route” funtionality for some period

[7] See RE-PM673-00014_01 Outline Specification for 7,500m^3 pressurised LPG & Liquid CO_2 Tanker – issued 23rd July 2018
[8] See RE-PM673-00040_01 Procurement Strategy for Shipping issued 31st August 2018

to prevent a full stop to a capture plant. A marginally designed ship would require very high uptime and have no ability to cater for unplanned events. It is also a potential upside in reducing capture plant storage tank volumes that will be studied further in the FEED phase.

3) The ship size also offers low cost entry to the Norwegian infrastructure for new suppliers in Norway (and elsewhere inside an approximate 400NM radius) without adding more ships.
4) Larger ship capacity is envisaged to maintain interest from the market for (initially) a modest fleet volume.

Recommendation: Maintain 7,500m^3 capacity for shipping

Hybrid option

High Level Screening of the cost to install batteries for 30 minutes prior to berthing and 30 minutes after departure, along with other design basis requirements (shore power charging, LNG primary fuel, PTO/PTI, OPEX considerations etc..) showed that there was indeed an overall benefit to installing and operating hybrid option system with batteries. This is in the region of 10% overall fuel saving, including provision for CO_2 tax regimes in Norway, but excluding potential ENOVA funding if this option is selected. It is therefore apparent that this should be taken forward as an option in the specification, with more detailed analysis in the FEED phase to search for further optimisation and funding opportunity.

During this screening it was also apparent that further savings in OPEX and CO_2 intensity could also be available and are will be further studied in the FEED phase. These include air lubrication, CO_2 capture technologies (a target is already to leave at least space and tie-ins in the current design to accommodate the latest CO_2 capture technology from the flue gas on the ship) and future iterations of fuel sources like hydrogen, that overall could offer synergies for ships involved in CO_2 transportation businesses.

Recommendation: Continue with hybrid as an option in market engagement

Conversion options

All studies to date have discounted the use of Platform Supply Vessels (PSV) as a target for conversion. This based on previous studies conducted by Partners where PSVs where screened for use as LNG Bunker vessels. Those studies proved unfavourable, and its notable that none of the c.15 LNG bunker vessel projects have yet considered conversions. The similarities between the LNG bunker vessel model and the CCS model are apparent – in that they are both similar sized vessels with some similar technology changes compared to the available ships on the market, and both are first-of-a-kind infrastructure development projects, where shipping is a key enabler to the success of the project.

A technical concern for the use of PSVs is the high density of the cargo, and stability issues that will result based on the need to place the tanks very high in the hull. The work scope for conversions will also be very high in this case, further increasing risk exposure in execution, which is already naturally high in the case of conversion. Also, notable for PSV conversion opportunities is that realistic size PSVs have deadweight of approximately 5,000T, so a converted PSV CO_2 tanker would be around 4,500m^3 capacity, which is smaller than target.

The target vessels are similar sized to LPG vessels, however, there are still technical issues to resolve, as-well as re-engine etc., due to the density of the cargo. This is likely leading to reduced filling limits and a need for larger ships to be procured increasing the cost. A cost-benefit evaluation done by the project supports the recommendation of new build vessels.

Recommendation: Select New Build vessel

4 Operation and Maintenance

4.1 Operating philosophy

The Northern Light terminal will be organized under NES as asset/operation owner. NES NEO (NES operations) has limited operational experience within terminal operations and need to seek experience from other facilities for support.

Technical and operational support will be provided by nearby facilities. Facilities with terminal competence is located in nearby vicinity as shown in Figure 4-1.

Preferred solution for operational, technical and maintenance support organization is planned to be decided by NES NEO at end of October 2018.

The support to include but not limited to:

- Mooring services
- Maintenance/Technical
- Lab
- Jetty operators/Loading Master
- Waste handling
- CCR competence

The Northern Light Terminal will be a partly manned installation. The plant will be designed for low manning, utilizing a high degree of automation and set up for remote CCR. Limited administrative and technical personnel is needed for visitors and daily maintenance.

The Operation Model when selected for the Northern Lights terminal will utilize and be based on Equinor`s principals for Integrated Operations. The aim is to improve the quality in all operation processes.

Figure 4-1 Location of nearby facilities

4.2 Maintenance philosophy

Maintenance management system.
The maintenance strategy will form an important basis for the organisation and maintenance programs.

A specific maintenance strategy will be further developed prior to DG4. The preferred strategy is condition based but there could be regulatory requirements for time-based maintenance. For condition-based maintenance, advanced instrumentation is needed along with proper analysis of the technical integrity of the different systems which could increase CAPEX. Capex/Opex analysis must be carried out to determine the best solution.

Safety system and maintenance strategy
The safety systems main purpose is to increase safety in terms of preventing hazardous, undesired situations and handle hazardous situations. This in order to rescue and secure life, health, environment and facility.
Maintenance system shall prioritize safety critical maintenance and integrity.

4.3 Cessation

Details for cessation will be developed in the FEED phase.

5 Regularity assessment

Availability target has not been set for the ship nor for the CO_2 receiving terminal or downstream injection system. The selected concept is an optimization considering CAPEX, OPEX and expected system flexibility and robustness. Examples of concept choices impacting the overall regularity are given below.

- Number of ships: Ship is a major CAPEX contributor as well as adding on to the OPEX. Based on the logistic studies, a concept with one ship per capture plant has been selected as a robust solution.
- Number of wells: A well is a major CAPEX contributor with the cost for drilling, completion and additional subsea equipment. The risk of downtime for the well is considered to be low. However, for an unplanned event requiring well intervention the duration of no availability could be significant in a concept with only one injection well. A common decision has been made in the conceptual study to accept this risk and invest in only one well for the initial volumes. The subsea structure allows for tie-in of additional wells to accommodate higher injection flowrates or increased availability if required.
- Onshore facilities: Early availability assessments have been carried out for the current onshore design including pump configuration, heaters etc. A Production Assurance Program (PAP) will be developed by Equinor as part of the FEED. PAP is a management tool in the process of achieving production performance objectives by cost-effective means. Further analysis assessing failure modes, frequencies and consequences will be part of engineering in the next phase.
- Intermediate storage volume: The tank volume onshore is based on receiving a full cargo volume from one ship at a time. There is some buffer capacity in the current design, in addition to the ability to inject at the same time as CO_2 is offloaded, however the concept does not allow for offloading of several ship volumes in the event of longer periods of downtime in the injection system.
- Design criteria for jetty occupancy is set to 60%. With the current off- loading flowrate and cargo, jetty capacity is not fully utilized and can allow for additional ships.

6 Technology assessment

6.1 Technology assesment

6.1.1 Technology applied in Northern Lights

The Northern Lights project intends to utilise standard and proven technology used in the CO_2 industry and no showstoppers have been identified during the technology maturity mapping process.

Technology maturity mapping are performed by evaluating the Technology Readiness Level (TRL) of the planned design. The definition of readiness level ranges from TRL 0 (unproven idea/proposal) to TRL 7 (proven technology) where TRL 4 (Technology qualified for first use) is the minimum requirement for the project to enter execution phase.

There are some components at TRL level 3 (unknown to Equinor and with limited industry history) within Northern Lights application envelope that will be further matured. Examples are components where Northern Lights application area deviates from that of Snøhvit and Sleipner (incl. Shell's Quest facilities) on e.g.pressure regime, volume rate or fluid composition. The table below summaries the relevant components.

Table 6-1 Technology Northern Lights

Discipline	**Technology**	**Evaluation**
Ship	Material- High Tensile Steel Tanks for ships	Cost saving identified in change of material in ship tanks from IGC code. Engagement with Classification Societies (DnVGL, LR and BV) showed concept credible. FEED activities involve • qualification of material suppliers/manufacturing sites • formally close class B comments from DnVGL (Approval in principal) • assessment of construction methodology, welding techniques, controls and acceptance criteria • audits and additional testing at sites other than the shipyards, • competent oversight from Owner and Charterer representatives in addition to Classification and Shipyard QA teams at additional sites.
Interface ship/onshore	CO_2 loading	Loading operations for ships and barges with liquefied gases are common practice and loading arms for these applications are considered as mature technologies. For CO_2, Yara has extensive experience for loading with hoses, but in a smaller scale. Considering the increased flowrates and cost risk evaluations, the project has decided on loading arms although hoses are considered feasible. Some material testing will be carried out for the selected loading arms vendor.
Interface	Metering	Measuring volume or mass flow rates of liquid CO_2 in large scale is common practice in connection to CO_2-EOR as well as CCS projects. A wide range of metering methods exist with orifice plate meters and turbine meters being the most commonly used. Each metering device has its advantages and disadvantages regarding measurement range (turn down capability), complexity, maintenance demand, accuracy, etc. Certain meters are better suited for the application in

Discipline	Technology	Evaluation
		supercritical or two-phase as well as higher level of impurities than others. The requirement to the metering packages at Northern Lights varies with the intent represented by fluid custody transfer (EU Emissions Trading System directive ETS), quality control (CO_2 purity, measurement of oxygen and water content eg.), plant processing control, diffuse CO_2 discharge reporting and the storage regulative. There are several technologies identified that can be used for measuring water content and other trace components in a CO2 stream as optical sensor, capacitance, gas chromatograph or laser spectrometer. The technology will be further investigated and chosen as part of FEED. The project assessment concludes that continuous flowrate-based metering for custody transfer is not yet qualified to the directive requirements. However, by copying the LNG concept where ship tank volume level is used for custody transfer, technology qualification of flow-based metering will not be required for this phase. Verification of the radar technology for CO_2 will be carried out as part of FEED.
Onshore	Tanks	Storage of liquefied gases at low temperatures and low pressures is common practice. The CO_2 industry standard solution is cylindrical tanks, since they are considered the most cost effective and safest solutions. They are normally manufactured and welded entirely in the workshop of the supplier, providing good quality assurance. Spherical tanks require lower wall thickness, but most often require extensive manufacturing and high-risk welding work on site (post-welding heat treatment). Northern Lights project has chosen 2x6 vertical cylindrical low temperature carbon steel tanks, similar to the existing tanks utilized by Yara.
Onshore	Pump	CO_2 pumps are regarded as a mature technology and respective components are available off-the-shelf from several vendors. Equinor have experience from operating the CO_2 pipeline at Melkøya (Snøhvit) although the upstream pressure is higher than that of Northern Lights (60 bar from upstream compressors vs 15 bar at Northern Lights). Northern Lights has some additional challenges in covering the entire operating envelope. This will be further discussed with pump suppliers in the FEED phase
Onshore	Material-elastomer	As a general recommendation from Quest, elastomers should be avoided when possible and this is the base case for the onshore design. R&D material in Equinor has performed extensive testing and have identified qualified elastomers for CO_2 fluid. For components where elastomers cannot be avoided, material datasheet from the supplier shall be investigated and approved for use.
Onshore	Heaters	Heating of liquefied gases is considered common practice using amongst others electrical heaters, air heaters with natural and forced convection, as well as heat exchange with other fluids. The heaters chosen should have a proven reference

Discipline	Technology	Evaluation
		from similar CO_2 service, if not some degree of technology development might be required.
Pipeline	Design	Fracture propagation control of CO_2 pipelines. Study performed.
Pipeline	Design	HFW linepipe as alternative to seamless linepipe. Study performed.
Pipeline	Material-pigging discs	The use of elastomers cannot be avoided for the sealing discs in the pigs. Impact on elastomers in a depressurization scenario can be severe as experienced during Quest pigging operation. Pigging supplier material datasheet shall be evaluated by R&D prior to acceptance.
Pipeline/SPS/Well	Software-OLGA	The OLGA software for CO_2 behavior in operation pipeline and tubing has been used in design. The model is acceptable when the CO_2 is in fluid conditions and thereby sufficient for Northern Lights project. Further tuning and improvement of the OLGA software could increase confidence for two-phase/transients and thereby expand the operational envelope, see table below
Subsea Production system/Drilling downhole	Material-valves	The Master and Wing valves in a standard X-mas tree contains elastomers. Such trees are currently installed at Snøhvit and the relevant vendor material has been tested by Equinor R&D. Northern Lights vendor may use other elastomers and the material datasheet shall be evaluated by R&D prior to acceptance of use.
Drilling downhole	Material- CO_2	CO_2 purity requirements are aligned with the chosen pipeline material. Downhole material may be exposed to contaminated CO_2 when experiencing formation water flowback at transients. Project has performed testing to qualify material and avoid selection of costly material.

6.1.2 Technology future phases

As part of concept engineering phase other technology elements have been evaluated, technology that is less mature, but with the potential of reducing the CAPEX investment. It is expected that the maturity level TRL4 will not be available to be used for Northern Lights initial infrastructure but may be implemented in future extension.

The Northern Lights project collaborates closely with the strategic R&T project Low carbon and methane technologies (LCMT). One important objective of the LCMT project is to build a portfolio of low cost CCS technologies and concepts that can accelerate the development of a CO_2 transport and storage infrastructure. The Northern Light project is the first step in a possible infrastructure development across borders, thus business need to realise third party CO_2 volumes to Northern Lights is guiding key technology deliveries in the LCMT project.

The sections below detail in more detail the activities performed and ongoing for future phases and operational improvement.

Table 12: Technology development projects

Discipline	Technology	Evaluation
Ship	Low temperature/low pressure	As is described in the Chapter 3.8.4, low pressure ship tanks will be a key to reduce ship logistic cost having larger tanks and cargo onboard each ship. Multiple studies have concluded that operating close to the triple point is acceptable although no actual de-risking of the operational challenges has been performed. R&D in cooperation with SINTEF, partners carry out a work stream to conclude.
Subsea Production system	Electric valves	Avoiding hydraulic valves remove need for hydraulic lines in the umbilical. Project monitor an ongoing technology development program.
Subsea Production system	Subsea MEG tank	Subsea liquid, e.g. MEG, is needed for annulus management and valve testing. Only small volumes are needed. Subsea tank with pump system combined with electrified valves would remove all liquid lines in the umbilical. Solution has been presented by multiple suppliers, but not yet in use.
Interface	Metering	For future commercial CO_2 business, it may be required to perform in-line flowrate measurement for custody transfer rather than ship tank volume. Commercialized CO_2 ship transport will introduce multiple actors and the storage JV may require a local metering under JV control. The qualification of future metering is planned to take place at the Northern Lights facilities during operation.
Interface	OLGA Software	Ensuring liquid conditions during injection in all part of the system puts a restriction on operations. Low pressure reservoir conditions drive need for small tubing which puts an upper limit on the well maximum capacity. Knowledge and understanding of CO_2 behaviour in low pressure/high temperature conditions may release operative restrictions and flexibility. Improvement of the OLGA software is an ongoing work program where the operational experience from Northern Lights will be valuable.
Well	Downhole choke	Qualification of a downhole choking component may enable future batch CO_2 injection and ensure liquid flow conditions also in low-pressure reservoir.
Safety/Process	Vessfire Software	Improvement of the Vessfire software to perform simulations of pressure release of vessels, loading/offloading operations. This work program

Discipline	Technology	Evaluation
		aim to support increased understanding of CO_2 behavior and associated risks
Safety	Software – subsea dispersion analysis	Purpose to estimate consequence of CO_2 discharge subsea

6.2 Confidential information and patents

Not applicable at this time.

7 Execution strategy

7.1 Project execution

The following development strategies are planned for the facility scopes:

<u>Well</u>
The first injection well will be drilled in two stages. Stage one will be the drilling of a vertical confirmation well without completion. This well will give necessary information for final well design and material selection. Stage two will be drilling of a sidetrack from the initial wellbore, and completion of the well to prepare for CO_2 injection.

<u>Ship scope</u>
The ship design is based on newbuilt vessels with minimum modification from standard LPG ships.

<u>Onshore facilities</u>
A greenfield development at Naturgassparken has been selected. Some key infrastructure/utilities will be provided at the battery limit by 3rd parties (electricity, sewage, water, roads, fiberoptics, construction jetty, laydown areas, camp facilities). The plant will be self-sufficient with other utilities and will also include the facilities necessary for storing and handling of consumables and minor maintenance. Larger maintenance and storage of larger spare equipment will be outsourced. There will be a local control room, but the facilities will be designed for remote operations as the normal operating mode. A high degree of prefabrication of piperacks and modules is planned for.

<u>Pipeline</u>
A newbuilt pipeline is planned from the onshore facility to the injection point. Installation method will be selected based on competitive tendering.

<u>Subsea scope</u>
The first well will be installed as a single well satellite. The subsea system will have tie-in points for future extension of the subsea layout. Additional wells may be located up to 20km distance from the first well location.

7.2 Procurement

7.2.1 Procurement goals

Establish the best possible contract strategy with the overall purpose to get on time deliveries with the rights quality at lowest possible cost.

7.2.2 Procurement regulations

Procurement processes for contracts in the execution phase will either be run according to Equinor’s procurement requirements or according to Public Procurement Regulations (PPR).

The project has assumed a level of state support higher than 50% which is the threshold for when the Public PPR shall be used. PPR Section 1-3 states that works contracts and related service contracts funded by more than 50 % state support shall be concluded according to PPR. However, there are several goods and services explicitly exempted from PPR. The project has gone through all contract scopes to assess whether PPR must be followed or not for the relevant goods and services in question. If it is concluded that PPR is not to be followed, Equinor’s procurement requirements will be adhered to.

7.2.3 Procurement strategies

Contract strategies are established for all main execution contracts.

7.2.4 Suppliers

High diversity in scope needed in the project execution phase means we must approach different suppliers in different market with different characteristics and dynamics.

7.2.5 Long lead items

Several long lead items are identified, however if the current project plan is carried out there is no need for pre-investments other than items related to the confirmation well.

8 Value Improvement Process

The project team has executed several VIP initiatives during the Concept study phase and adopted a structured process to capture these. There has been significant focus on reduction of cost throughout this phase.

The key cost saving initiatives are:

- Standardisation of ships
- Reduction of umbilical requirements and length
- Reduction of interim storage volume and ship size based on logistic study, including reduction of jetty length and depth requirements

VIP activities have been recorded as:

- Dedicated workshops, e.g.:
  - Concept hit team report at entry of study phase
  - Competitive scoping workshop based on structured methodology developed by Shell
  - Metering
  - CO_2 specifications
- VIP database containing 76 specific improvement proposals where 31 have been implemented and 22 are carried forward into FEED, see illustration below for details
- Part decisions, key items listed below:
  - 019 Include future volume functionality in phase 1
  - 020 Metering philosophy (Regulatory requirements)
  - 022 Need for onshore plant CO_2 cooling (refrigeration) system
  - 025 Decide if Northern Lights shall implement permanent seismic installation at seabed or acoustic fiber optic sensing in well
  - 028 Conclude tank volumes for ship and injection terminal (logistic study)
  - 029 Conclude on LNG supply; method and location
  - 034 Conclude on requirement for onshore isolation valve at pipeline landfall
  - 036 Decision for land location for subsea control station
  - 052 Reduce cost by reducing length of jetty 1

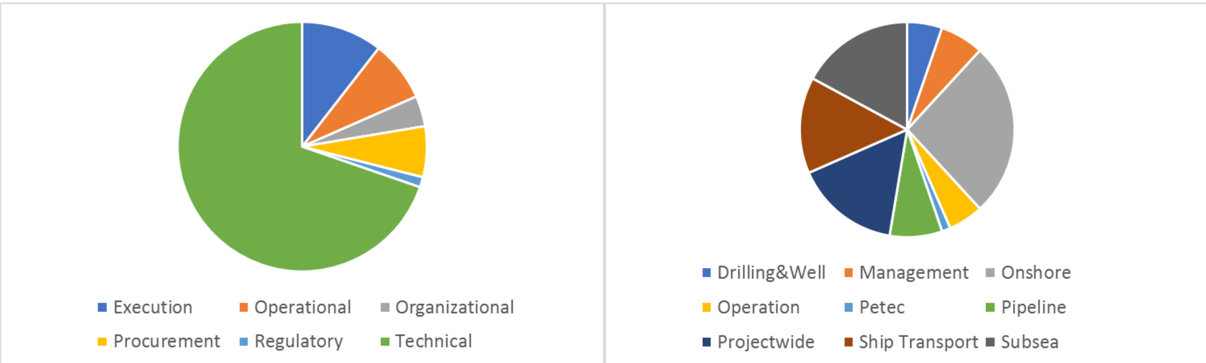


Figure 8-1 Distribution of VIP initiatives in a) areas and b) disciplines

9 Schedule

9.1 Schedule Basis and Changes

The schedule has been developed to show major milestones and to give an overview of, and be able to follow up, key activities within the business case.

Schedule assumptions:

- Combined DG2/DG3 is planned for 15.02.2020.
    - A prerequisite for DG2/DG3 approval is that SSVP have been reached.
- State FID (ready to start contract obligations) will be 30.06.2020.
- DG4 date is planned for 01.10.2023. This date is aligned with the capture sites.
- A set of common decisions shall be made before start FEED 01.12.2018. The common decisions are as follows:
    - Selection of pipe size
    - Functional specification for ship transport
    - Way forward for Subsurface
    - Design Basis freeze
    - Number of wells
    - Storage complex
    - Concept freeze for Onshore facilities
    - Procurement strategy for ship
- The governmental processes:
    - Zoning plan, Impact assessment and PDO/PIO are planned for approval in due time before State FID.
    - Joint Venture agreement effective date is planned for at State FID
    - Negotiate detailed agreement with MPE is planned to finish before start execution 31.08.2019.
- Aurora Validation Point (AVP) is planned for 31.03.2019.
- Subsurface Validation Point (SSVP) is planned for 01.02.2020.
    - Main activities needed to fulfill requirements for SSVP, included drilling the well and perform data analysis & verification, are planned to finish before / at SSVP.
- Drill the well:
    - Planning / preparations for drilling the well in November 2019 is ongoing.
    - Drilling window is planned to start 1 month after delivery of subsea structure
- Subsea structure EPC (satellite, wellhead) is ongoing:
    - Delivery and installation of structure (satellite, wellhead) delivery are planned for in October 2019.
    - XT delivery and installation are planned for in April / May 2023.
- Subsea / Pipelines:
    - Contracts, incl.long lead items (linepipe, subsea valve at pipeline end module etc.) will be awarded at State FID.
    - Onshore pipeline installation is planned for April – August 2022
    - XT and Umbilical deliveries are planned for in April 2023.
- Marine Operations:
    - Installation of Subsea satellite / wellhead in October 2019 (ref. previous bullet on Subsea structure EPC)
    - Pipeline installation offshore is planned for in April – August 2022.
- Umbilical installation is planned for in May 2023.

9.1.1 Drilling & Well

Subject to delays due to Exploration drilling releasing the rig, scheduled start date for the confirmation well is 1 November 2019. The expected completion date of the base case confirmation well is 24 December 2019 with P10 and P90 dates of 10 December 2019 and the 8 January 2020 respectively.

The expected confirmation well schedule will be impacted by decisions relating to the scope of formation evaluation and injection testing.

The base case injector design is scheduled for start on or about 1 September 2023 and has an expected completion date of 23 September 2023, with P10 and P90 dates of the 17 September 2023 and the 30 September 2023 respectively.

The expected injection well schedule will be impacted by the design dictated by the results of the confirmation well evaluation.

9.1.2 Marine operations

Most subsea contracts, with the exception of the confirmation well subsea facilities contract, are planned to be placed at the State FID. The procurement process leading to the contract awards is expected to be executed during the period from end of FEED to State FID.

Confirmation well
In September 2018, a common decision was approved to start the process for the engineering, procurement and fabrication of all the required elements to drill a keeper well, namely a single well satellite structure and a wellhead system with associated tooling.

The contract for fabrication and delivery of the satellite structure and wellhead system has been awarded to Aker Solutions. The delivery is planned for 1 October 2019. The installation campaign for the satellite structure, if confirmed, will be executed during the month of October 2019, prior the start of the drilling rig window starting on 1 November 2019.

Marine installation schedule
Based on the planned date for DG4, on 1 October 2023, a preliminary and generic Marine Installation Schedule has been established.
The generic schedule shows preliminary timelines and durations for the expected work scope and gives an overview over the marine building blocks and required installation work activities.

Timelines and durations will be matured in line as the subsea equipment design is further developed and the drilling schedules are updated based on additional subsurface information. For the time being, the installation campaigns for the umbilical system and the pipeline have been split into two different seasons to avoid potential SIMOPS on the schedule. However, both could also be executed in the same season as long as the delivery dates for the umbilical and DC/FO are requested accordingly.

The marine installation work is split as follows:

Season 0 (2019):
Structure pre-installation survey
Site survey at Aurora target well
Umbilical system and pipeline route corridor survey
Single satellite structure installation
Drilling of confirmation well

Season 1 (2021):
Pre-lay rock installation

Season 2 (2022):
Pre-lay survey
Pipeline installation
As-laid survey
1 off 6" Spool metrology and fabrication
Flowbase installation
X-mas tree installation (LWI vessel)
Pipeline trenching
Post-lay rock installation (pipeline)

Season 3 (2022 or 2023):
Pre-lay survey
Umbilical installation (2022 or 2023)
Umbilical trenching (2022 or 2023)
DC/FO installation (2022 or 2023, incl. trenching)
As-laid survey
Subsea components installation
1 off 6" Spool installation, tie-in, 1 off umbilical tie-in, 1 off DC/FO tie-in and protection cover installation
Post-lay rock installation
RFO- sequenced campaigns
Drilling (sidetrack from confirmation well) and completion of injection well.

9.2 Milestones in the project schedule

ID	Milestone description	Date
MS-001	M10 – Final FEED report	31.08.2019
MS-002	Subsea structure delivery	01.10.2019
MS-003	Wellhead delivery	01.10.2019
MS-004	Drilling of well, earliest start	01.11.2019
MS-005	SSVP	01.02.2020
MS-006	Combined DG2/DG Approval, CDG3	15.02.2020
MS-007	State FID	01.07.2020
MS-008	Main Civil Contract – Start	01.07.2020
MS-008-1	Site prep complete for start Admin. Building	15.10.2020
MS-008-2	Site prep complete for start HDD Pipeline	01.07.2021
MS-008-3	Site prep complete for start Plant EPC	01.07.2021
MS-008-4	Jetty complete for start installation Plant EPC	15.02.2022
MS-009	Plant EPC – Start	01.07.2020
MS-009-1	Start equipment construction foundations	01.07.2021
MS-009-2	Delivery of first storage tanks at site	30.04.2022
MS-009-3	Complete storage tanks installations	29.12.2022
MS-009-4	Ready for CO_2 export	27.08.2023
MS-010	Pipeline fully protected	01.10.2022
MS-011	1st and 2nd ships ready for start-up	
MS-012	Completion of well, latest finish date	31.03.2023
MS-013	Umbilical delivery	01.04.2023
MS-014	XT delivery	01.05.2023
MS-015	Umbilical fully protected	01.10.2023
MS-016	**DG4 Approval**	01.10.2023

9.3 Project Master Schedule (PMS)

The master schedule is per September cut-off (30.09.2018).

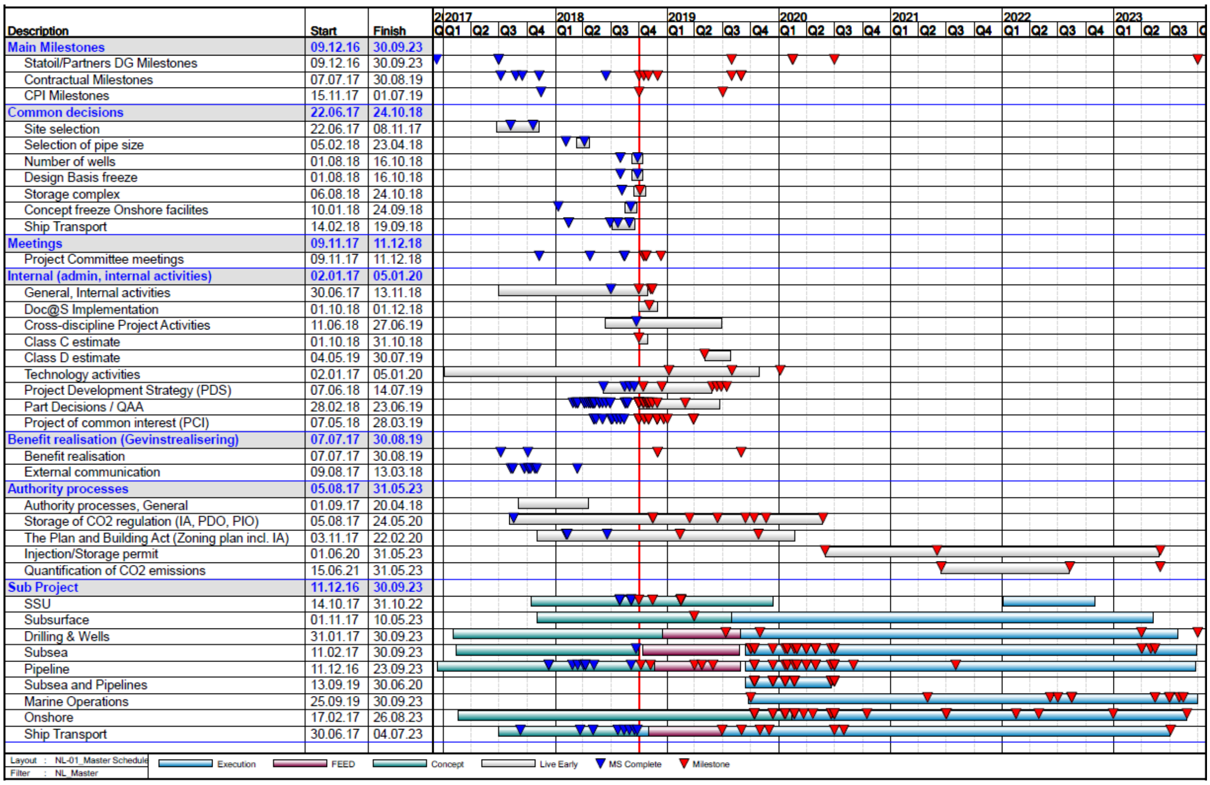


Figure 9-1 Project master schedule (30.09.2018)

Comments to main schedule:
The main schedule consists of all areas within the project's business case and illustrates the summary per area. The various areas are logically linked. Duration of activities are decided based on experience from similar activities on other projects / benchmarking.

9.4 Schedule Risk Analysis

The Schedule Risk Analysis (SRA) was performed to evaluate the robustness of the project schedule, identify risks and uncertainties with regards to the schedule and to align project execution, interfaces and challenges. The following premises and assumptions for the SRA were set:

- Commercial processes according to plan / completed
- Start execution 31.08.2019
- CA, execution for confirmation well 01.10.2018
- Funding from start execution until state FID in place
- Aurora Validation point in March 2019 successful
- QA (KS2) process will be performed by Ministry of Finance's external consultants in due time
- State FID 01.07.2020 (start contract obligations)
- Award long lead item contracts (e.g. linepipe, subsea valve at pipeline end module) at State FID
- Alignment on DG4 date with capture sites

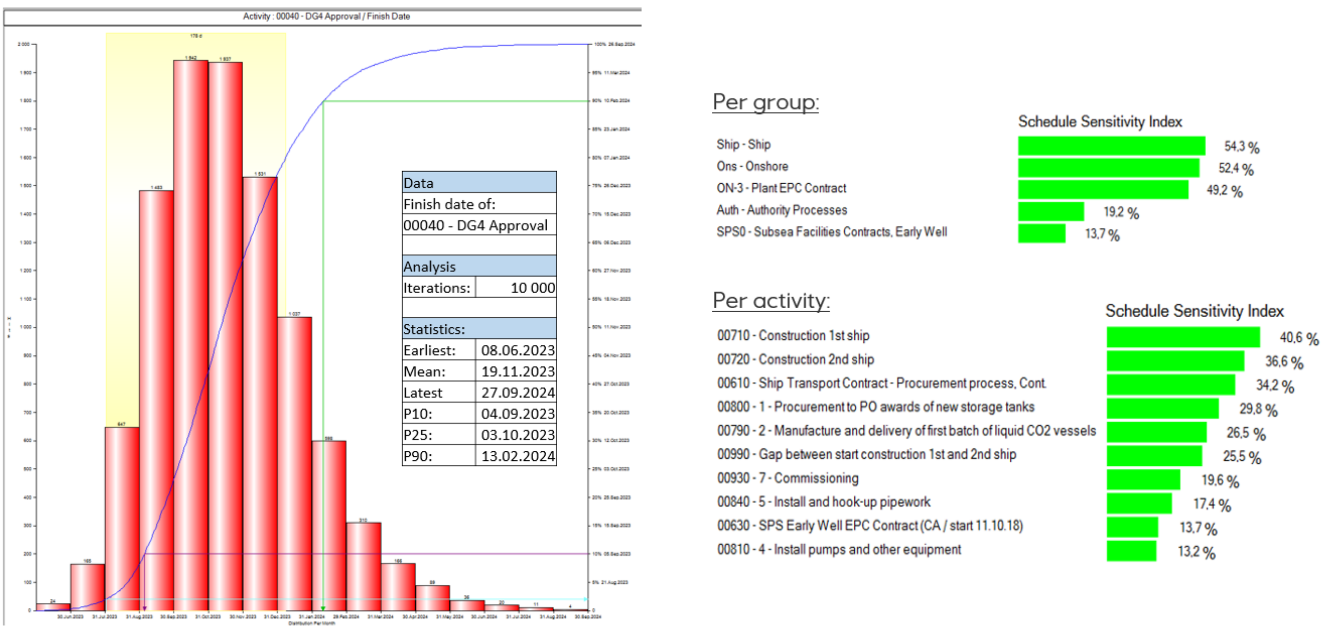


Figure 9-2 Schedule risk results

<u>Comments to schedule risk results:</u>

Basis for development of the SRA schedule was the project main scehdule. It was developed and aligned with the project team. To be able to run realistic simulations, target (fixed) dates were removed from the schedule activities / milestones. The overall results from the SRA shows that the project schedule is feasible but challenging.
The activities most sensitive towards the final project duration are primarily ship transport activites. This is due to the relative pessimistic P90 values defined as actual duration might vary depending on shipyard selected.
Umbilical installation was originally also sensitive to the final project duration, reason for this was planned installation in 2023. After removing target dates it is shown that umbilical can be installed in 2022.

9.5 Critical path and float

Critical path is the chain of linked activities directly affecting the finish date of the project. The following areas have activities that are on critical path – or close to critical path:

Onshore

- The critical path in the network goes through Onshore plant from the ITT process through delivery of the first batch of CO_2 storage tanks, installation, piping and electrical hook-up and commissioning.
- Taking the SRA into consideration this is still the most time critical part of the project.

Ship transport

- The ship transport activities are close to critical path with only 11 days float.
- Activities with long duration (procurement process, construction of the ships), almost on critical path and with high sensitivities have a significant impact on overall duration.

Marine Operations

- Although umbilical installation is originally scheduled for 2023, the SRA shows that both the pipeline and the umbilical can be installed in 2022. For umbilical installation in 2022 there is 57 days float towards DG4. There is, however, a risk for completion of pipeline installation in 2023, this will also push umbilical installation from 2022 to 2023.

Table 9-1 Activities on the critical path

Milestone / Activity description	Target date	Planned completion	Free float*	Total float*
Subsea structure delivery – Installation, finished	01.10.2019	18.10.2019	0 d	15 d
Subsea structure installation, finished – Drilling of well, start	18.10.2019	01.11.2019	13 d	2 d
Drilling, data acquisition & temp. P&A, finished – SSVP	13.01.2020	13.02.2020	31 d	2 d
Site prep complete for start HDD pipeline – Landfall construction	01.07.2021	28.09.2021	0 d	213 d
Pipeline fully installed / leak tested – Start well completion	01.09.2022	02.09.2022	1 d	195 d

***** Free float: Number of days an activity can be delayed without delaying its succeeding activity.
Total float: Number of days an activity can be delayed without delaying the project.

9.6 Project Work Plan

The project work plan is used to outline the activities to be accomplished, timeframes and input needed. It reflects the scope and size of the project.

Activity	Description	Start	Finish	Dur.
08180	Develop final Subsurface report	23.03.19	29.03.19	7 d
05630	Aurora Validation Point (AVP)	31.03.19	30.03.19	0
01510	Geo hazard studies (site survey)	29.04.19	07.06.19	37 d
L3-100	Execution phase (DG3 - DG4)	01.04.19	10.05.23	1480 d
05940	Update / refine models and quality control in DG3	01.04.19	10.05.23	1480 d
01660	Data verification, quick look	01.11.19	22.01.20	74 d
01700	Seismic interpretation	13.01.20	05.02.20	24 d
10750	Data analysis (core and samples)	13.01.20	22.04.20	101 d
10760	SSVP (Subsea Validation Point)	01.02.20	31.01.20	0
02270	Geo-modeling	06.02.20	06.05.20	91 d
01710	Reservoir simulation reference case	06.05.20	06.06.20	32 d
01730	Dynamic uncertainty analysis	06.05.20	20.06.20	46 d
L2-390	Drilling & Wells	30.08.17	30.09.23	2169 d
L3-080	Concept (DG1 - DG2)	30.08.17	18.12.18	454 d
L4-010	Internal Activities	30.08.17	04.11.18	410 d
01410	Completion design, tubing design, lower completion	30.08.17	01.10.18	376 d
01530	Integrity study (Barrier drawings, P&A)	01.11.17	12.10.18	324 d
01540	Well material selection study	01.12.17	19.10.18	301 d
06250	Leakage risk old legacy wells	01.06.18	19.10.18	141 d
01460	Cement and Fluids (drilling, hydraulics, TFM)	15.06.18	19.10.18	127 d
01450	Casing design (Kick calc., Stress check, Casing wear	15.06.18	19.10.18	127 d
10230	Completion design, sand control study (Johansen)	30.06.18	19.10.18	112 d
08230	Blow out potential evaluation (Construction and Injection phase)	26.09.18	15.10.18	20 d
01470	D&W Concept Report	01.10.18	30.10.18	30 d
10240	Blow out kill and relief wells	16.10.18	04.11.18	20 d
L4-030	External Studies / Procurement	01.03.18	18.12.18	281 d
02650	Cement, CO2 (ON HOLD)	01.03.18	01.11.18	234 d
02640	Material study	01.10.18	18.12.18	79 d
L3-090	FEED (DG2 - DG3)	30.11.18	30.08.19	251 d
L4-010	Internal Activities	01.12.18	30.08.19	250 d
10260	Mature concept to DG3 level	01.12.18	30.08.19	250 d
01480	CAR D&W, before M9	12.07.19	11.07.19	0
L4-030	External Studies / Procurement	30.11.18	23.06.19	183 d
02770	Technical studies based on needs from concept phase	30.11.18	23.06.19	183 d
L3-100	Execution phase (DG3 - DG4)	27.08.18	30.09.23	1829 d
L4-010	Internal Activities	27.08.18	30.09.23	1829 d
10720	Detail planning of early well	27.08.18	24.11.18	90 d
10220	Pore pressure, bore hole stability (Aurora)	27.08.18	24.11.18	90 d

Figure 9-3 Snapshot of workplan (1-page extract)

10 Risk Management

Risk management for the project is regarded as an integrated part of the project work. The project director is the overall responsible for the risk work. He is supported by a risk manager for the project. Risk management is a continuous process which requires involvement from all project team members. The project has continuously been focusing on identifying project risks (both threats and opportunities) in the concept phase. These risks have been assessed, and mitigation actions have been defined. The risk manager is monitoring the risk work in the project and facilitates periodic workshops to have an up-to-date risk picture for the project.

The main tasks in project risk management are:

- Identify project risks (threats and opportunities)
- Assess the potential consequences (including risk probability) for each risk
- Decide and prioritize on mitigating actions
- Follow up the risks and the corresponding mitigating actions

The risks are documented in the tool PIMS. This tool is used by all team members and is the basis for risk reporting to all project stakeholders, including the Equinor management and Gassnova. The monthly status report to Gassnova reports on the top 10 risks, e.g. risks which are regarded as most threatening for project success. However, possible opportunities are also highlighted, both technical and commercial. Furthermore, based on request, reports containing all risks and mitigation actions have periodically been issued to Gassnova

For the HSE and subsurface area the most important risks are be documented in the PIMS tool. In addition, more detailed risks and mitigation actions are documented separately.

In addition to the continuous risk activities in the project, risk workshops have been held on a regular basis. The workshops have been arranged per discipline or in some occasions some of the disciplines together. The workshops have taken place bi-monthly and have been facilitated by the risk manager. Participants from all partner companies have attended the workshops.

A summary of the main risks at the end of the conceptual phase is described in section 0.

11 Experience transfer

11.1 Plans for "Gevinstrealisering"

The overall objective of the Norwegian CCS project is to contribute to the development of CCS, so that long term climate goals in Norway and EU can be achieved cost effectively. From this objective four "effect goals" have been formulated, stating that the project shall:

1. Show that it is possible and safe to carry out CCS.
2. Reduce cost for coming CCS projects through learning curve effects and economy of scale.
3. Give learning related to regulating and incentivising CCS activities.
4. Enable industrial opportunities.

Each of these effect goals has been further broken down into specific benefits, 12 in total. The plans for benefit realisation ("gevinstrealisering") are made to meet these objectives, effect goals and benefits.

Equinor did in October 2017 submit a memo named "Benefit realisation – additional to M3 delivery – as requested by Gassnova" (ref. RE-PM673-00009) as input to Gassnova's development of the Benefit realisation plan. There is good alignment between the plan developed by Gassnova and the input from Equinor.

The plans outlined in the October 2017 memo are still valid and constitute the core of Northern Lights plans for benefit realisation. This section will therefore <u>only</u> highlight one important change that has happened since October 2017, and how the project responds to this through its benefit realisation work and plans.

With the Revised National Budget 2018 (RNB 2018), the government increased the importance and urgency of benefit realisation in general, and sourcing of 3rd party CO_2 volumes specifically. Explained simply, 3rd party volumes have been "moved" from being something which the project was to provide plans for how to execute after the partner and state FIDs were taken, to now being something which the project must substantiate in the process leading up to the FIDs.

The project has responded to these new requirements by increased urgency and efforts in its work to source 3rd party volumes, and now has concrete dialogue with 13 potential customers in six countries. This is described in more detail in the sections on "Future business potential" in this report. The shift has also had several positive consequences for the sharing of knowledge and learning, as well as for technology collaboration.

One key positive consequence is that these activities become more targeted, as concrete and engaged private and public 3rd parties now actively seek learning, sharing and collaboration from Northern Lights and other public and private bodies in Norway with CCS expertise. Another key positive effect is that one gets a focused, and aligned, approach for combining the dual pathways of business and policy development that are needed to realise all CCS projects and value chains. The prospects for realising benefits hence increase substantially. **The continued integration of knowledge sharing and technology development as an integrated part of sourcing 3rd party volumes will therefore be a cornerstone in the benefit realisation plans.**

One concrete example is the dialogue Northern Lights has with four companies in Sweden about potentially transporting and storing their CO_2. The companies are from the refinery, biomass and waste incineration sectors. All companies point out that the lack of a Swedish policy and support framework is a major barrier for realising their CCS plans. They need policy development in parallel with their business and project development. Hence Northern Lights has also initiated dialogue with authorities and policy-makers in Sweden, to inform concretely about the Norwegian CCS plans and possibilities for storing CO_2. Much of this dialogue is done jointly with Gassnova, which is seen as a credible and effective dialogue partner for public and policy issues.

These joint dialogues are advancing well, e.g. will two Swedish delegations come for two-day learning journeys ("CCS safari") to Norway in January 2019. The programs are co-ordinated by Gassnova. One delegation will consist of people from Naturvårdsverket, Energimyndigheten, Sveriges Geologiska Undersökelser and possibly also Tillväxtverket. The other will be the newly appointed commissioner (and her staff) tasked with outlining how Sweden can meet its 2045 target for climate neutrality. CCS and bio-CCS are crucial in her mandate. The delegations will meet MPE, Gassnova, Northern Lights, capture companies, TCM and NGOs to learn hands-on about Norwegian experiences and plans.

The Swedish example illustrates a joint way of working where business and policy development are aligned, but not confused, and where Northern Lights and Gassnova works in a co-ordinated way. It also illustrates how 3rd party sourcing, sharing of learning and collaboration go hand in hand. This way of working will also have large potential for other 3rd parties and countries. It is integrated into the plans for benefit realization, complementing what was written in the memo from October 2017.

11.2 Lessons learned

11.2.1 Key Technical learnings

The basis for the concept development work was the feasibility study, where an overall concept was recommended to study further. The main parts of the concept were ship transport of CO_2 from the capture plants, temporary onshore based storage and pipeline transport to a subsea injection site at the Smeaheia location.

After a more detailed study of the Smeaheia reservoir, using newly available 3D seismic, the storage location at Smeaheia was assessed not to meet the expectation of a storage capacity of up to 100Mt per year. As a result, the storage location was changed to the Aurora area in the Johansen formation, leading to an increased subsurface work and deferred subsurface deliveries in the project.

The learning here is that the amount of work related to CO_2 storage characterization before concluding the feasibility of a CO_2 reservoir should not be underestimated, and sufficient time for data acquisition and modelling is essential.
Within the time frame to the investment decision, the project has increased staffing in the subsurface area. Mitigating actions are implemented to achieve a sufficient level of confidence that the storage location meets the required expectations.

Some other highlighted technical lessons learned:
- Lack of common ownership to the subsurface databases has led to much time spent on getting the right access to the information.
- Leakage risk assessment must have high focus in the subsurface work
- It has been of great benefit to use our competence from oil and gas activities and the relevant experience from the injection operations at Sleipner and Snøhvit.

- Leveraging multiple companies' competence from Total, Shell and Equinor has added value in all technical areas.
- It has been challenging, in some areas, to map our oil and gas competence to CO_2 specific design requirements.
- HSE related challenges to CO_2 must not be underestimated, particularly with respect to the shipping and onshore activities.
- Dispersion analysis must be used during the pipeline route selection processes.
- Corrosion effect on well equipment from CO_2 and formation water must have focus in the design.
- Well design on an undefined injection area is challenging.
- It is important to perform an early logistics study for ship transportation
- Use of standard ships and standard jetties are possible and reduce cost.
- Having one project covering both storage and shipping has been successful
- It has been challenging to work effectively with the external interface issues due to the capture plants being unable to be transparent (of competitive reasons).
- External interface work must start early, and interface management understanding is necessary to have an effective total value chain.
- It has been challenging to cut cost and simplify the concept solution.
- The uncertainty in the expected volume of CO_2 in the demonstration project has challenged and complicated the concept design work.

11.2.2 Contractual learnings

- The governance model in the study agreement has been successful and has provided the necessary ability to move forward and meet the targeted milestones
- The study agreement has been firm and effective from a project development perspective
- Technical competence is important to achieve a good contractual governance
- There is limited CO_2 experience in the contractor market
- Positive experience with selecting contractor with local knowledge when studying the pipeline routing
- Public procurement process is manageable but may introduce potential downsides. It has been time challenging to understand the public procurement process.
- Public procurement and company procurement gives a sub optimal combination and could be costlier.

11.2.3 Commercial learnings

- Developing a business model is challenging and expected time schedule has not been possible to meet.
- Lack of firm CO_2 volumes challenges the content of the business model
- Political processes have led to a high level of uncertainty and changes in positions, and consequently delay to the commercial process.
- Undefined business case and immature strategic rationale amongst the partners creates complexity
- Complexity of agreeing in a partnership is under-estimated due to different company governing system and challenges related to strategic alignment
- Defining the business case and product value before concept select has not been achieved.

11.2.4 Regulatory learnings

- The CO_2 storage regulation (Lagringsdirektivet) is not properly suited to the business objective of this project and it is more of an obstacle than enabler for industrial deployment of CCS.
- We regard the storage regulations not being properly suited for offshore projects.
- Legal competence has been essential to understand the regulatory requirements
- It is important to have focus on the competition law in our commercial model work
- Positive experiences and with close interaction with governing bodies involved in the regulation work. As an example, we managed to speed up the exploitation permit process.
- Regulations and responsible uncertainties in the onshore scope has been challenging.
- We are under oil and gas governance to a high degree, possibly leading to a costly design.
- Over regulated for a non-existing business
- The need for a zoning plan area at sea (due to the CO_2 pipeline) has created a critical path for the project

11.2.5 Other lessons learned

- Sourcing the right personnel takes time and continuity in project team is important and increases to chance of success
- The governance model used requires a lot of effort
- Aligning the industrial project development approach with the governmental governance model is challenging.
- Collaboration and stakeholder alignment is extremely important in this type of project

12 Future business potential

12.1 3rd party access to Northern Lights

Northern Lights will establish the world's first large scale "open source" infrastructure for receiving and storing CO_2 from multiple sources and industries. This openness and flexibility is the unique value of the project, since other CCS projects only can be accessed by one or very few CO_2 sources. It makes it possible for any industrial actor that are close to sea and within reasonable shipping distance from Kollsnes to get started with carbon capture at industrial scale. There are about 250 such industrial sites. All they have to do is to capture CO_2 and create the business case which can pay for the full handling of it.

The open nature of Northern Lights enables the partners to get into concrete industrial dialogue with several companies and countries about CCS. Some of these dialogues will hopefully materialize into industrial utilisation of Northern Lights. This provides the optimal platform for further development of additional and larger CCS collaborations.

The new requirements from the government that came with Revised National Budget 2018 has made the sourcing of 3rd party CO_2 volumes more urgent. It has been moved from being something which the project was to provide plans for how to execute after the partner and state FIDs were taken, to being something which the project must substantiate in the process leading up to the FIDs.
Northern Lights is, as shown, planned to be developed in two phases, with storage capacities of 1.5 and 5Mt/y respectively. At most 0.8Mt/y of these volumes will be sponsored by the Norwegian state. This illustrates the crucial role of 3rd party volumes.

The work on sourcing 3rd party CO_2 volumes is structured around a business development (BD) funnel which is regularly updated and revised. The work begins with a desktop overview of promising CO_2 sources in Europe, using a model prepared by Norwegian consultants Endrava with direction and input from Northern Lights, with funding from the Norwegian Oil and Gas Association. From this overview is a shortlist of promising companies and sites identified, with which the project initiates dialogue. The project also responds positively to those companies that independently approach us to explore storage opportunities. The Project has ongoing and concrete dialogues with 13 potential 3rd party customers, located in six countries. These are matured trough a range of approaches, e.g. joint research projects and commercial dialogues.

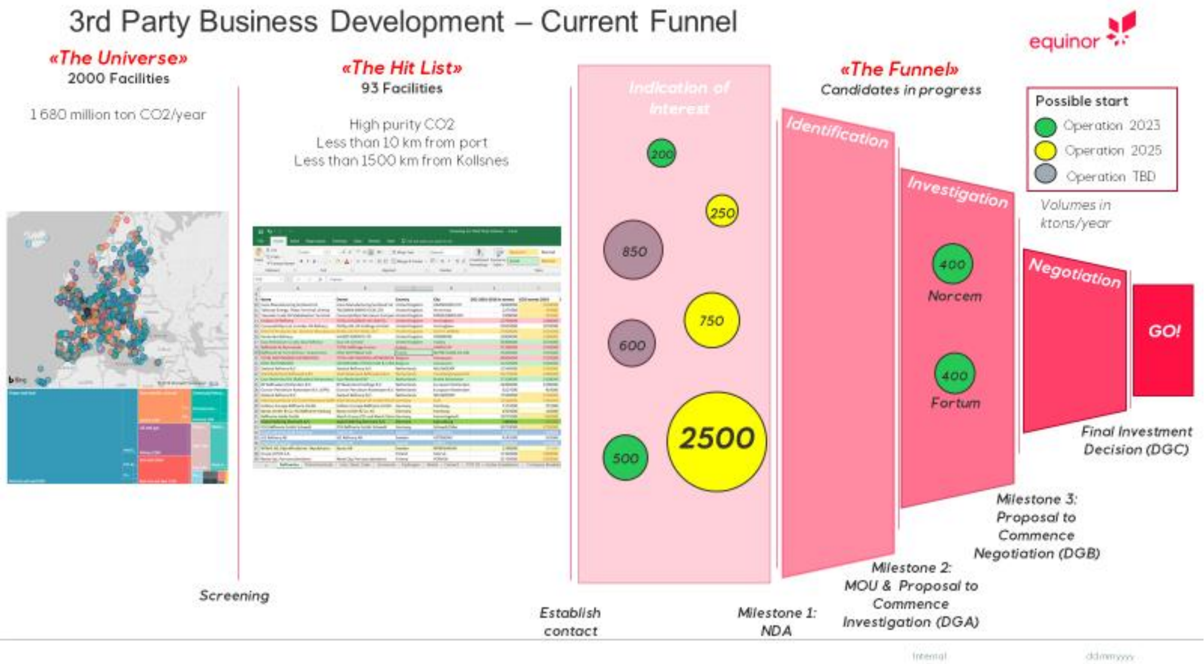


Figure 12-1 Third party business development funnel

It is important to understand that the sourcing of 3rd party volumes includes more elements than what "normal" business development and project development do. This is also about developing markets and frameworks, at the same as business opportunities and the project are matured. All 3rd party opportunities hence need to be matured along three main axes. One is the company axis between Northern Lights and the capture company, where commercial and technical issues are in focus. The second is the national axis between Norway and the capture country. Key issues in that dimension are London Protocol issues, distribution of ETS quotas and long-term liability issues. The third axis is the dialogue between the capture company and its host country about how the appropriate framework and support mechanism for the CO_2 capture can be established. To work efficiently on the first two axes, it is envisaged that Northern Lights and Gassnova often will go together when opening up new 3rd party opportunities. Gassnova will then be the main contributor on the county-to-country axis.

To secure that the work with 3rd parties is done in compliance with competition law, principles and guidelines are being developed. As the first step, the project will establish "clean teams" for those people who are sharing non-public information with and from 3rd parties.

12.2 Enabling CO_2 transport and storage business beyond Northern Lights

All business drivers for CO_2 management, CCS and the Northern Lights project are based on the global need for radically reducing CO_2 emissions as part of the Paris Agreement. Predictions on the scale of needed CCS vary, but according to the International Energy Agency (IEA) and the United Nations Intergovernmental Panel on Climate Change (IPCC) it is between 12% and 20% of the total global reductions. Alternative ways of achieving the same emission reductions without CCS are more expensive, if at all existing. Some industrial emissions can only be reduced by CCS. The ambitious goals for CO_2 reductions (80-95%) in the EU roadmap for 2050 will require CCS to a large extent.

These ambitious targets and commitments create a need for transforming energy and industry systems where CCS has a strong role to play. The Norwegian full-scale CCS value chain project will help get CCS off the ground globally. It will help process industries to abate their CO_2 while remaining in Norway and Europe, retaining jobs and economic growth. Utilization of existing facilities, infrastructure, supply chains and competence will help avoid stranded assets and rising unemployment in Europe´s key industrial regions, Northern Lights is already expanding connections to some of these industrial hubs, tapping into its scale-up potential. Increased European interest in CCS will come with successful demonstration of the technology by Northern Lights.

The project can also be the first step towards establishing the Norwegian continental shelf as a large-scale storage facility for European CO_2, and a demonstration of how CCS infrastructure could be organized and executed elsewhere.

The business potential for CO_2 transport and storage beyond Northern Lights will largely be determined by the extent to which countries and companies will drive CO_2 reductions, and the role which CCS is given in their "tool boxes". The outlook is presently somewhat confusing. On one hand are leading bodies such as IPCC and IEA clearer than ever that CCS is needed rapidly and at scale to handle the climate challenge. Several countries also highlight CCS in their action plans for reaching the Paris targets. On the other hand do some policy-makers and NGOs seem ready to rule out CCS from the climate mitigation tool boxes which they favor, often in combination with unrealistic expectations about what other solutions will be able to deliver. It is envisaged, and a major objective, that a successful Northern Lights project will firmly demonstrate the practical feasibility and attractiveness of CCS, thereby securing that CCS is broadly utilized as the climate solution it needs to be. If so, the business potential for CCS is very large.

To indicate the overall potential market for CO_2 transport and storage, we here refer to the report "*Industrielle muligheter og arbeidsplasser ved storskala CO_2-håndtering i Norge*", (Industrial opportunities and employment prospects in large-scale CO_2 management in Norway), from April 2018. (It was written by SINTEF with assistance of NTNU on behalf of the Confederation of Norwegian Enterprise (NHO), the Confederation of Trade Unions (LO) and four other organisations.

The objective was to demonstrate the potential opportunities for industry linked to a realization of full-scale CO_2 management in Norway. The fundamental – and sound – premises for all market assessments made in the SINTEF report are that the world, including Norway, will fulfil its Paris commitments and that CCS covers the part of overall emission reductions identified by IEA and IPCC.

The market for CO_2 management in Europe will according to SINTEF potentially involve from 30,000 to 40,000 jobs directly linked to CO_2 management in 2030 and from 80,000 to 90,000 in 2050. Norwegian industrial actors are well equipped to increase their value generation in such a market.

There is strong collaboration between the Project and the Partner companies on enabling CCS as a large scale business. This is done through advocacy with policy makers and through business development. Many activities are done jointly, e.g. advocacy with EU and national governments through platforms such as ZEP, IOGP and OGCI. Project development is sometimes done alone, but often also jointly, e.g. as through OGCI and the 3rd party activities in Northern Lights.

12.3 Enabling low carbon energy carriers and other low carbon value chains

Establishing a CO_2 storage site will also enable the development of new low carbon energy carriers. Key options are low-carbon hydrogen produced from natural gas with CCS, and emission-free power produced by combustion of gas, biomass, waste, etc. with CCS.

The Partner companies are advancing new low carbon energy carriers through a combination of political advocacy and business development. The actual business development is mainly done by the individual Partner companies. One example is the hydrogen agenda which Equinor is developing. These are large-scale projects that integrate the CCS value chains and aim to address GHG emissions related to power production, industrial activities and heating. It can create momentum for broad roll-out of CCS solutions EU-wide. Two of the projects stand out:

- **H2M**, which will convert the Magnum natural gas power plant in the Netherlands to run on clean hydrogen produced from natural gas and store the residual 1.3Mton of CO_2 a year.
- **H21**, which intends to decarbonize the heating grid of the North of England (12.5% of the UK's population) through clean hydrogen, which will help avoid 17-18 million tons of CO_2 per year.

A major driver for these projects is the fact that renewables alone will not guarantee security of supply and system reliability due to intermittency and seasonality issues. EU's decarbonisation policies have to a large extent focused on renewables, energy efficiency, as well as electrification of heating and transport. This only addresses a part of the problem.

The possible business opportunities from hydrogen could be substantial. For example did the previously mentioned SINTEF study estimate that investment in Norway in hydrogen production from natural gas may result in sales of 220 billion NOK in 2050, and between 25,000 and 35,000 new jobs according to SINTEF. A precondition for this is, among other things, that adequate storage capacity is developed for CO_2 in the North Sea.

CCS is also the crucial enabler for process industries to be able to transition to emission-free products, whether they be cement, fertilizers, metals or other products. CCS is, of course, also needed for achieving negative emissions through so-called "bio-CCS". The Swedish government has signaled its clear interest in this.

Industrial sector emissions currently represent some 20% of the EU's total GHG emissions. Reaching net zero emissions by 2050 is impossible if industrial emissions are left unaddressed. Industrial decarbonisation must be as cost-efficient as possible. Electrifying steel, cement or other heavy industry will prove expensive. To remain competitive, the European industry needs options that can deliver large-scale and cost-efficient decarbonisation. These options must be replicable and scalable EU-wide. CCS can be a viable option for industrial and power production decarbonisation, especially when combined with clean hydrogen.

13 Abbreviations

AC	Alternating Current
ALARP	As Low As Reasonably Practicable
AVP	Aurora Validation Point
BAT	Best Available Technique
BOP	Blowout Preventer
CAPEX	Capital Expenditure
CCR	Central Control Room
CCS	Carbon Capture and Storage
CITV	Chemical Injection Throttle Valve
CIU	Chemical Injection Unit
CRA	Cost Risk Analysis
DC	Direct Current
DG	Decision Gate
EER	Evacuation, Escape, Rescue
ENVID	Environmental impact Identification
ESD	Emergency Shut-down
ESV	Emergency Shut-down Valve
ETS	Emissions Trading System
FCM	Flow Control Module
FEED	Front End Engineering and Design
FID	Final Investment Decision
Fm	Formation
FO	Fibre Optic
FP	Fully Pressurised (ship)
Gp	Group (of reservoirs)
HDD	Horizontal Directional Drilled
HCS	Horizontal Connection System
HET	Hydrate Equilibrium Temperature
HISC	Hydrogen Induced Stress Cracking
HP	High Pressure
HPU	Hydraulic Power Unit
HSE	Health, Safety and Environment
HFW	High Frequency Welded
HVAC	Heating, Ventilation, and Air Conditioning
IA	Impact Assessment
ICV	Inline Choke Valve
ID	Inner Diameter
IMR	Inspection. Maintenance, Repair
JT	Joule Thomson
JVA	Joint Venture Agreement
KP	Kilometer Point
LD	Leak Detector
LP	Low Pressure
LWI	Light Well Intervention

MEG	Monoethylene Glycol
MEL	Main Equipment List
MLSA	Ministry for Labour and Social Affairs
MGR	Mongstad Gas pipeline
MPE	Ministry for Petroleum and Energy (no. OED)
MPP	Manpower Plan
NEA	Norwegian Environment Agency (no. MDIR)
NES	New Energy Solution (Equinor business area)
NCS	Norwegian Continental Shelf
ND	Nominal Diameter
NDCP	Directorate of Civil Protection (no. DSB)
NFA	Norwegian Fishermen's Association (no. Norges Fiskarlag)
OD	Outer Diameter
OPEX	Operational Expenditure
PAGA	Public Address and General Alarm system
PCO	Pipeline Commissioning Operations
PDO	Plan for Development and Operation
PE	Poly Ethylene
PFE	Power Feed Equipment
PIO	Plan for Installation and Operation
PLEM	Pipeline End Manifold
PSA	Petroleum Safety Authority (no.Ptil)
PSV	Process Safety Valve
PSV	Platform Supply Vessel
RLWI	Riserless Light Well Intervention
ROV	Remote Operated Vehicle
SCM	Subsea Control Module
SCU	Subsea Control Unit
SPFM	Single Phase Flow Meter
SR	Semi-refrigerated (ship)
SRI	Subsea Rock Installation
SMYS	Specified Minimum Yield Strength
SPCU	Subsea Power Communication Unit
SSC	Sulfide Stress Corrosion cracking
SSU	Safety and Sustainability
SSVP	Subsurface Validation Point
TH	Tubing Hanger
TRL	Technology Readiness Level
UTA	Umbilical Termination Assembly
VXT	Vertical X-mas Tree
WEAL	Working Environment Area Limits
WEHRA	Working Environment Health Risk Assessment
WHP	Well Head Pressure
XT	X-mas Tree