Content

Workshop objectives and facilitation

What is the main objective of the workshop?

- Main objective is to facilitate good discussions on the identified long-list of decarbonization technologies for reducing scope 1 emissions and reaching targets.
- The key focus is on identifying and discussing the **main development and implementation obstacles** to further strengthen the assessment of realistic scaling potential, emission reduction potential and application of each technology.
- Note: A separate workshop is planned for discussion scope 3 considerations. As such, this will not be the focus of the TG workshops.

How will the workshops be organized?

- **Meeting agenda (see also pre-read from OG21):**
  - Welcome, presentation of participants: TG leader (15 mins)
  - Introduction to the project: Gunnar (15 mins)
  - Presentation of DNV pre-read: DNV PM (20 mins)
  - Structured discussions on selected technologies: DNV core team and experts (100 mins)
  - Summary and next steps: DNV PM (30 mins)
- **Meeting roles:**
  - DNV PM will be in charge of facilitating the workshop and keeping track of allocated time
  - DNV Scribe will be in charge of taking notes of all inputs provided from the workshops
  - DNV Expert(s) will be in charge of presenting their technology area and participating in discussions
- **Structured discussions on selected technologies:**
  - In cooperation with OG21 and TG leaders, DNV has chosen a few selected technologies to focus on for each TG workshop. This is done to ensure we have time to go into more detail for each technology, and capture input from relevant technology experts.
  - Each selected technology will be allocated a given time for a short presentation from relevant DNV expert, as well as discussions. It will be important to remember the main focus of the workshop and keep track of time.
  - See following slide for the overview of technologies selected for each TG workshop and representatives from DNV

DNV

Selected technologies and DNV participants

Other participants from DNV:

- PM: Frida Berglund
- Scribe and core team member: Daniel Brenden
- Sponsor: Sture Angelsen

Note! As each technology has limited time allocated, it will be important to remember the key focus area of the workshop: identifying and discussing the main development and implementation obstacles

TG workshop	Selected technologies for discussions	Allocated time for short presentation and discussions (100 mins)	DNV experts
TG1: Climate change and environment *Thursday 05.05, 12-15*	1. Electrification (from shore, hubs, offshore wind) 2. Gas power hubs with CCS 3. Compact top-side CCS 4. Hydrogen and hydrogen-derived fuels for power production *5. High-level overview of remaining technologies*	1. 35 mins 2. 20 mins 3. 15 mins 4. 15 mins 5. 15 mins	1. Jørgen Bjørndalen, Yongtao Yang, Frida Mattson 2. Ole Kristian Sollie 3. Ole Kristian Sollie 4. Marcel Cremers 5. No specific experts allocated for this
TG2: Subsurface understanding *Tuesday 03.05, 12-15*	1. Electrification (from shore, hubs, offshore wind) 2. Gas power hubs with CCS 3. Compact top-side CCS 4. Energy efficiency through reservoir management 5. Geothermal energy to reduce electrical power demand	1. 15 mins 2. 25 mins 3. 15 mins 4. 30 min 5. 15 min	1. No specific experts allocated for this 2. Ole Kristian Sollie, Elizabeth Mackie (joining online) 3. Ole Kristian Sollie, Elizabeth Mackie (joining online) 4. Elisabeth Rose, Elizabeth Mackie (joining online) 5. Koen Hellebrand (joining online)
TG3: Drilling, completions, intervention and P&A *Wednesday 04.05, 12-15*	1. Electrification (from shore, hubs, offshore wind) 2. Gas power hubs with CCS 3. Compact top-side CCS 4. Energy efficiency through reservoir management 5. Geothermal energy to reduce electrical power demand	1. 15 mins 2. 20 mins 3. 15 mins 4. 20 mins 5. 15 mins	1. No specific experts allocated for this 2. Elizabeth Mackie (joining online) 3. Elizabeth Mackie (joining online) 4. Elisabeth Rose, Elizabeth Mackie (joining online) 5. Koen Hellebrand (joining online for parts of WS)
TG4: Production, processing and P&A *Monday 02.05, 12-15*	1. Electrification (from shore, hubs, offshore wind) 2. Gas power hubs with CCS 3. Compact top-side CCS 4. Hydrogen and hydrogen-derived fuels for power production 5. Optimized gas turbines (waste heat recovery, utilization) 6. Geothermal energy to reduce electrical power demand	1. 20 min 2. 15 min 3. 15 min 4. 20 min 5. 15 min 6. 15 min	1. Yongtao Yang 2. Erik Hektor 3. Erik Hektor 4. Marcel Cremers Koen (joining online for parts of WS) 5. Erik Hektor 6. Koen Hellebrand (joining online for parts of WS)
TG5: Safety and working environment *Thursday 05.05, 09-11:30*	1. Electrification (from shore, hubs, offshore wind) 2. Gas power hubs with CCS 3. Compact top-side CCS 4. Hydrogen and hydrogen-derived fuels for power production	1. 20 min 2. 20 min 3. 20 min 4. 40 min	1. No specific experts allocated for this 2. Amund Huser, Erik Hektor 3. Amund Huser, Erik Hektor 4. Amund Huser, Marcel Cremers (joining online for whole WS)

Content

Purpose and objective of the study
See also pre-read from OG21, sent out 28.04.22

- **Purpose:** By the end of this project, OG21 has described realistic ways to accelerate technology implementation required to meet the GHG emission reduction targets.
- **Objectives:**
  - Obtain a thorough understanding of potential GHG emission reduction technologies, their technical and commercial readiness levels, application scope and scaling, and development and implementation obstacles.
  - Identify measures and actions that could be taken to accelerate development and implementation of the most promising GHG reduction technologies with respect to GHG reduction volumes, scaling, and implementation timeline.
  - Describe the business opportunity for the Norwegian state as well as for Norwegian industry enterprises in taking a leadership role in petroleum decarbonization solutions (Scope 1, 2 and 3 emissions).
- **Desired outcome:** The findings from this report will play an important part in ensuring OG21 can describe realistic ways to accelerate the technology implementation required to meet the GHG emission reduction targets, as well as how Norway can take a leading role in emerging industries and petroleum decarbonization by ensuring our world leading petroleum companies and solutions provide a competitive edge.

DNV

The study consist of several steps in order to identify the most promising opportunities

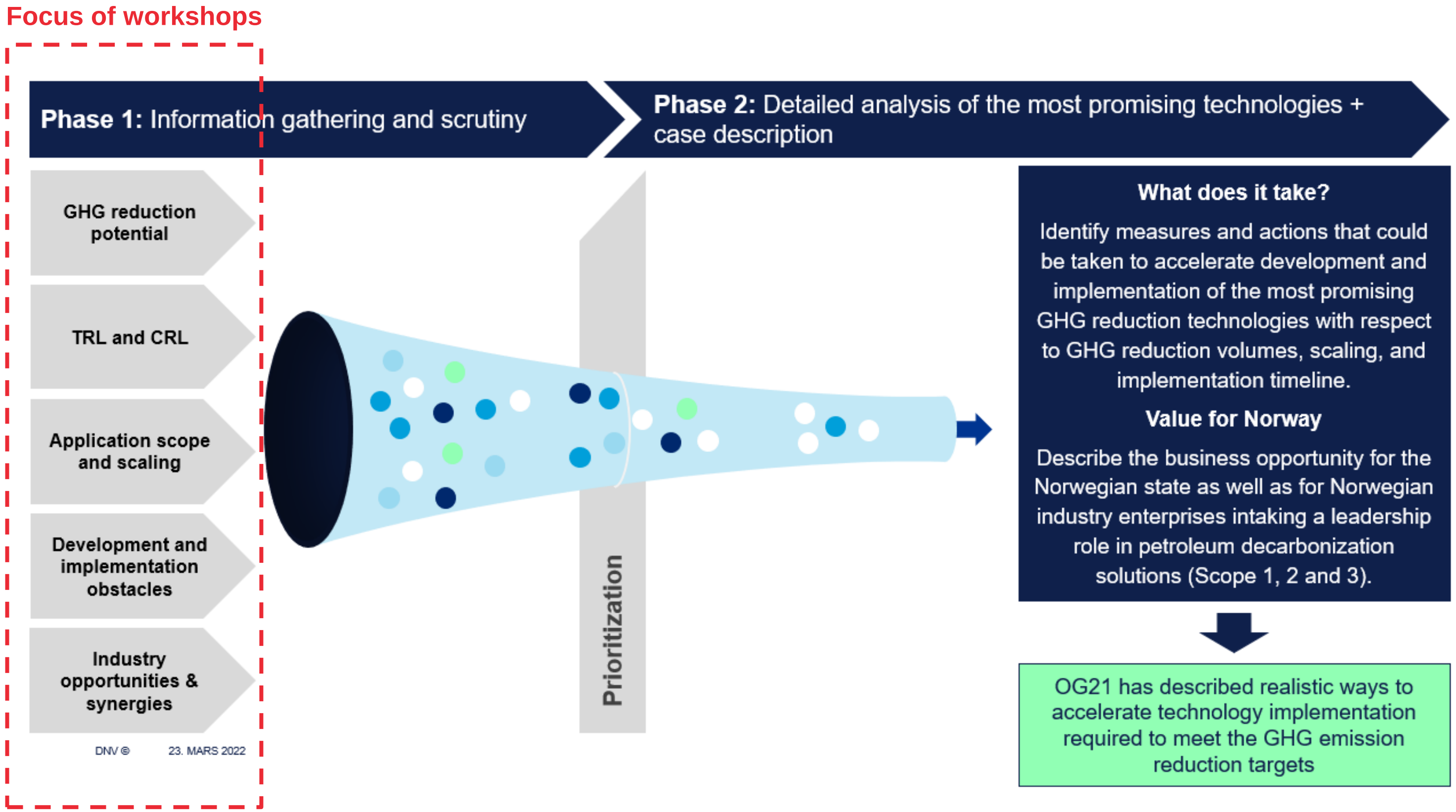
The study is performed in two phases, as seen in the figure.

In Phase 1, a set of decarbonization technologies are described on a high level based on chosen screening criteria. The technologies are further discussed in half-day workshops with all technology groups (TG's) in OG21. This provides us with a solid foundation for prioritizing and agreeing on a short-listed group of technologies that go into Phase 2.

In Phase 2, a more detailed analysis is done of the chosen technologies, including case studies. As part of this phase, we will identify important measures for accelerating development and implementation of the most promising opportunities ("What does it take?"), as well as describe the business opportunities for the Norwegian state and industry ("Value for Norway").

Together, this will provide OG21 with a solid basis for describing realistic ways to accelerate technology implementation required to meet the GHG emission reduction targets.

In the TG workshops, the focus will be to discuss input to the technologies based on the screening criteria as part of Phase 1 of the study.



Content

Introduction to scope 1, 2 and 3 emissions

Overview

Historically, the emphasis of measuring a company's carbon footprint has been to measure direct emissions in the form of scope 1, as well as indirect emissions that are more easily influenced in the form of scope 2. Solid documentation on what Scope 1 and 2 emissions, and strategies to reduce them, are increasingly expected from stakeholders. This type of reporting has long been a feature of non-financial reporting requirements and features in most companies' sustainability reporting.

That said, scope 1 and 2 reporting falls short of capturing the full carbon footprint of a company, as it does not reflect the full indirect emissions throughout the value chain. As stakeholders have become increasingly aware of that scope 1 and 2 emissions are not accurately reflecting a company's real carbon footprint, the focus on scope 3 emissions have picked up. The logical extension of this realisation would be that similar pressures intensify on countries exporting their emissions. In Norway's case, this would be in the form of the scope 3 emissions associated with the oil and gas exports and downstream use.

For corporates and countries, declining scope 1 and 2 emissions can reflect an effective decarbonization strategy within these boundaries. That said, if considered in isolation, such a focus is likely to conceal the full value chain carbon footprint of an activity. For full transparency on sustainability impacts, all three scopes are expected to be captured in order to reflect the true negative externalities of a company's (and country) across its value chain. Corporates are already feeling this squeeze, and it may be prudent to take such considerations into account at the national level in order to bolster the long-term international competitiveness of Norwegian companies and safeguard their sustainability credentials.

Scope 2: Captures indirect GHG emissions from purchased electricity, heat, cooling and steam. Scope 2 emissions are naturally higher for companies that require significant amounts of i.e., electricity to run their operations

Scope 3: Captures all indirect value chain GHG emissions that are associated with a company's operations and not captured by scope 2. This includes both upstream and downstream in the value chain, with the composition of scope 3 GHG emission sources varying widely depending on the company in question, operations, products, services or suppliers.

Scope 1: captures GHG emissions from operations and assets that are owned or controlled by a company and is of notable importance in sectors with high direct emissions such as fossil-fuel based processing industry, electricity generation and manufacturing.

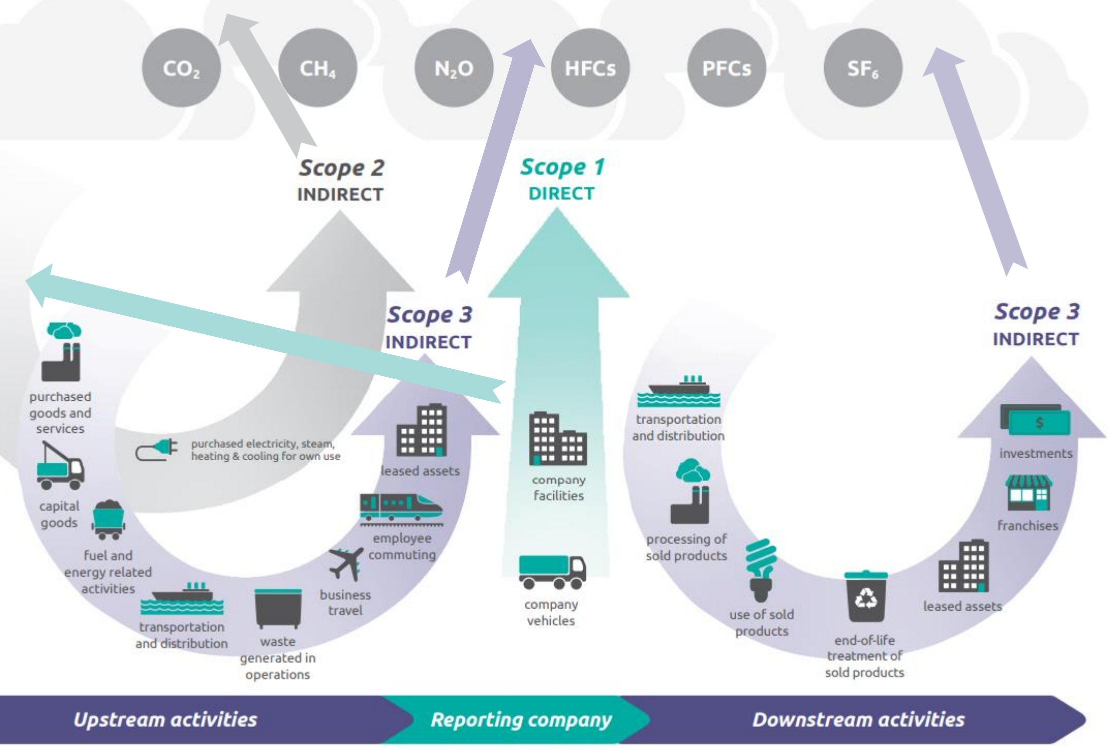
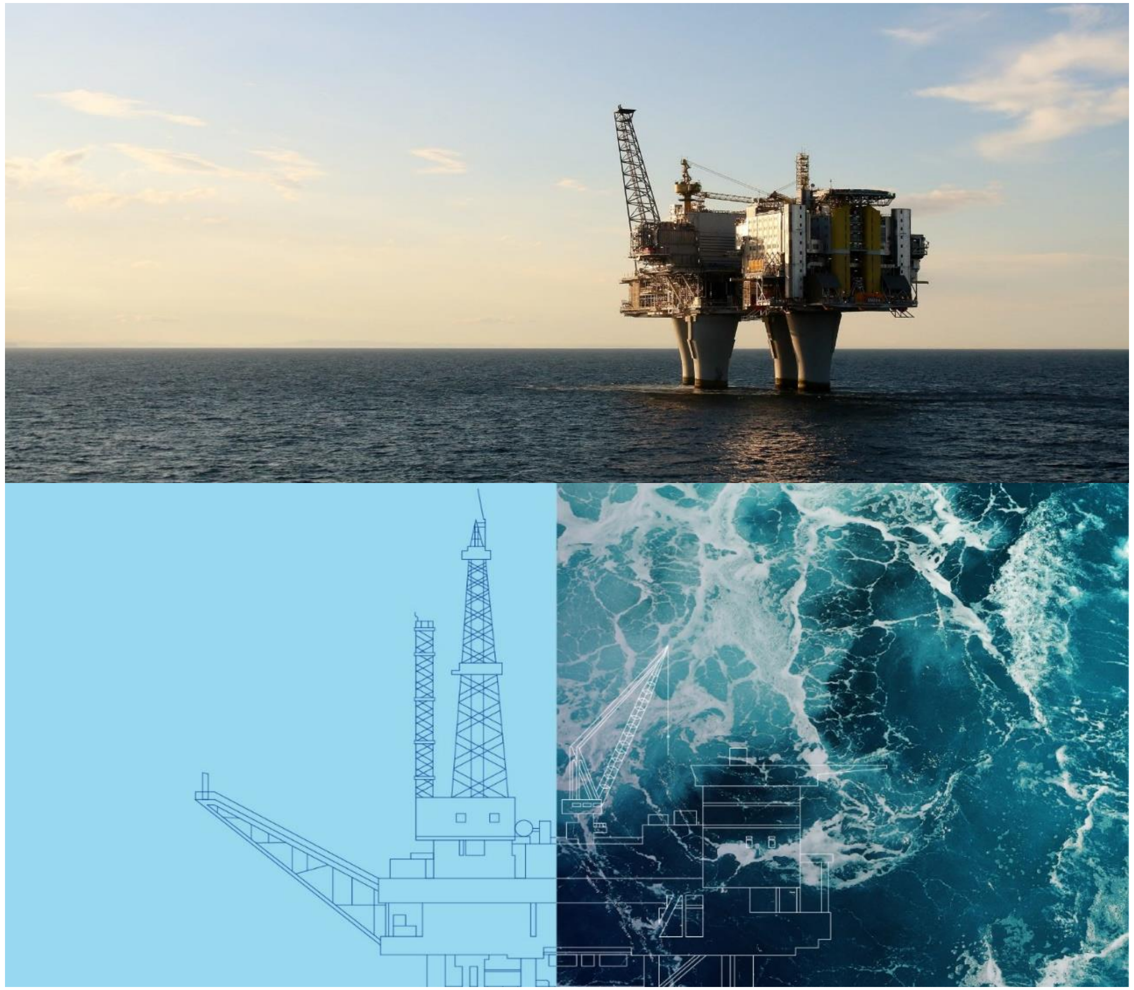


Figure: GHG Protocol

What is scope 1 emissions?

Scope 1 – the start and stop of any decarbonisation

- Scope 1 emissions can be defined as “direct GHG emission that occur from source that are controlled or owned by an organisation” Within this definition, emissions from sources such as fuel combustion, furnaces, boilers, vehicles and so on are measured. For the oil and gas sector, a large share of the scope 1 emissions come from the operation of gas turbines offshore.
- As scope 1 emissions are directly under a corporate’s control, they can be directly positively or negatively influenced by corporate action. Scope 1 emissions are therefore naturally the main focus of carbon emission reduction compliance schemes. For example, carbon trading schemes such as the EU emissions trading scheme (ETS) imposes a carbon emissions allowance cap on scope 1 emissions for various high-emitting economic activities, which declines year-on-year to reflect annual EU GHG reduction targets.
- The overarching decarbonisation focus on scope 1 emissions reflects that any company’s scope 2 or 3 emissions is another company’s scope 1 emissions. Hence, to decarbonize value chains, all companies involved in the relevant value chain must reduce their own scope 1 emissions.
- Based on this logic, strict decarbonization requirements for electricity generators would reduce the scope 2 emissions for all companies buying electricity. Shipping decarbonization would reduce midstream scope 3 emissions for all companies shipping their materials with the relevant shipping company, while natural gas power with CCS would reduce downstream scope 3 emissions for a gas producer. In short, all decarbonization starts with scope 1 emission reductions.

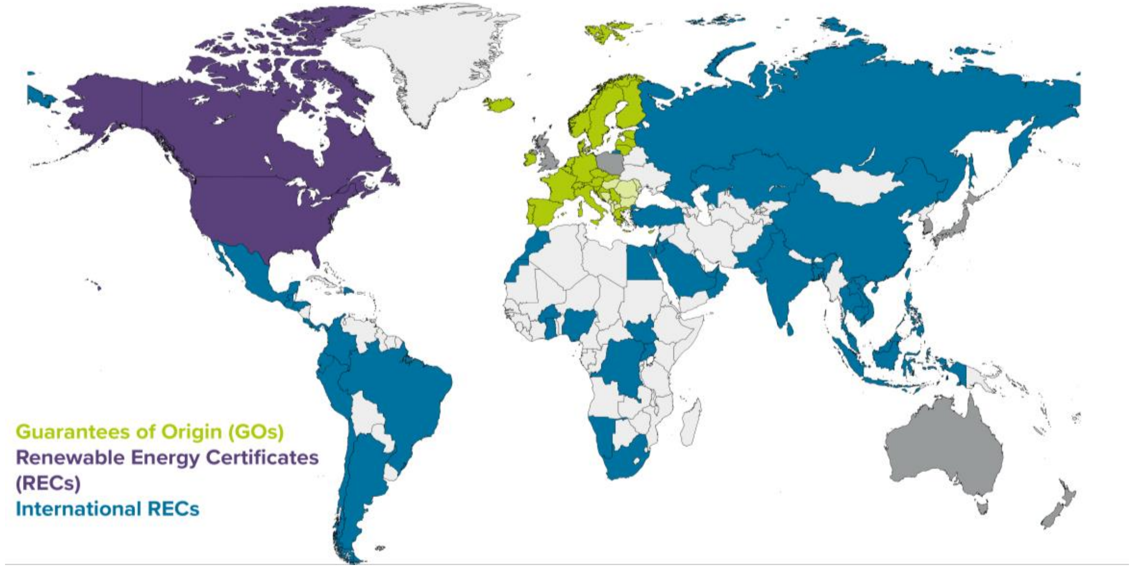


What is scope 2 emissions?

Scope 2 – documenting carbon intensity

- Scope 2 emissions can be defined as “indirect GHG emissions associated with the purchase of electricity, steam, heat, or cooling”. While the emissions are considered scope 1 for the electricity and/or heat generator, they are the result of the demand of the consumer requiring i.e., electricity for its operations. The emissions are thus indirectly a result of that company’s activity.
- Documenting that scope 2 emissions reduce over time is integrally linked to i.e., power generators being able to document that their electricity has a falling carbon intensity. The GHG protocol outlines two main ways that consumers of electricity, heat, cooling and steam can document its carbon intensity, namely:
  1. Location-based reporting: which means reporting on the intensity of the electricity in the national or regional grid. This will thus reflect the intensity of the physical electricity within a defined area over a year.
  2. Market-based reporting: This method enable renewable energy generators to receive certificates that prove the renewable attributes of a unit of electricity. This certificate can thus be sold to an electricity consumer which can cancel such a certificate to prove that a unit of consumed electricity is green. As such, the attributes of the electricity is decoupled from the physical electricity on the grid. The European guarantees of origin scheme (GoO) is a market-based reporting scheme, while the map on the right highlight other relevant schemes.
- There is inconsistency in which of the approaches are used by companies, but the GHG protocol stipulates that both should be reported on.

Schemes for electricity attribute certificates globally



Source: ECOHZ

What is scope 3 emissions?

Scope 3 – the ‘iceberg’ emissions challenge

- Scope 3 emissions can be defined as being the “result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly impacts in its value chain”. The GHG protocol outlines a total of 15 categories for scope 3 emissions.
- The profile of scope 3 emissions intensity will vary from sector to sector. For example, renewable energy projects with zero scope 1 emissions could source services, goods and materials from a more polluting upstream supply chain, leading to relatively high scope 3 emissions. Similarly, Oil and gas companies could have close to carbon-neutral scope 1 emissions from production activities, but will likely by default have high scope 3 downstream emissions from “use of sold products”.
- For some oil and gas companies, scope 3 emissions can represent >85% of the total value chain emissions – notably in the form of category 11 “Use of sold products”. Category 11 emissions can be addressed by decarbonizing fuels upstream – i.e., blue hydrogen or ammonia – or downstream – i.e., natural gas power with CCS.
- As oil and gas companies increasingly are expected to report on scope 3 emissions and include them in decarbonization targets, a logical extension will be that countries over time will be expected to report on emissions outside of its own carbon budget boundaries. For Norway, this could entail a form of category 11 reporting on the use of exported oil and gas and would dramatically increase Norway’s carbon footprint. Hence devising ways to reduce scope 3 emissions for Norwegian oil and gas companies will become a key facet of ensuring the future competitiveness of such companies and safeguarding the value of the industry.

Upstream

1. Purchased goods and services
2. Capital goods
3. Fuel-and energy-related activities
4. Upstream transportation and distribution
5. Waste generated in operations
6. Business Travel
7. Employee commuting
8. Upstream leased assets

Downstream

9. Downstream transportation and distribution
10. Processing of sold products
11. Use of sold products
12. End-of-life treatment of sold products
13. Downstream leased assets
14. Franchises
15. Investments

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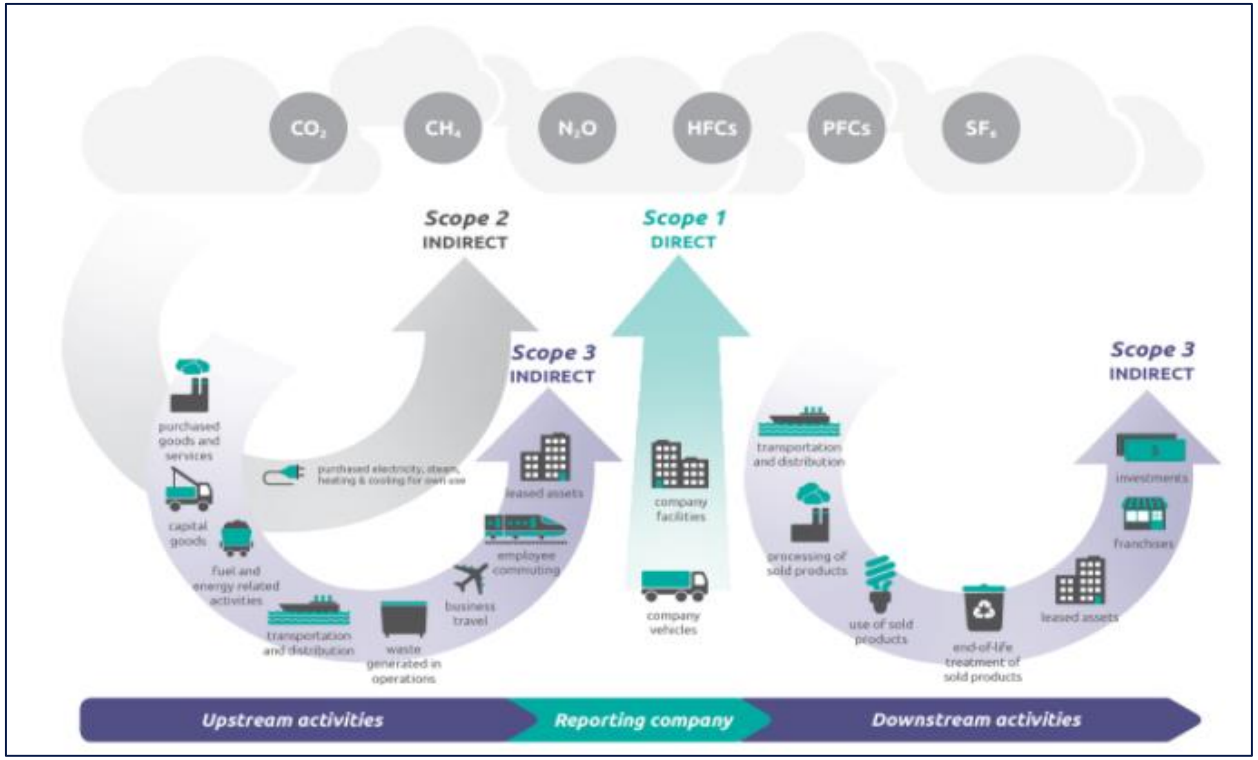
Ensuring consistency between emission levels

- The GHG emission reduction targets are based on the production phase (scope 1 emissions). As such, in order to ensure consistency, we distinguish between scope 1, scope 2 and scope 3 emission reduction opportunities.
- **Scope 1 opportunities/technologies:** Quantitative assessment of GHG reduction potential and scaling – what will it take to meet the targets?
- **Scope 2 opportunities/technologies:** Scope 2 emissions are assessed alongside scope 1 and scope 3 opportunities
- **Scope 3 opportunities/technologies:** More qualitative assessment and top-down approach on the reduction potential and scaling of most important technologies – how can Norwegian petroleum industry stay competitive and ahead of the responsibility trend by influencing indirect emissions?



Content

With current sanctioned and mature measures, emission levels are likely to be down by 29% in 2030

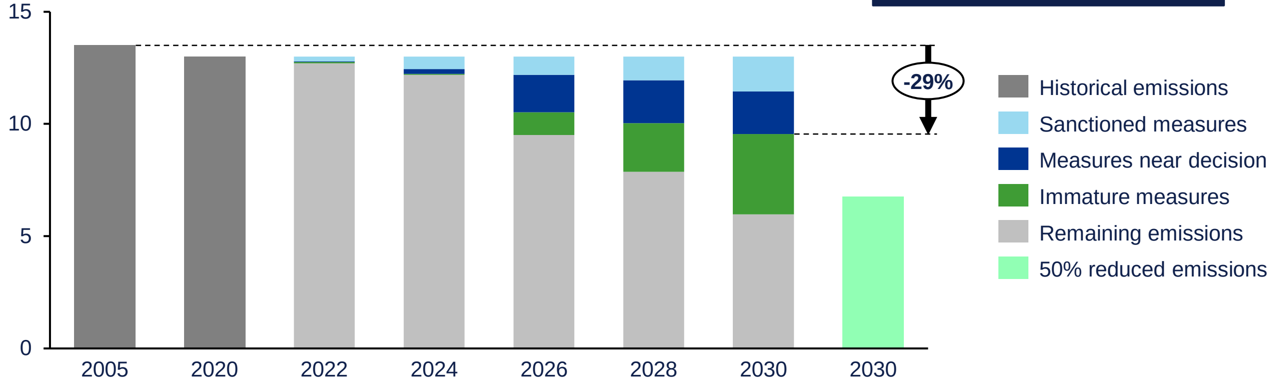
- DNV is striving in this project to gather and project GHG emission data on the NCS and onshore facilities. Key elements to display are:
  - GHG emissions per field
  - Projected production (till end of field)
  - Carbon reduction initiatives: implemented, planned, sanctioned.
  - Net realistic estimated GHG emissions in 2030
- However the data sources are not consistent, partly due to proprietary information and the decisions regarding new decarbonization projects are not easily available (decision process ongoing).
- **Worth mentioning is that of the 50+ registered fields, 8 of them represented 50% of total GHG emission in 2020. Without significant emissions reductions of these fields, the GHG targets are almost impossible to achieve.**

Historical and forecasted emissions on the NCS and onshore facilities

[million tonnes CO_2eq per year]

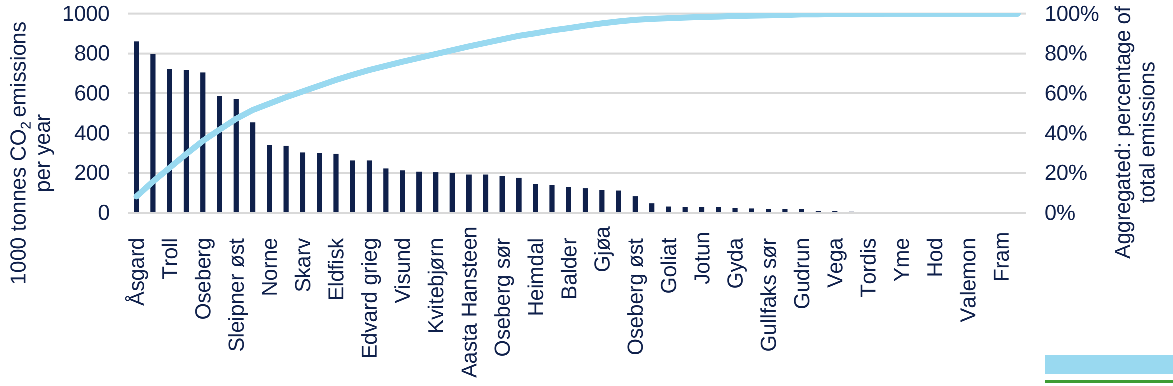
Source: NPD (2021)

Note: DNV working on making an updated forecast for this study



Annual and aggregated CO_2 emissions for fields on the NCS (2020)

Source: Miljødirektoratet (2020)



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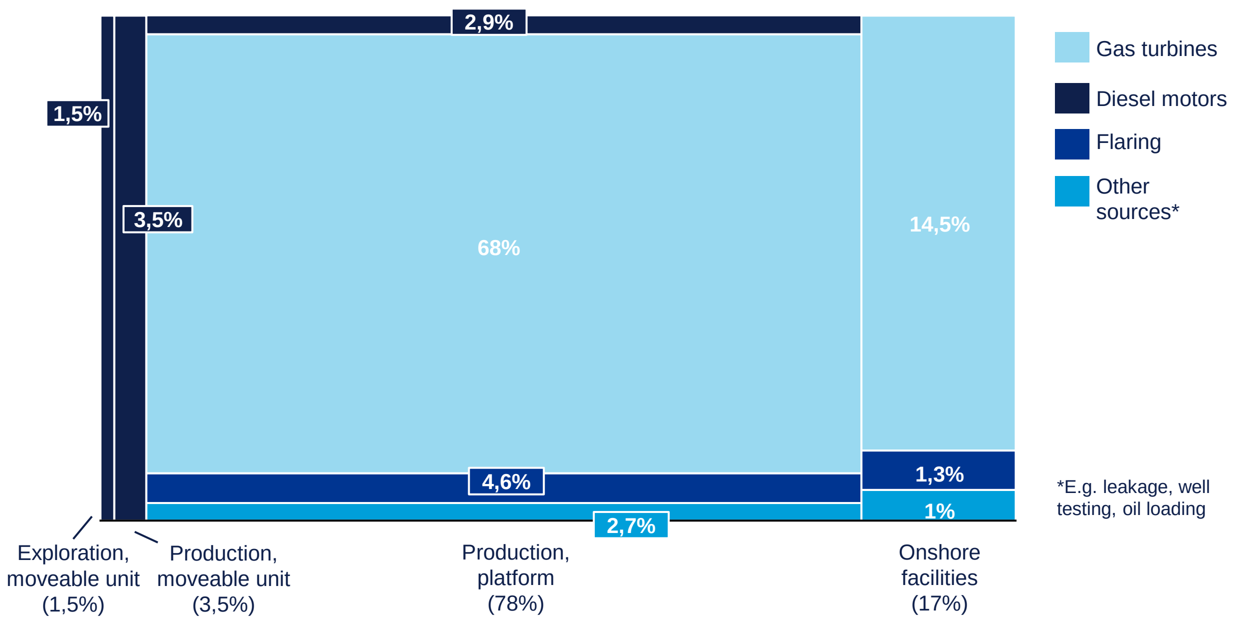
Turbines account for around 83% of total scope 1 emissions on the NCS

- The chart to the right outlines the total scope 1 emissions from the NCS (including onshore activities) in 2019, categorised into activities and emission sources.
- **Activity:** In 2019, around 78% of total scope 1 emissions occurred from platforms on producing fields, while 17% occurred during onshore activities.
- **Emission sources:** Fuel combustion in gas turbines is by far the largest source of emissions, with 83% of total scope 1 emissions coming from these turbines in 2019 (68% from platforms and 15% from onshore activities).

Scope 1 emissions from the NCS in 2019, by emission source and activity

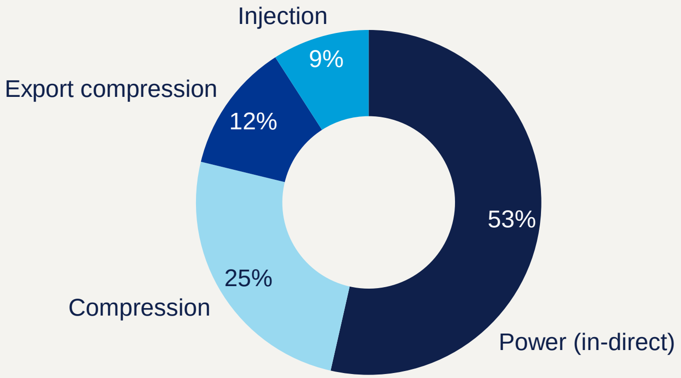
[% of total Mt CO_2-eq emitted]

Source: SSB, figure inspired by Rystad (2019)



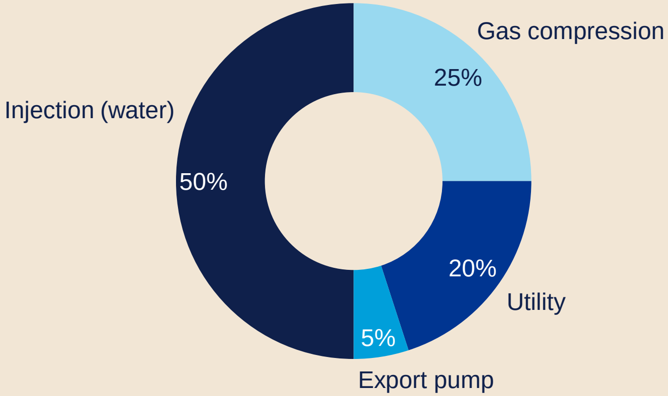
The turbine related emissions vary from gas and oil fields

GAS FIELDS



- More than 50% of the normal turbine load is related to power generation to be used for utility, compression or injection.
- These power generator turbines can be more easily replaced with electric power, known as part-electrification. Replacing the turbines driving compressors and pumps requires more extensive modifications on existing platforms, and is more expensive.
- Processing gas also requires some heat, which can be generated from waste heat from the gas turbines. A full electrification would require installing electrical heaters [1].

OIL FIELDS

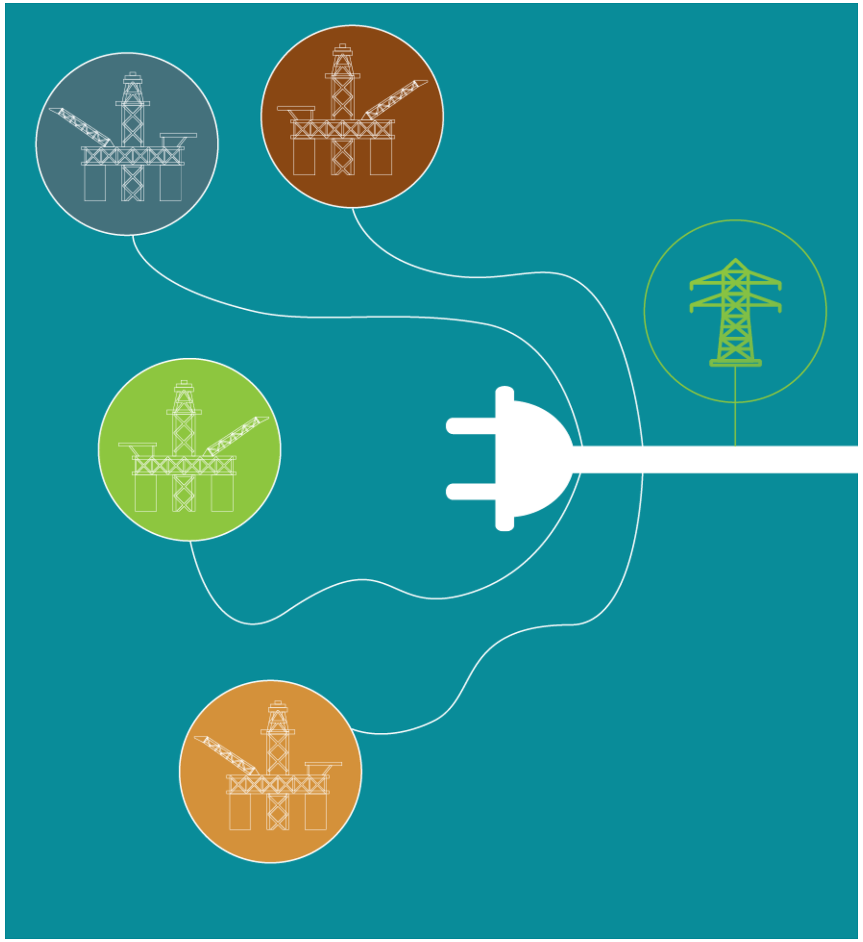


- On typical oil fields, water injection is the most energy intensive operation. This shows a large potential for reducing the energy demand for this process to reduce emissions.
- Gas compression for transport is the second largest energy intensive operation, and together with water injection this accounts for around 75% of gas turbine emissions from oil fields.
- The emissions from gas turbines vary depending on the energy efficiency [1].

1) Rystad (2019)

Several technologies can be used to replace gas turbines

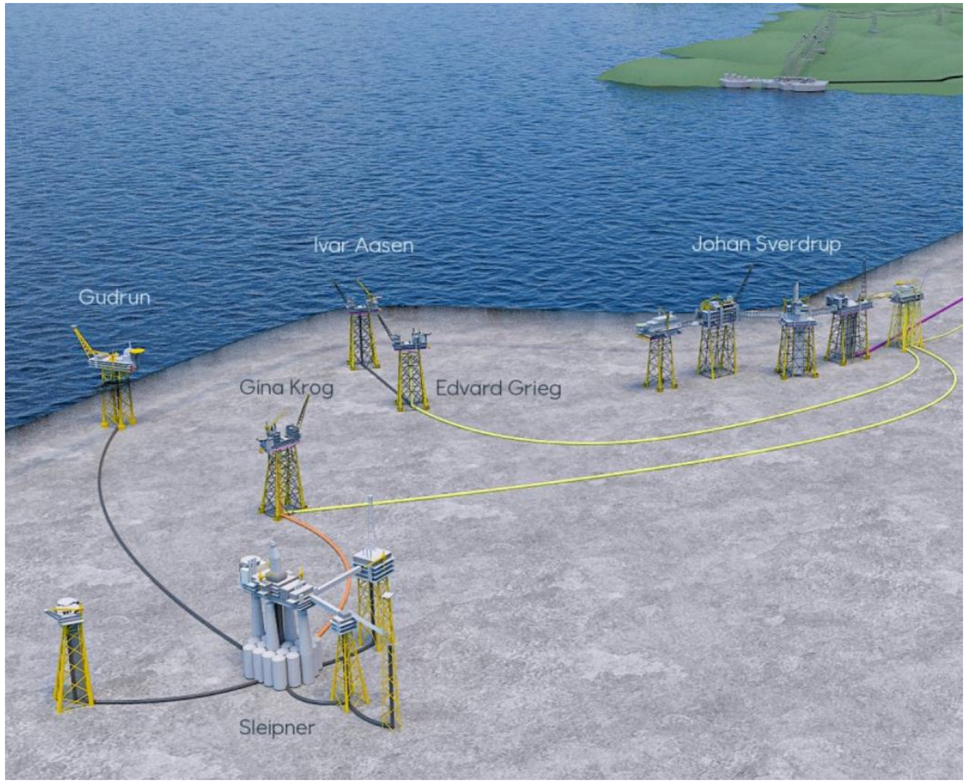
- As seen in the previous slides, the main measure for reducing scope 1 emissions on the NCS and from onshore facilities is by reducing emissions from gas turbines. This can be done through several measures, such as:
  - Electrification measures, either from shore, from power hubs offshore, or directly from offshore wind
  - Measures involving CCS, such as centralized power hubs or decentralized top-side
  - Gas turbines running on alternative, low-carbon fuels
- Another way of reducing the emissions from gas turbines is by reducing the energy demand or optimise the gas turbines.
- Electrification from shore is seen as the main opportunity for reducing emissions towards 2030, but recent developments have sparked the debate on whether the NCS should be electrified from shore.



Electrification

The debate on NCS electrification

- Electrification of the NCS has long been considered as crucial and a self evident measure that needs to be taken in order to reach Norway's 2030 climate goals
  - If Norway is to stand by its target to cut inland emissions by 55% by 2030, electrifying the O&G sector is still the easiest way to facilitate this.
- With increasing electricity prices, extensive electrification plans, the war in Ukraine and little new electricity production in the pipeline a new debate on how the available electricity is best employed has emerged:
  - Where will the available electricity give the most value from a societal perspective?
  - What long term outlook do the projects that use the limited electric resources have?
    - Lifetime of electrification projects matter
- The political debate crosses traditional party lines

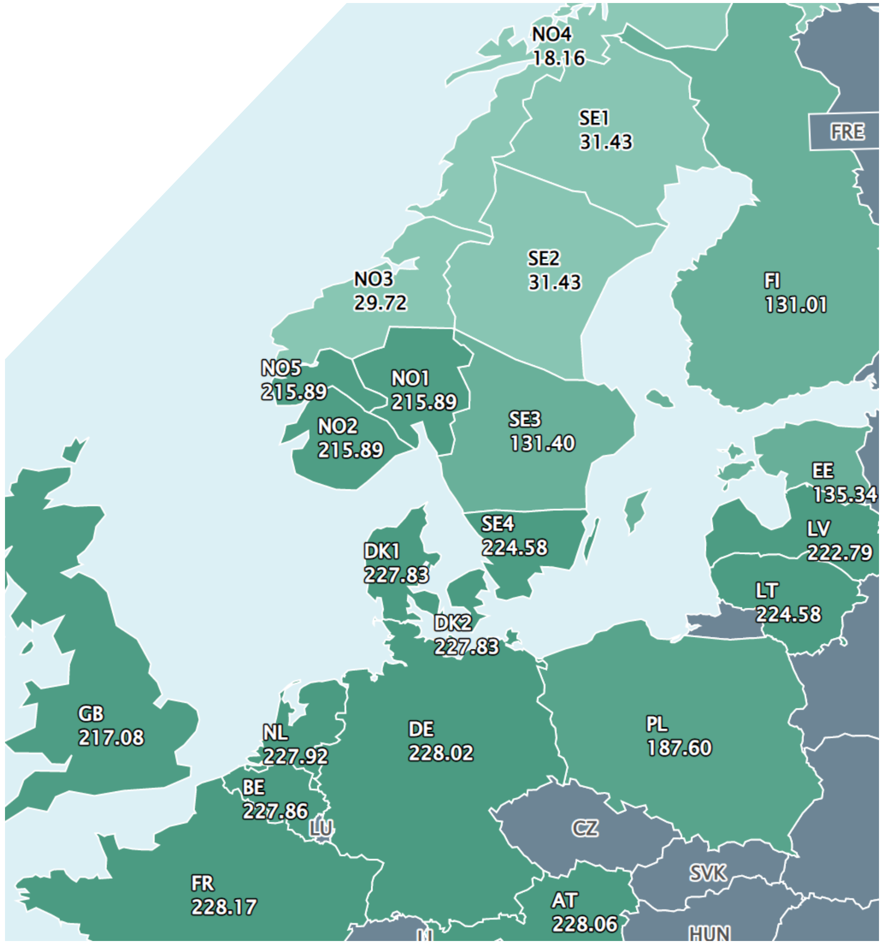


Electrification of Utsirahøyden, Equinor

Electrification

European and Norwegian Power Market overview

- The European and Norwegian electricity markets are in constant development
  - Stricter 2030 climate goals and higher CO2 prices
  - Uncertain and volatile gas and CO2-prices due to the war in Ukraine and other political developments
  - A lot of new offshore wind and hydrogen production expected in Europe as technology prices are coming down
  - All in all, this gives higher and more volatile power prices across Europe
- In Norway, electrification trends are expected to dominate in the next 5-10 years, but new production capacity is not keeping up
  - ETO Norway, Statnett and NVE all predict that the Norwegian power surplus will be significantly reduced or diminished some time between 2025 and 2030.
    - New generation capacity is temporarily coming to a halt and will be limited to what is already under construction. After 2030 it will pick up again with more offshore and onshore wind projects being realised. There is also some potential for solar PV
    - Four sectors are expected to drive the increase in demand: Industry, transport, oil and gas production and hydrogen production. How much is electrificated will vary with prices and increased production capacity
  - Looking ahead, today's price level in Southern n Norway will likely subside with higher reservoir levels. Somewhat lower prices than in Europe are expected
  - However, higher and more volatile price levels are expected over the coming years. Domestic price differences are also likely to continue



Hourly power price (19-20, NOK) in Europe, 28th April 2022. Nordpool

Electrification

Norwegian Power market predictions

Statnett

Statnett has recently published a long-term market analysis (2020-2050) with a December 2021 update, and a short term market analysis (2021-2026). The reports predict little new power production before the end of this decade beyond what is currently being built.

On the demand side, the requests Statnett has received for connections point to increasing certainty about new demand connecting to the grid. All in all, this gives a development where a power surplus of 15 TWh in 2021 is reduced to 3 TWh in 2026 before it increases again after 2030. Electricity demand in the petroleum sector is expected to grow from 9,5 TWh in 2020 to 20 TWh in 2030.

Average power prices are expected to follow a "high scenario" development as of December 2021. An increase is expected especially towards 2025 before they fall somewhat to 2030. The price increases are expected to be lower in Northern and mid-Norway and that European influence will give more power trade and volatility.

NVE

NVE's long term market analysis (2021-2040) point to how access to sufficient grid capacity, production and power prices will have a considerable influence on how much the demand for new electricity increases. They particularly highlight the transport, petroleum and industrial sectors, whilst hydrogen production also can make a significant impact if realised.

On the production side, NVE includes Solar PV to a larger extent in their predictions than Statnett, but have similar views on both onshore and offshore wind being realised from 2030 onwards. In their basis scenario they predict a reduction in the Norwegian power surplus from 20 to 7 TWh towards 2030.

Similar to Statnett, the power demand in the petroleum sector is expected to be roughly 20 TWh. They also point to how electrification of the petroleum sector is resulting in significant grid investments around the country.

They also put emphasis on how Norwegian power prices are strongly affected by renewable expansion and technology developments in continental Europe and the access to surplus power production in the Nordics.

ETO

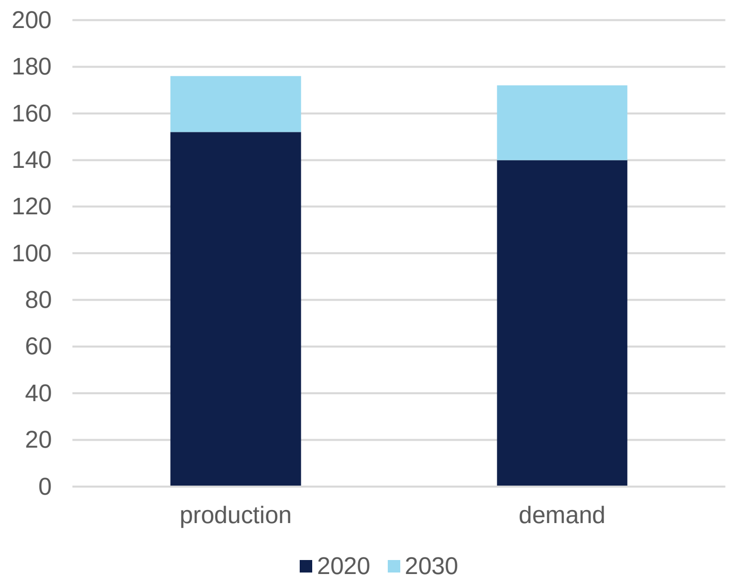
DNV's Energy Transition Outlook towards 2050 forecasts that households, service industries, as well as the electrification of transport, will consume the existing Norwegian electricity surplus. This will lead to a deficit of domestic electricity supply for further decarbonization plans as well as new industrial growth within sectors such as battery factories, green steel, alumina and electrolysis-based hydrogen production.

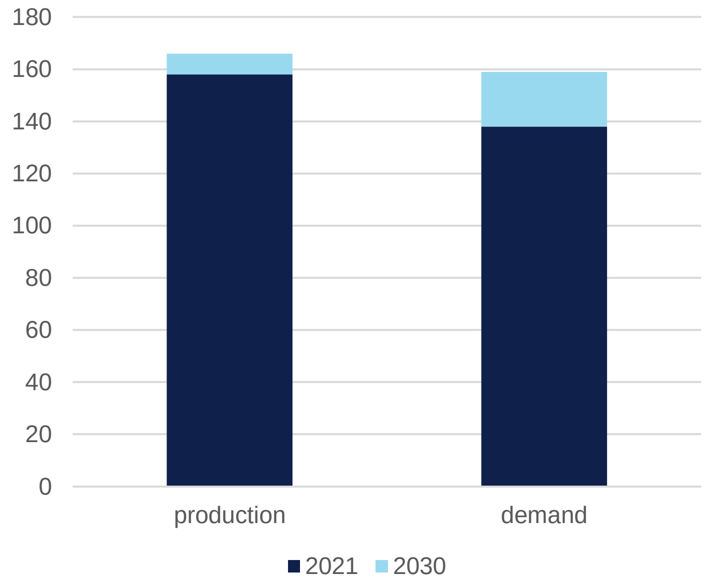
On the production side, new hydropower capacity is limited and onshore wind is facing increased public resistance. Offshore wind is then the technology that can increase power production the most going forward, although the lead time for these projects are long.

To supply the Norwegian Continental Shelf (NCS) with electricity while simultaneously supporting green industrial growth, Norway must likely import electricity for several years between 2025-2035. Increased reliance and exposure to European power prices can cause volatility as well as potentially higher prices – reducing the competitive advantage of low-priced green electricity needed for industrial production. The ETO therefore forecasts severe challenges in juggling ambitions of electricity surplus, reducing emissions as well as supporting industrial growth before significant volumes of offshore wind is connected to the grid towards 2035.

Electrification

Statnett and NVE forecasts





Comments

- Both forecasts give surplus numbers in 2030 that can easily be diminished if hydropower production is lower than expected or demand increases more than expected.
- Note that NVE's numbers are based on 2021, considerable wind power was connected to the grid over the last year
- Other differences in production is mainly related to when new offshore wind is connected to the grid
- NVE has slightly lower estimates of new electricity demand, this is mostly related to onshore industry expansion

The Statnett forecast gives a 2020 surplus of 15 TWh and 4 TWh in 2030. Demand increases from 140 TWh in 2020 to 172 TWh in 2030, whilst production only increases from 152 TWh in 2020 to 176 TWh in 2030.

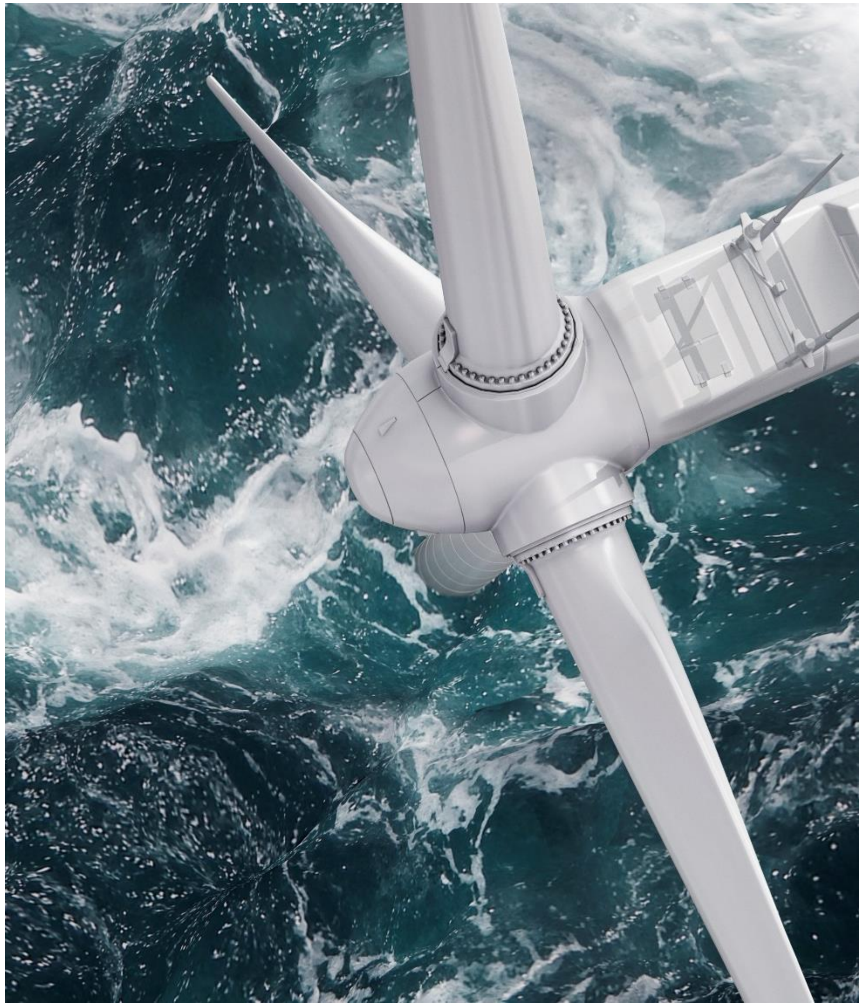
Based on Statnett's 2020-2050 Long term Analysis, with small update in dec 2021

The NVE forecast gives a statistical 2021 surplus of 20 TWh and 7 TWh in 2030. Production will grow from 158 TWh in 2021 to 166 TWh in 2030, and consumption will grow from 138 TWh in 2021 to 159 TWh in 2030

Based on NVE's 2021-2040 Long term Analysis

Electrification

What elements will influence the electrification of the NCS?



1. Statnett is the Norwegian TSO responsible for operation and development of the Norwegian Transmission grid. They have an **obligation to connect customers to the grid if they ask for it**.
   - However, the customer has to pay for any necessary grid expansions
   - Any new major grid investment project also need to receive a licence from the government in order to be realised
2. A lot of **new electricity demand is expected** in the coming years. In some sectors demand is growing rapidly already with great momentum.
   - This especially applies to the transport sector which is an important sector to decarbonise, with considerable political support
3. For other sectors, **grid reinforcements, new production capacity and power prices** will have a considerable influence on how much the demand for new electricity increases.
   - This applies to all sectors with growing electricity demand, including the petroleum sector
4. The degree to which battery factories, other (power intensive) industry and hydrogen production develop projects in Norway will **influence the debate on how extensively the NCS can be electrified**.
   - More new industry = more competition for scarce resources = higher prices and potential public and political resistance
5. For NCS-electrification projects, it could be relevant **where the O&G platforms connect to the grid**
   - North/south price differences
6. If NCS-electrification projects can show that they have concrete plans to connect to or **cooperate with new renewable/decarbonisation industries** such as offshore wind, hydrogen production, CCS etc, this will extend the lifetime of the O&G platforms, giving less climate risk and extending the lifetime of the platforms.
   - Electrifying platforms that will only be profitable for a finite period of time can give lower total value than onshore projects
7. **Higher CO_2-prices** gives economic incentives for more electrification, but can also make alternative solutions more viable

Content

Assessing GHG emission reduction potential

For each technology, the GHG emission reduction potential is assessed against the baseline, based on the technical GHG emission reduction potential as well as the application and scaling potential, as shown in the figure.

Note that the scope 3 emissions are assessed on a more qualitative level as mentioned in the approach, as quantitative and historical data is difficult to obtain. Scope 2 emissions are assessed indirectly for each technology.

For the TG workshops: We are working on building a database that can support us in evaluating the "application and scaling potential" alongside qualitative assessments per technology. This part is still work in progress. The discussions in the workshop will provide valuable information to this.

Technical GHG emission reduction potential for Scope X

% of GHG emissions reduced by replacing conventional solution with chosen technology

E.g. ***100%*** *Scope 1 GHG emission reduction by replacing gas turbines with direct electrification*

×

Baseline Scope X emissions

% of total GHG emissions today that stem from the conventional technology

E.g. ***80%*** *of Scope 1 emissions from the Norwegian petroleum industry in 2022 stem from gas turbines offshore*

×

Application and scaling potential

% of conventional technology that could theoretically be replaced by chosen technology, if fully scaled

E.g. ***40%*** *of gas turbines offshore could theoretically be replaced by power from offshore wind*

=

GHG emission reduction potential

The resulting GHG emission reduction potential for a given technology

Calculated: 100% x 80% x 40% = ***32%*** *of all Scope 1 emissions could be reduced by power from offshore wind*

Assessing maturity

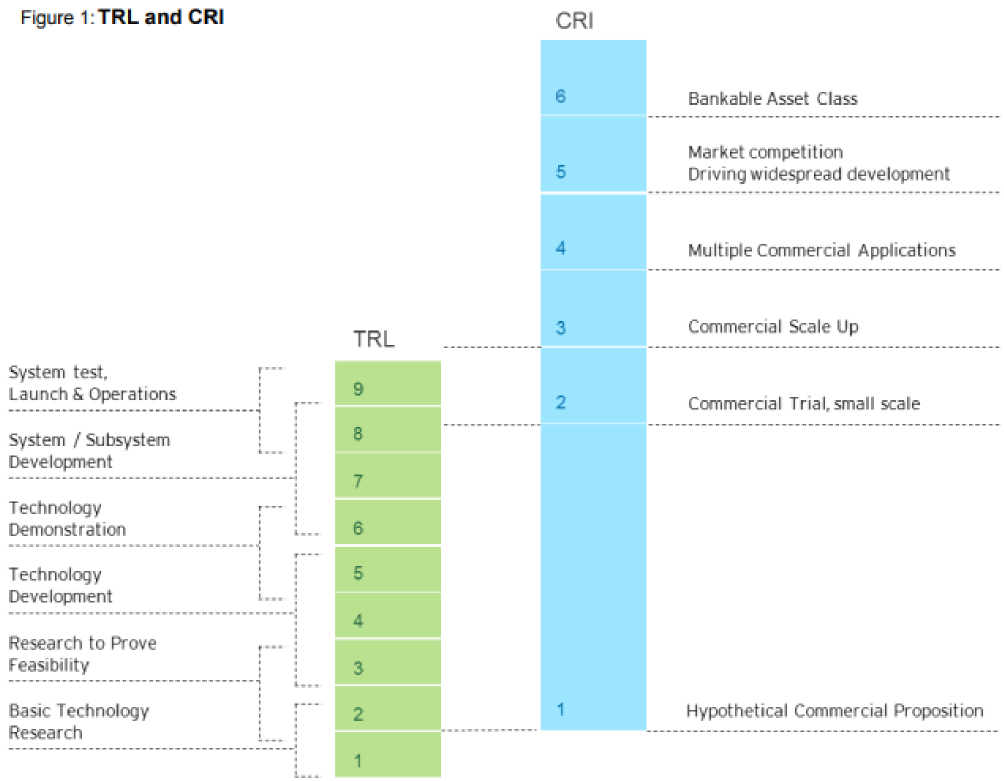
Technology and commercial readiness, and the relation between API and NASA-type TRL scale

API-scale: Technology readiness level (TRL)

Phase	TRL	Development stage
System validation	7	**Field proved** System field proved in operational environment
	6	**System installed** System installed and tested
Technology validation	5	**System tested** System/technology interface tested
	4	**Environment tested** System/technology validated in relevant environment
	3	**Prototype tested** Technology function, performance and reliability tested
Concept validation	2	**Validated concept** Experimental proof of concept
	1	**Demonstrated concept** Proof of concept as desk study or R&D experimentation
	0	**Unproven concept** Basic research and development (R&D) in papers

NASA-type: Technology readiness level (TRL) and commercial readiness index (CRI)

Source: https://arena.gov.au/assets/2014/02/Commercial-Readiness-Index.pdf



Comparing opportunities

The input from these workshops will be used to further strengthen the background information and assessment of the long-list of technologies. DNV will use this for a first take on scoring the technologies using a "high, medium, low" methodology as outlined below, based on a set of screening criteria. This will then be sent for review to OG21. Finally, the technologies will be compared and a selected short-list will be prioritised for further analysis in phase 2 of the project.

Decarbonization opportunity for Scope 1 emissions	**Application scope**	**Screening criteria**					
		GHG emission reduction potential High: >75% Medium: 45-75% Low: <45%	**Maturity** High: TRL 6-7 Medium: TRL 4-6 Low: TRL <4	**Scale-up timeline** High: Before 2030 Medium: 2030 – 2035 Low: After 2035	**Main development and implementation obstacles** High: Substantial obstacles not solvable in the short term Medium: Obstacles that are solvable in the short term Low: Limited obstacles	**Industry opportunities** High: Clear and important opportunities Medium: Possibly important opportunities, but less clear Low: Little opportunities	**Synergies with Scope 3** High: Clear and substantial scope 3 synergies Medium: Some scope 3 synergies Low: Limited scope 3 synergies
Technology 1							
Technology 2							
…							

Main focus in workshop

High	Medium	Low

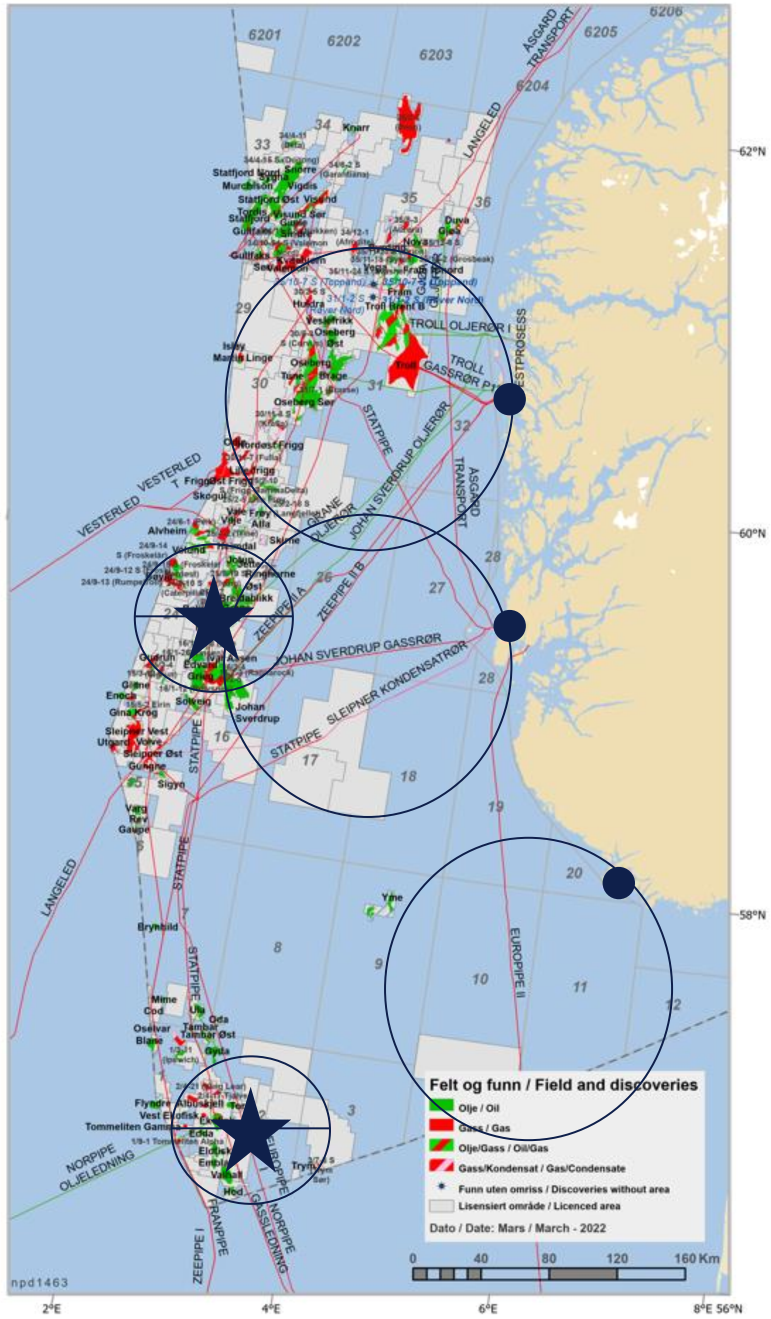
DNV

3.2 Decarbonization opportunities
Overview of (some) electrification options

- The are multiple opportunities for electrification of offshore energy consumption. These can be combined in numerous ways. As introduction, we will start with the bird's eye perspective
- Looking at a map of offshore energy consumption, there are some fundamentally different design approaches
  1. **Coordinated**: Numerous fields supplied via (some) offshore energy hubs
     - Hubs are connected to shore(s) and/or offshore wind farms etc.
  2. **Individual**: Each field supplied via direct connection to shore
  3. **Local supply**: Each field supplied from local (offshore), dedicated electricity generation source (wind and/or some thermal alternative)
- On the next pages, we will explain some generic economic and regulatory features of these designs, including why 1 and 2 essentially represent mutually exclusive alternatives while 3 can be combined with both. On the following pages, we
  - In reality, final choices are likely to be a combination of 1 for some fields and 2 for others, plus 3 for some of both designs

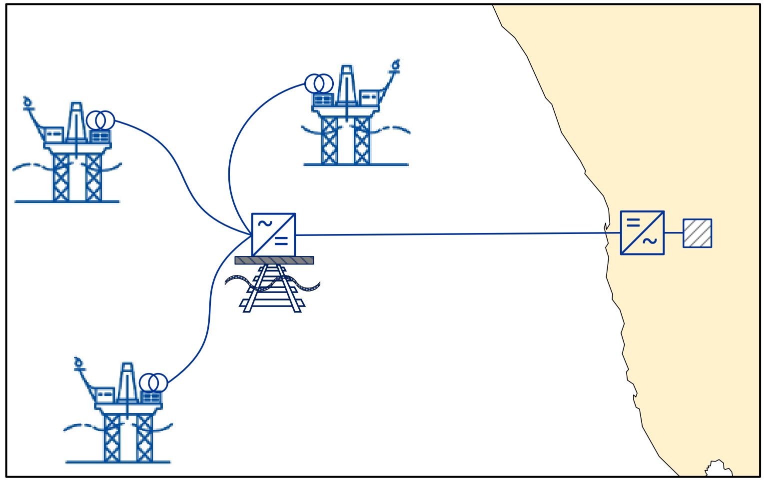
160km distance from shore (AC cables)

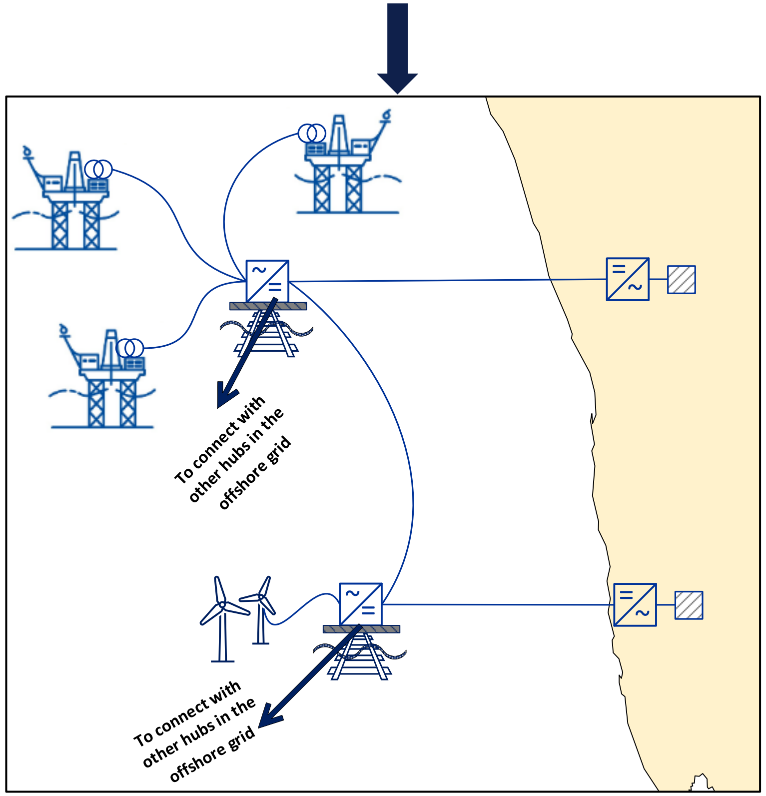
Offshore gas turbine hub



3.2 Decarbonization opportunities
Overview of (some) electrification options (2)

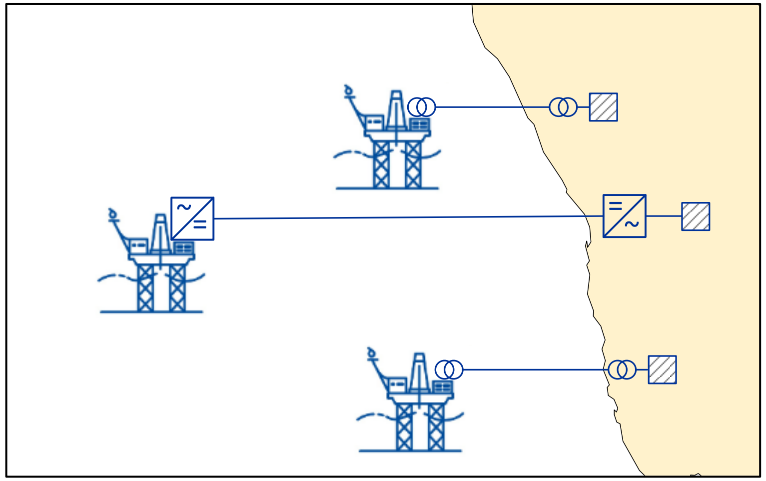
- **1 – Coordinated approach: Multiple fields supplied via offshore hub(s)**
- Johan Sverdrup (phase 2) is a good example of this type of solution
  - A large connection to the onshore network, combined with smaller connections to the individual platforms
    - Could alternatively be connected to other offshore hubs, energy islands, large offshore wind farms, etc.
    - Connections to shore will typically be DC, while the local offshore connectors will be AC or DC depending on distance and power
- To electrify ‘everything’ along the coast, one would need some such connections to shore and/or to other energy hubs
  - The resulting network design will have some similarities with the meshed onshore network
  - Eventually, the network design can evolve into a truly meshed network over time, and integrate with the meshed offshore grid in the North Sea for offshore wind integration.
- This type of solution requires significant coordination of stakeholders (primarily licensees/operators) and represent complex decisions and decision making procedures
- The key benefits are significant economies of scale, both in terms of investments and in terms of regulatory processes, potential for higher security of supply at lower costs, and potential for fewer conflicting interests





3.2 Decarbonization opportunities
Overview of (some) electrification options (3)

- **2 – Individual approach: Unique onshore connection for each field**
- Most of the existing power from shore projects (Goliat, Gjøa, Martin Linge) are examples of this approach
  - Individual connections tailored to each field/platform.
- To electrify 'everything' along the coast, one would need a large number of such radial connections to shore
  - The resulting network design will simply be a large number of radial connections, in some regions connected to the same point onshore
  - Choice between AC and DC depends largely on distance and power
- This approach does not require the same amount of coordinated decision making, and is likely if there is no (or insufficient) coordination. Individual decisions are complex, but less than for the coordinated approach
- The key benefit is the lower complexity in decision making
- The disadvantages are significantly higher (investments) costs, higher costs to ensure N-1 supply, more regulatory processes related to connections to shore, and larger scope for conflicting interests (environmental, use of areas, local on-shore network issues)

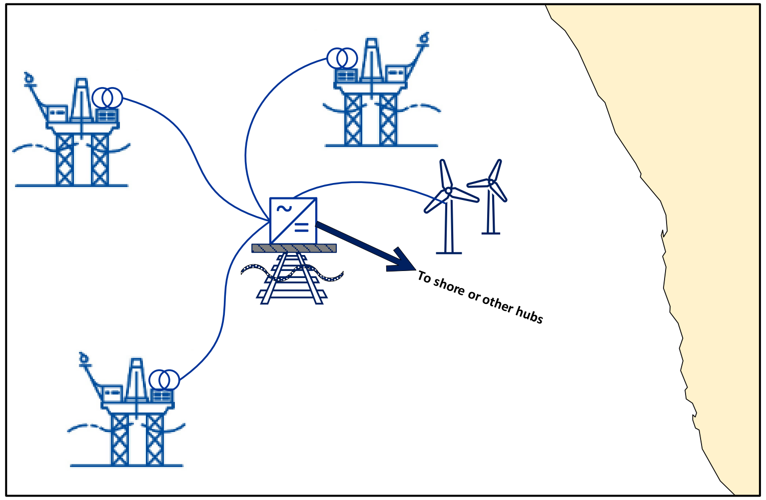


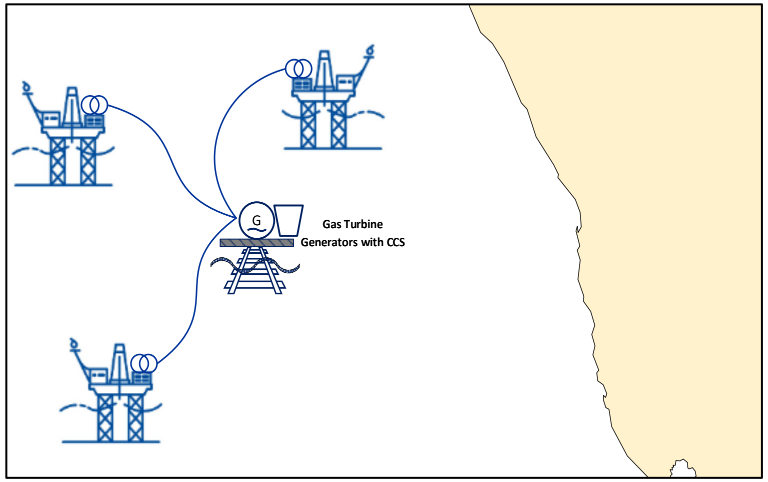
AC or DC?

- **Historically the HVAC technology was used when the distance to shore is lower than 200 km:**
  - \+ Mature technology
  - \+ Lower footprint on platform
  - \+ Higher losses
  - \- Power rating limited by cable rating (< 200 MW per project)
  - \- Normally require complicated reactive compensation onshore (SVC or STATCOM plus shunt reactors)
  - \- Need Frequency Converter to supply 60 Hz platforms
- **HVDC was used with distance longer than 200 km:**
  - \+ Lower loss
  - \+ Distance and power rating not limited
  - \+ Providing support to onshore AC grids
  - \+ Supplying 50 Hz or 60 Hz platform equally well
  - \- Technology still under development
  - \- Large footprint on platform (HVDC converter)

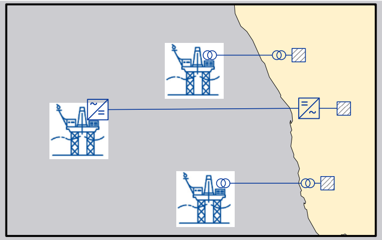
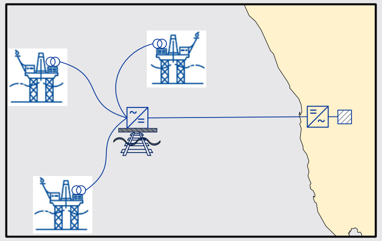
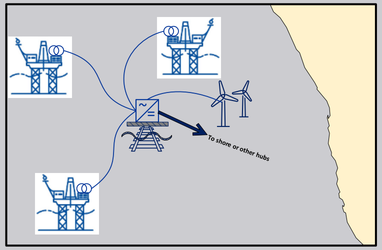
3.2 Decarbonization opportunities
Overview of (some) electrification options (3)

- **3 – Local supply: Dedicated local supply to each field (wind and/or thermal alternatives)**
- Both the coordinated design and the individual solutions can be combined with a supply of locally generated electricity. A local solution does not require a connection to shore or other hubs at all, and is thus also an independent alternative
- The complexity and the decision making process depend on each case
- In combination with a coordinated or individual connection to shore, is can ensure N-1 supply
- Potentially attractive if there is significant distance to shore or other hubs





Summary of different electrification options

OSW Connection Concept	Description	Illustrative Figure
Individual	Each plarform is connected to the onshore grid via a dedicated radial connection, which can be either HVAC (for distances to onshore POI up to 180 km) or HVDC for distances over 200 km. Note this design relies on (i) the capacity of the interconnector cable from the platform to shore (maximum capacity to e.g. 400 MW HVAC or 1,200 MW HVDC), and (ii) the hosting capacity of the point of interconnection on the onshore grid. This design offers a simplicity in design and the smallest total amount of cable laid offshore and provides the advantages of resource diversity, redundancy and associated reliability benefits.	
Coordinated	In this design, multiple platforms are connected to one offshore hub (shared substation) before being further connected to onshore grid. Note this design relies on (i) smaller OSW farms that can aggregate to a common export cable to shore (maximum capacity of that common cable limited to e.g. 400 MW HVAC or 1,200 MW HVDC) and (ii) relies on a point of interconnection on the onshore grid that can handle significant injections of energy at a shared substation. This design balances a minimized cable landfall footprint with the potential risks of limited redundancy and associated impacts to reliability.	
Local supply	Both the coordinated design and the individual solutions can be combined with a supply of locally generated electricity. A local solution does not require a connection to shore or other hubs at all, and is thus also an independent alternative. The local supply can be from the offshore wind or onboard gas turbine generators (with CCS). See following slides.	

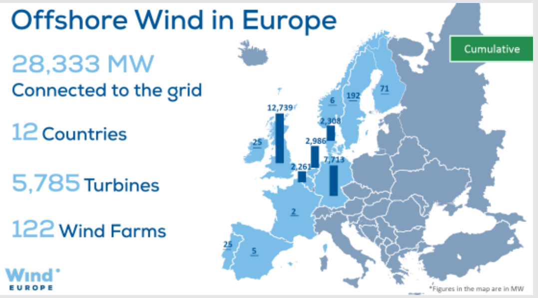
3.2 Decarbonization opportunities
Direct electrification from offshore wind

Offshore wind is at an applicable level of maturity and can be used to reduce the use of gas-fired turbines on the NCS.

Short description

Bottom fixed wind is fully commercial with over 28 GW by 2021 installed in Europe [1], but still more expensive then other energy sources. Floating wind is approaching large scale and commerciality, with only a few years before we will see the large multi unit-projects (>20 units). Innovation and developments are still needed to cut cost to make the solution competitive.

Offshore wind is a more secure source of wind energy than onshore, however, there will be variation of production due to shifting wind speed. Power from wind energy must therefor be implemented in combination with storage and/or other power sources.



Application scope and scaling potential

Application scope
- Offshore wind can replace or reduce the use of gas turbines for electrical purposes.

- Offshore wind can be a replacement of the gas turbines for water injection.

Scaling potential and timeline
Short term (2022-2030):
Within 2030 the scaling will mainly be limited by the lack of floating substations for very large deep water sites. Bottom-fixed offshore wind is fully scalable as of today.

Long term (2030-2050):
In the long term both bottom fixed and floating wind will be fully cost competitive solutions. The scalability will mainly be limited by distance from shore and conflict of interest for the most feasible nearshore areas.

Maturity
Technology Readiness Level (TRL) and Commercial Readiness Index (CRI)

Short term (2022 – 2030):
Bottom-fixed wind is a fully proven and commercial applicable with a TRL level of 7.

For floating wind the spar and semisubmersible floating concepts are currently at a TRL 6, and will within the short term of 2030 be at the highest TRL level. Other floater concepts such as barge and TLP has a lower TRL of 5 and 3 respectively, but is also expected to be at a high TRL level within short term.

New application area requires learning and developments of the full system integration. In WIN WIN the complete water injection by offshore wind system was given a TRL 4 [2].

Long term (2030 – 2050):
Floating wind is expected to be commercialized within the long term perspective of 2030-2050 with the highest TRL level, and will during this period increase the CRI to 5/6.

Accelerating developments
Technical developments of dynamic cables and power integration with the platforms or a park.

1) Wind Europe, Offshore wind energy 2021 statistics, March 2022
2) DNV, WIN WIN Joint Industry Project: Wind-Powered water injection, May 2019

3.2 Decarbonization opportunities
Direct electrification from offshore wind

GHG reduction potential

Target emission sources
Offshore wind solutions can reduce the use of, or be a part of a replacement of the gas-fired turbines for power production at the NCS. The Norwegian Petroleum organization reports that 85% of the CO_2 emissions connected to the petroleum industry in Norway is due to turbines [1].

53% of the emissions can be cut by replacing the gas-fired turbines for electrical purpose, and 9% through water injection.

Technical reduction potential
With a sufficient storage solution it is technically possible to reduce the emissions from the gas turbines by 100% with offshore wind, however, offshore wind alone cannot replace the gas turbine due to the variable power supply.

Realistic reduction potential
The realistic reduction of GHG depends on the site and the capacity of offshore wind and the infrastructure on the platform. Equinor reports that with Hywind Tampen with a capacity of 88 MW is estimated to reduce 35% of the annual electricity power demand of the five Snorre A and B, and Gullfaks A, B and C platforms, and offsetting 200,000 tonnes of CO2 emissions and 1,000 tonnes of NOx emissions per year [2].

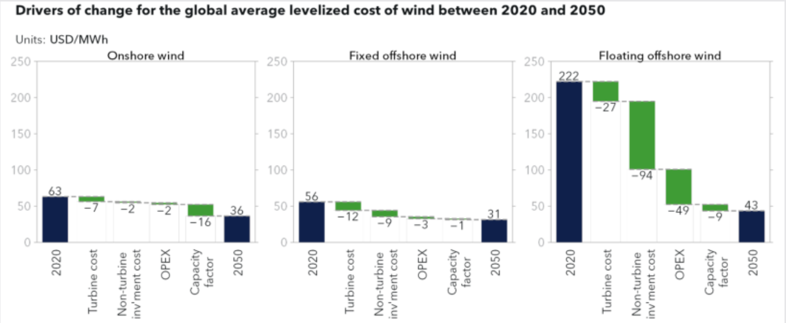
Main challenges and opportunities

Development and implementation obstacles
The biggest issue with regards to offshore wind is the variable/intermittent power delivery. Offshore wind is namely dependent on the inconsistent source of wind. To secure a steady energy source it is dependent on either storage solutions or another power supply.

The offshore wind floater technology is ready, however, still some technological gaps on dynamic cables, power integration, and offshore substations are yet to close.

In Norway, the industry suffer under the absence of political commitment. It is not clear for the developers which regulations to follow, or what will be the upcoming requirements.

One of the other main challenges is the cost. The solutions are there, however, the cost of especially floating wind is not yet competitive in the power market. DNV predicts that the LCOE of offshore wind will be 31 USD/MWh for bottom fixed and 43 USD/MWh for floating in 2050 [3]. These reduction is expected to be driven through investment and large-scale projects.



Industry opportunities and synergies
Europe has a bold offshore wind target of 60GW by 2030 and 300 GW by 2050 [4]. Development and upskilling of the Norwegian industry and supply chain will be highly valuable in the European market, but the knowledge is fully transferable worldwide.

At the end of the lifetime of the platform the offshore wind can be scaled up and/or connected either to the Norwegian inland, or connect to the a export cable selling and supporting Europe with their energy need. The offshore wind units can also be used for production of alternative fuels or as an offshore charging station. For floating wind there is also a focus on movable units, making the production flexible and directly able to sell or reuse the floater at another location.

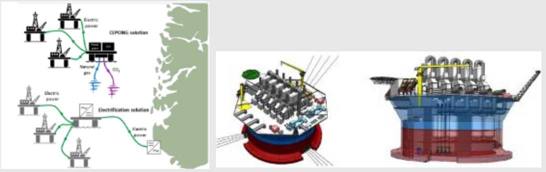
1) Norsk petroleum, https://www.norskpetroleum.no/miljo-og-teknologi/utslipp-til-luft/, August 2021
2) Equinor, https://www.equinor.com/energy/hywind-tampen, August 2019
3) DNV, Energy Transition Outlook, 2021
4) offshoreWIND.biz, https://www.offshorewind.biz/2022/02/16/eu-streamlining-path-to-300-gw-by-2050-offshore-wind-target/, February 2022

3.2 Decarbonization opportunities
Gas power hubs offshore with CCS, serving the NCS

Gas turbines on platforms in addition to land-based gas turbines are the largest upstream and midstream CO2 emitters (scope 1). One technical solution for reducing these emissions is through electrification via a central gas power hub offshore with CCS. Compared to a onshore power plant with CCS serving the NCS, such a solution could provide a potential for a cost efficient solution as it e.g., provides an opportunity to utilise otherwise non-commercial natural gas, possible use of existing infrastructure, reduce avoid transport of natural gas and CO2 over long distances etc.

Short description

- The offshore power plant could be based on a combined cycle configuration, including multiple gas turbines and steam turbines, utilising the gas turbine exhaust waste heat in Heat Recovery Steam Generators [1].
- The CO2 capture technology could be based on the most mature capture technology involving amine based solvents, or other more novel capture technology.
- The location of the power hub should be based on a optimised CCS value chain, both in terms of cost and technical feasibility. This implies taking into account both cost and technical feasibility of the CO2 transport and – storage.
- The location also need to depend on the potential for CO2 reduction, i.e., number and/or size of the installation that can be electrified from the power hub.



Clean Electricity Production from Offshore Natural Gas (CEPONG) concept, [1]

Application scope and scaling potential

Application scope
A power hub offshore should be assessed in relation to electrification from shore in terms of application. Hence, replacing gas turbines offshore directly by providing sufficient power through electricity.

Scaling potential and timeline
Short term (2022-2030):
- Development of a offshore power hub would require a timeline beyond 2030. Hence, the potential of CO2 reduction from this measure could not be expected on a short term.

Long term (2030-2050):
- On a longer term the offshore power hub could have a huge potential, but location of such hubs and the following CO2 reduction potential is difficult to assess. In a study by SINTEF [1] the concept of offshore power hubs with CCS is assessed to have a CO2 reduction potential of 90% (based on capture ration for mature solvents).

Maturity
Technology Readiness Level (TRL) and Commercial Readiness Index (CRI)

Short term (2022 – 2030):
- Capture technology TRL 5 (applied onshore, but not offshore)
- CO2 transport: Flexible pipelines TRL 5
- CO2 transport by ship: offshore loading/offloading systems TRL 2-3

Long term (2030 – 2050):
- Capture technology TRL 7 (dependent on technology development)

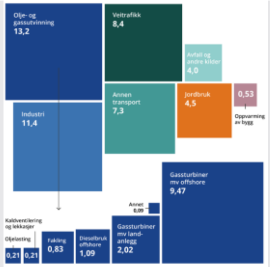
Accelerating developments
Develop accessible CO2 storage infrastructure – including CO2 shipping if transport will be based on shipping.
Explore models to connect with existing CO2 storage projects such as Northern Lights (NO) and/or others.

[1] Roussanaly, S., et al, 2018, *Offshore power generation with carbon capture and storage to decarbonise mainland electricity and offshore oil and gas installations: A techno-economic analysis*, CEPONG project (Climit)

3.2 Decarbonization opportunities
Gas power hubs offshore with CCS, serving the NCS

GHG reduction potential

Target emission sources
The source is a gas turbine in open cycle or combined cycle mode. These are Scope 1 emissions. Considering a total (2020) upstream and midstream CO_2 emissions of 13.2 Mt CO2 turbines on platforms make 72% (i.e. ~9,5 Mt) and turbines on-shore make 16% (~2 Mt) of that [1]. Gas turbines are applied for power generation (simple cycle, combined cycle or cogeneration), or for gas compression (transport) and (water) injection.



Technical reduction potential
Based on current technology one could assume a capture rate between 80-90% from the gas turbine exhaust gas (dependent on optimal configuration offshore), hence also representing the CO2 reduction potential from turbine emissions at a offshore gas power hub. One would also gain a higher electrical efficiency in such a hub-system compared to single turbines on platform that often is operated on part-load. To realise this potential a fully developed value chain for transport and storage of the CO2 is required.

CCS is commercially proven and there are a number of successfully CCS project such as Sleipner and Snøhvit (Norway) and Quest (Canada). CCS can be scaled depending on the volume of CO2 to be stored. CO2 can be stored in either saline aquifers or depleted fields

Realistic reduction potential
The potential for CCS related to NCS is constrained by finding suitable subsurface storage complexes within economic transport distances of the offshore gas power hubs.
Large scale CO2 storage derisking is required to identify exact storage sites. However, Norway has already conducted the first phase of regional storage screening of the NCS. The Norwegian CO2 storage Atlas has already high graded locations on the NCS and associated capacity estimates for the key areas. Detailed appraisal activities will further derisk these high graded areas. A combination of saline aquifers and depleted fields need to be screened, assessed and ranked versus transport distance from the offshore gas power hubs. According to the CO2 storage Atlas sufficient CO2 storage capacity exist on NCS to decarbonise gas power hubs offshore

Main challenges and opportunities

Development and implementation obstacles
Key considerations for gas power hub with CCS:
- Finding a suitable storage site: The storage complex needs to prove containment, sufficient capacity, economic rate of injection and monitorability.
- Optimised location for power hub: Need to take into account optimised cost and technical feasibility of CO2 transport and storage in addition to electrification potential of installations (e.g. distance for electricity transport and installations possibility to be electrified)
- Competitiveness of offshore gas power with CCS vs. other power hub concepts (wind, electrification from shore)
- Spatial planning: The power hub could compete with other activities as wind farms, oil & gas activities etc.
- Cost for CO2 capture technology and application of the technology in offshore conditions
- CO2 spec and required polishing for transport and injection purposes (material integrity)
- If ship transport: Offshore loading/offloading technology
- Opportunities to benefit from the CCS value chain developed for other CCS projects (common storage site for other sources)
- Opportunities for reuse of existing infrastructure

Industry opportunities and synergies

- Additional CO2 source for Northern Lights phase 2 (5 MTPA) [2]
- Open up more storage locations for potential cross border CO2 storage
- Further cements Norway leading edge as a Global Leader in CCS activities
- Develop the Norwegian CCS supply chain

[1] Miljødirektoratet; Klimagassutslipp fra olje- og gassutvinning (miljodirektoratet.no)

[2] https://ccsnorway.com/app/uploads/sites/6/2020/07/Plan-for-long-term-use-of-the-Northern-Lights-infrastructure-1.pdf

3.2 Decarbonization opportunities
Compact topside CCS

Gas turbines on platforms in addition to land-based gas turbines are the largest upstream and midstream CO2 emitters (scope 1). One technical solution for reducing these emissions is through CO2 capture and storage directly at the installation. Being limited due to weight and volume constraints on the platform capture technology will need lighter and smaller units than the ones used onshore. However, developments are progressing and the first commercial products for offshore applications are recently made available on the market. Availability of feasible CO2 storage is the major bottleneck.

Short description

- A carbon capture system removes the CO2 from the flue gas of the gas turbines and produce a concentrated CO2 stream that can be sent to geological storage.
- CO_2 capture systems can be design to remove up to 95% of the CO2 produced by the gas turbine. Up to date there are no operating capture systems on gas turbines, although this is technically feasible.
- New and existing offshore installations might allow limited weight and volume additions when it comes to including or retrofitting CO2 capture systems. Floating platforms need special designs to account of motion effects.
- Tailored CO2 capture systems optimized for offshore applications are being developed, including systems designed for floating applications (i.e. FPSO).
- Aker Carbon Capture has recently presented versions of their technology specifically tailored for FPSO applications [1]. This system is based on well-known solvent-based capture processes.
- There are technologies under development that could provide a higher level of compactness and better capture efficiencies. Relevant examples are the systems developed by Compact Carbon Capture and Net-Power but they are currently developed for onshore applications.

Application scope and scaling potential

Application scope

- It would be platform specific, not all brown field platforms can be retrofitted for capture or have access to CO2 storage at feasible distance.
- CO2 storage might be constrained by location of suitable site nearby the platform.
- Volume of CO2 captured is about 4 kt/y for each MWe installed (a 30 MW GT corresponds to about 120 kt/y captured).
- Scope for this option will depend on a full cost benefit analysis of the whole capture, transport and storage value chain

Scaling potential and timeline

Capture technologies are technically mature and commercially available – they can be retrofitted on existing installation if there are no space and load limitations. Bottleneck is the access to qualified CO2 storage sites, it takes at least 5 years to develop a CO2 storage site (depleted field), it can be longer for an aquifer – all depends on data availability. Before 2030 it is likely that only a few projects could succeed. Afterwards, a more developed CCS infrastructure and lower cost could results in greater pick up. Potential in long term after 2040 could be limited by the increasing public pressure on closing down fossil fuel operations and a decreased need in oil&gas as a result of the energy transition.

Maturity

Technology Readiness Level (TRL) and Commercial Readiness Index (CRI)

Short term (2022 – 2030):
Capture systems for offshore applications not subjected to motion have a TRL of 5/6, depending on technology provider – the technology is available and proven but there are no operating commercial version yet in offshore environment. Systems for floating platforms or FPSO, that are subjected to motion have not been implemented, meaning a slightly lower TRL of 4 even though some vendors already offer them on the market.

Long term (2030 – 2050):
TRL of 7 is expected for solvent based capture processes, for fixed or floating applications. New technologies will likely reach TRL 5/6 in this timeframe and are likely to become commercial.

Accelerating developments

- Develop accessible CO2 storage infrastructure (Clusters / Hubs style development) – including CO2 shipping if transport will be based on shipping.
- Explore models to connect with existing CO2 storage projects such as Northern Lights (NO) and/or others.

[1] Just Catch™ Offshore – Aker Carbon Capture

3.2 Decarbonization opportunities
Compact topside CCS

GHG reduction potential

Target emission sources
All O&G platforms, including floating ones and FPSOs, where power is supplied by a gas turbine installed on site.

Technical reduction potential
Solvent-based CO2 capture processes are typically designed for removal of 90% of the CO2 contained in the flue gas as this is the considered the soft spot to optimize capture rate vs costs. However, the capture rate is a design parameters and can be changed as desired. Higher capture rates like 95% is feasible although it requires more efficient (bigger) equipment and therefore comes at higher cost. A capture rate of 99% is theoretically feasible but requires an equipment size that is probably too big in dimensions for offshore applications and too costly.

Realistic reduction potential
The realistic reduction potential for a CO2 capture system based on solvents is 90-95% of the gas turbine emissions. The potential for NCS is dependent on the limitations on brownfield assets when it comes to space and weight and the need for rebuild. Also, as stated for the gas power hub with CCS solution, availability of suitable storage site will impact significantly to the actual potential for this technology.

Main challenges and opportunities

Development and implementation obstacles
- Capture – not all brownfield platforms can be retro-fitted for CO2 capture, due to space and weight constraints in existing O&G platforms.
- There needs to be a suitable CO_2 storage near by the platform, if none are available, transport via ship or pipeline to a suitable storage need to be developed.
- Technical challenges CO_2 Storage: each individual store needs to prove containment, sufficient capacity, economic rate of injection and monitorability. In addition, the storage activity could compete with other activities such as wind farms, oil & gas activities etc.
- Cost vs volume of CO_2 per installation: this option is likely more expensive than having centralised gas power hubs with CCS, mainly due to the economies of scale associated with a larger CO2 stream to store vs a low volume stream per individual platform. Requires full cost benefit analysis

Industry opportunities and synergies
- The range of gas turbines models and sizes employed in offshore applications is rather restricted (i.e. M2500+G4, SGT750, LM6000), allowing easier modularization of CO_2 capture systems for offshore applications. This has benefit for costs reductions as well as for engineering and implementation.
- Gas turbines used in offshore applications are typically open cycle – this means that it many cases it is possible to recover waste heat from the GT exhaust to produce steam to run the CO_2 capture process (if solvent based). Although this means a higher CAPEX upfront, it has a significant advantage on the operating costs as one of the major requirements of the CO_2 capture system is related to the energy supply (e.g. steam supply).
- Platforms located in the same area, with relative small distance between them, could possibly use a common storage site and a transport infrastructure. This could have significant benefit for the cost and time required to implementing CCS.

Differing risk profiles of Saline aquifers vs. Depleted fields

Risk factor	Deep saline aquifers	Depleted fields
Containment **- Well** **- Faults & seal**	• Typically fewer legacy wells – primary anthropengic leakage path	• Typically higher density of legacy wells, as the field has been explored developed and produced
	• Faults and seals not geomechanically weakened through production - but depending on the distance from O&G fields are untested	• Due to depletion of HC, fields are geomechanically compromised • Proven in the local area to hold HC
Capacity	• Regional capacity ranges typically higher • Larger uncertainty range on capacity estimates prior to appraisal actives, linked to limited data on reservoirs (store) properties	• Typically offer smaller overall capacity, as the capacity is limited to the field size • Uncertainty on capacity range less, due to better reservoir (Store) knowledge – fields are data rich environments compared to saline saline aquifers
Injectivity	• Greater uncertainty due to lack of data, cannot be derisked until appraisal well conduct injectivity / production test(s)	• Production data gives you confidence on dynamic injectivity rates early on in CCS storage maturation phase • Depending on the amount of depletion, you may not be able to inject initially in a supercritical phase until the store is pressured to within the pressure envelope of supercritcal phase injection. • Alternately add additional heating and compression at the well head to protect the near well bore environment - injected CO2 wills still freely move, expand and cool rapidly (J-T cooling). These thermal effects can impact frac pressure of the store without careful management.
Monitorability	• Geophysical monitoring techniques inside of outside the store and the storage complex are not hampered by the presence of residual HC	• If residual HC remain, especially gas, they can inhibited geophysical (seismic) techniques aimed at visualizing plume migration with the confines of the structurally defined ''store' (injection reservoir) unit. However, it does not preclude the use of seismic outside for detecting CO2 leakage or migration outside the defined store or storage
Other (HSSE and Appraisal costs)	• HSSE case simpler - no simultaneous operations occur if an aquifer is developed from a greenfield platform – only fluid on the platform is CO2 • Potentially higher derisking costs – likely to require additional appraisal activities (wells, seismic, geo technical studies etc..) prior to FID	• Likely more complex HSSE case, if a brownfield platform is reused, a dual safety case is required for both CO2 and HC being present on the platform • Depending on the number of legacy wells and state of abandonment – higher abandonment cost could occur prior to 1st injection – but limited appraisal cost as fields are data rich and unlikely to need to prove economica rates of injection due to wealth of HC production data.

Decarbonization opportunities
Hydrogen and hydrogen-derived fuels for power production

Gas turbines on platforms in addition to land-based gas turbines are the largest upstream and midstream CO2 emitters (scope 1). One technical solution for reducing these emissions is by replacing natural gas by hydrogen or ammonia. Combustion of low calorific gaseous fuels in gas turbines is not unusual in the refining and steel making industries (e.g. blast furnace gas). In those cases the gases arising from these processes are considered as waste gases. Firing hydrogen in gas turbines for fully commercial reasons, depends on the attractiveness of the various power markets or power needs (island-operation).

Short description

- Gas turbines are used land-based and on platforms.
- Gas turbines are a reliable technology for power generation and mechanical (compression) or marine drives.
- They are available in sizes from micro scale (tens to kilowatts) to very large scale (hundreds of megawatts). The newest medium to large sized simple cycle turbine models range between 5 and 600 MW. The most common one in NCS is 25 MW (LM2500)
- Traditionally these gas turbines fire natural gas as a primary fuel. Companies like General Electric, Kawasaki and Mitsubishi Power have gas turbines in their portfolio that are designed for low calorific process waste gases (steel industry, refineries).
- The main identifiers for gas turbines are their operating window, ramp rates, power output, heat rate, minimum load and (NOx) emissions. This is particularly true for gas turbines that have a dual fuel combustion system or allow for various process fuel gases from industrial sources.
- When firing hydrogen or ammonia, the consequences for gas turbine design are depending on type, operating profile, combustion system (premix/non-premix) and co-firing ratio..

Application scope and scaling potential

Application scope
Hydrogen firing in new gas turbines or in refurbished gas turbines. Various options;

- Co-firing of H2 with none or limited modifications (e.g 30% vol)
- Co-firing of H2 with burner modifications or replacement (tbd)
- Conversion of natural gas to H2 of existing gas turbines
- Replacing existing gas turbines by new bespoke ones

Scaling potential and timeline
Short term (2022-2030):

- Existing : 30%-50% by volume (10%-15% by energy)
- New : 100% from 2025-2030 onwards (limited load variations)
- In the short term only hydrogen, no significant ammonia

Long term (2030-2050):

- 100% hydrogen is feasible
- NOx emissions are point of attention as well as load variations
- Ammonia more likely for specific turbines with bespoke technologies (e.g. Mitsubishi has research ongoing)

Maturity
Technology Readiness Level (TRL) and Commercial Readiness Index (CRI)

Short term (2022 – 2030):
Current state of the art is 30% H2 by volume which is ~10% by energy (TRL9, CRI3). A multitude of installations that are equipped for hydrogen co-firing are expected for the next few years (TRL10, CR14) with OEMs offerings available. Currently OEMs are developing combustors for high percentages co-firing (current TRL7) which are expected be first commercial at scale somewhere around 2025 (TRL8, CR13). The direct co-firing of ammonia has undergone testing programs (TRL4, CR11), while real prototyping at scale (TRL5) is not expected before 2025. A 100% ammonia in gas turbines is an immature technology (TRL3).

Long term (2030 – 2050):
New turbines that are specifically designed for 100% hydrogen with low NOx emission levels are likely to be included in OEMs offerings by the end of the 20s/beginning of the 30s (TRL9).. Development of turbines on direct combustion of ammonia is not the focus of today, but may come into play in the 30s.

Accelerating developments
The uptake will strongly depend on the market conditions, incentives or specific local drivers.

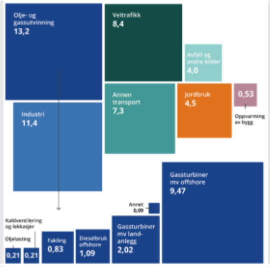
Decarbonization opportunities

Hydrogen and hydrogen-derived fuels for power production

GHG reduction potential

Target emission sources

The source is a gas turbine in open cycle or combined cycle mode. These are Scope 1 emissions. Considering a total (2020) upstream and midstream CO_2 emissions of 13.2 Mt CO2 turbines on platforms make 72% (i.e. ~9.5 Mt) and turbines on-shore make 16% (~2 Mt) of that. Gas turbines are applied for power generation (simple cycle, combined cycle or cogeneration), or for gas compression (transport) and (water) injection.



Technical reduction potential

Currently, it is technically feasible to replace natural gas by hydrogen at volumetric rates in the range of 30%-50% depending on turbine type/manufacturer. The timelines for achieving these amounts in individual turbines are project specific as they relate to the need of specific fuels stations, storages, changes in settings and controls, and environmental (permitting) changes. Specific 100% hydrogen turbines (or upgrades) are under development and will be turbine specific. For the near term (until 2030) it is fair to say that based on this analogy the potential is 30%-50% across the full fleet in case all turbines could implement hydrogen co-firing. This is 10%-15% by energy and subsequently the theoretical reduction of CO_2 emissions is around 1-2 Mt.

Realistic reduction potential

In practice there are various obstacles most notably the available hydrogen infrastructures for platforms and potential impacts on permits for land-based gas turbines. Also the current activities have been executed for a number of turbine models. Eventually, one could assume that the realistic potential as part of the technical potential is in the order of 10%-50%. This then leads to a realistic reduction potential of 200 kt to 1 Mt until 2030. Market conditions, particularly the price of hydrogen compared to gas+CO_2 cost, has a big impact on the economic viability this potential.

Main challenges and opportunities

Development and implementation obstacles

Key considerations for co-firing of hydrogen:

- Cost competitiveness of hydrogen vs natural gas as fuel
- Hydrogen fuel station / storage causing specific safety measures
- For platforms, the need for mooring barges for fuelling
- The tendency for increasing NOx emissions, and as such measures needed to be compliant for NOx regulations and permitting. Water injection is a remediation option. Demin water required.
- The heat rate (or efficiency) is strongly dependent on the turbine load, and varies typically between 30% and 40% depending on load. This ultimately impacts the cost of electricity
- Societal opinion on hydrogen is generally favorable, however, combustion is likely seen as the last resort
- Need for reliability and redundancy is to be considered. Combustion dynamics and flashback are key research items (for high^% co-firing and fluctuating load).
- The minimum load level and risk of flashback
- For ammonia: flame extinction and long flames need redesign for higher % co-firing
- The volumetric calorific value of H2 is three times as low as that of natural gas

Industry opportunities and synergies

- Next to green hydrogen, initially we may see also blue hydrogen with CCS, combined with combustion in gas turbines
- Lessons can be learnt from IGGC developments in the past
- Research on flexibility in operations between hydrogen and natural gas in a dual fuel combustor
- Ammonia cracking (indirect use of ammonia). The current cracking capacity is however still very limited: facilities have an ammonia cracking capacity typically in the range of 1-2 ton/day.
- For (specific) new generation GTs hydrogen capabilities (e.g. co-firing or 100%) may become the standard post-2030.
- Synergies may be found with industries that have gas fired boilers or hydrogen facilities (SMR)
- DNV sees interest for co-firing hydrogen or ammonia from utilities on islands relying on gas-fired power plants

3.2 Decarbonization opportunities
Water management: Reservoir management

Water-flooding is a widely used technique for pressure maintenance or improving sweep efficiency. Incremental recovery of water-flooding ranges from 15 to 25%. Nonetheless, water-flooding is an energy-intensive activity. Water injection systems typically consume 30 to 50% of field total power consumption. For many oilfields on the Norwegian Continental Shelf (NCS), the percentage is much higher, where more than half of the energy on a platform goes to water injection pumps. Thus, water-flooding significantly contributes to the amount of GHG emission.

Short description

Energy efficiency
Upstream CO2 emissions (NCS) per boe increases over the lifetime of the fields on the Norwegian continental shelf. CO_2 emission due to oil production depends strongly on water-cut. This is driven by more efforts required to extract latephase barrels. Emissions stems from generation of power, heat and flaring.

It is possible to lower CO2 footprint significantly by ensuring stable displacement with optimized mobility ratio for increased sweep efficiency. Further, by controlling water-cut in producing wells. Technologies include:

- Near-wellbore treatment to shut off water - biopolymer
- Viscos flooding/ polymer flooding.

Reduction of tail-end production period can reduce the CO_2-footprint considerably.

Application scope and scaling potential

Application scope
All producing oil fields on the NCS.
Considerable potential for tail-end productions.
Cost benefit for high water cut production will be needed.

Scaling potential and timeline

Short term (2022-2030):
The technologies are available, but at a high cost.
More than 50% reduction in NCS-CO2 emission – at the cost of 10 % lost oil from high-water-producing fields (*).

Long term (2030-2050):

Maturity
Technology Readiness Level (TRL) and Commercial Readiness Index (CRI)

Short term (2022 – 2030):
Water management has been widely applied and technologies for mobilisation optimisation has been matured and applied for decades. Forskningsrådet (*) gives the following TRLs;
Drainage optimisation TRL 3
Injectivity enhancement TRL 2
Alternative drainage fluids TRL 2
Smart wells TRL 2
(These TRLs seems low)

Long term (2030 – 2050):

Accelerating developments
R&D to reduce costs for water stabilising technologies, e.g. biopolymer, polymer

(*) Reference; Arne Stavland, NORCE, Rystad, Forskningsrådet; Reduksjon av klimagassutslippene fra olje-og gassproduksjon på norsk sokken med 50% innen 2030

3.2 Decarbonization opportunities

CO2 –EOR: Energy efficiency through reservoir management

CO_2 for EOR stands out as a technology that reduces CO_2-emissions substantially whilst increasing petroleum volumes, but it comes with a considerable cost and with a long lead time until improved recovery is realized. On the NCS the availability of CO_2 has been limited. The transportation distance and cost is a limiting factor. CO_2-EOR could be developed in connection with CCS hubs.

Short description

CO_2 Enhance oil recovery (CO_2-EOR) – Using CO_2 as a form of secondary or tertiary (after waterflooding) oil recovery mechanism. The primary goal is to improve oil recovery, it is not long-term storage of CO_2. However some CO_2 is stored in the process.

CO_2-EOR has been commercially deployed for decades, but largely onshore.

When CO_2 is injected it is back produced along with reservoir fluids, separated at the surface, and commonly, reinjected/recycled back into the reservoir. The cycle repeats throughout the operation. Max 30 % of CO_2 is trapped through residual, solubility and structural trapping over the life time of project (Hosseininoosheri et al., 2018 Permain Basin Analogue USA).

If the remainder of the recycled CO_2 can be injected into the fields after oil project has finished – additional CO_2 can be stored. Overall the CO_2 mass balance calculations increase if the remaining CO_2 left after final oil production can be safety and permanently reinjected and stored in the depleted oil field.

CO_2-EOR extends the life of existing infrastructure and maximise production in a mature Hydrocarbon basins, where exploration cost may be increases and success rates are lowering

Application scope and scaling potential

Application scope
CO_2-EOR has been commercially deployed for decades, but largely onshore. CO_2 EOR does occur offshore Brazil (Petrobras - Lulu field 2011)

On the NCS the availability of CO_2 has been limited. The transporation distance and cost is a limiting factor.

Scaling potential and timeline
Short term (2022-2030): Scaling and deployment is linked to suitable reservoirs for CO_2 EOR and supply of CO_2
Key challenges – high CAPEX and OPEX cost of conducting CO_2-EOR offshore

Long term (2030-2050):
Linked to finial incentives and ability to lowering CAPEX and OPEX cost of conducting CO_2-EOR offshore

Maturity

Technology Readiness Level (TRL) and Commercial Readiness Index (CRI)

Short term (2022 – 2030):
TRL – mature
CRI – low
NPD screened 23 oil fields on NCS for CO_2-EOR would improve oil recovery between 4-12% (Lindeberg et al., 2017)

Long term (2030 – 2050):
- Develop CO_2-EOR in connection with CCS hubs

Accelerating developments

- **45 Q style finial incentives for CO-EOR**
- **Cost-sharing of CO_2 pipeline networks**
- Smart and cost efficient topside solutions for processing CO_2-rich fluids, subsea technologies for separation and injection of CO_2, as well as solutions for improved mobility

3.2 Decarbonization opportunities
Reservoir management: CO2 EOR and water management

GHG reduction potential
Target emission sources Water management technologies can be implemented relatively fast, but with a considerable cost. CO2 for EOR stands out as a technology that reduces CO2-emissions substantially whilst increasing petroleum volumes, but it comes with a considerable cost and with a long lead time until improved recovery is realized. The emission reduction considered comes from generation of power, heat and flaring. There is a need for continued efforts to develop and apply methods and technologies for improved subsurface understanding.
Technical reduction potential CO2-EOR; Hard to identify update information – latest data found 2017 Pure CCS will store more CO2 than CO2 EOR (CCUS) Tail-end production with high water cut; CO2 reduction from late life wells can be considerable. This needs to be assessed.
Realistic reduction potential Most promise on large fields where it is economically beneficial to do CO2 EOR.

Main challenges and opportunities
Development and implementation obstacles Cost: • High costs for water displacement technologies. • Hgh CAPEX and OPEX cost of conducting CO2-EOR offshore • Significant investment in pipeline, topside and well cost are required Technical: • Identifying suitable large scale reservoirs for CO2 EOR and supply of CO2 at low cost Availability of CO2 and transportation costs
Industry opportunities and synergies ▪ 45 Q style finial incentives for CO-EOR ▪ Cost-sharing of CO2 pipeline networks ▪ Smart and cost efficient topside solutions for processing CO2-rich fluids, subsea technologies for separation and injection of CO2, as well as solutions for improved mobility ▪ Develop CO2-EOR in cooperation with CCS hubs

3.2 Decarbonization opportunities
Artificial intelligence: asset / reservoir management

Machine learning and (data management) are the two main sub division of artificial intelligence (AI) science). The aim of ML is to speed up complex decision making and create more efficient planning. Potentially saving time money and likely emissions.

Short description

Machine learning – computers systems learn from and interpret data without human input.
Digitalisation – complying physical data in an easy to use digital that can easily accessed and used

ML - be applied to well trajectory planning (Ability to generate multiple well paths faster to provide different options to decision makers), portfolio planning, rig sequence management, decommission planning to reduce OPEX. Additional many attempts have been applied to seismic interpretation to speed up exploration prosect identification.

Digitization – faster access to data to improve techanical workflow

All major oil companies e.g. Shell, BP, Equinor have departments dedicated to finding new and innovative ways to speed up decision macking to reduce cost

Application scope and scaling potential

Application scope
Most value in oil & gas planning activates where there are competing options and ML can provide multiple scenarios for planners and decision makers to choose between

Digitalisation of data can significantly speed up the delivery of subsurface (e.g. model building, development planning) and engineering workflows

Equinor technology strategy 2019 predicted
Automated drilling – 15% cost reduction
Future fields – 30% capex reduction & 50% opex reduction

DNV GL 2020 estimates: Drilling cost reduction; 3-4 bNOK/year ▪ GHG reduction of 0.06 Mega ton, representing 6% of drilling activities release (1.06 Mega ton)

Scaling potential and timeline
All major E&P companies have been investing heavily in AI for more than a decade. This is a fast developing field. Impact is still uncertain.

Maturity
Technology Readiness Level (TRL) and Commercial Readiness Index (CRI)

Short term (2022 – 2030):
Currently being applied to assest in the North Sea
All the major oil companies operating in the NCS have AI strategies e.g. Equinor, Shell etc..
The maturity of the different application varies and is hard to put a TRL level on it

Long term (2030 – 2050):
- AI – will dominate technology development for the foreseeable future
- Will be applied more widely as computer programs become more sophisticated – level of impact still uncertain (Equinor technology strategy

Accelerating developments

- E&P partner with niche IT companies and training staff to be more digitally aware
- Build trust in NL solutions
- Better QAQC of data used in AI applications

DNV

3.2 Decarbonization opportunities
Artificial intelligence: asset / reservoir management

GHG reduction potential

Target emission sources
More efficient delivery of process and technical delivery will reduce emissions directly and indirectly. Largest impact is likely on scope 1 emissions

Technical reduction potential
BCG 2021 PREDICTS : 15% could be abated economically through improvements in operational and energy efficiency – this is overall estimated, not specific to reservoir management

Realistic reduction potential
Difficult to find data on this, to be discussed.

Main challenges and opportunities

Development and implementation obstacles
(key words: technical, costs, regulatory/political/societal)

- Technical and skill set: Training staff to be more digitally aware and investing in the latest AI solutions
- Communication and data transfer between multiple IT systems
- There is lack of trust in ML models and outputs
- Diligent management of data quality is needed for ML to succeed
- Machines can not replace humans in all operations
- Impact is still uncertain

Industry opportunities and synergies

E&P companies – making smart partnerships with IT and digitisation specialists – this is currently happening

Sharing lessons learned, successful ML algorithms, case studies, etc. for accelerated learning and ML adoption - this is more likely to happen for Environmental monitoring b) Energy efficiency c) Maintenance optimization / integrity management (DNV GL OG 21 report)

Percentage of trapping mechanism during a WAG – Permian basin USA

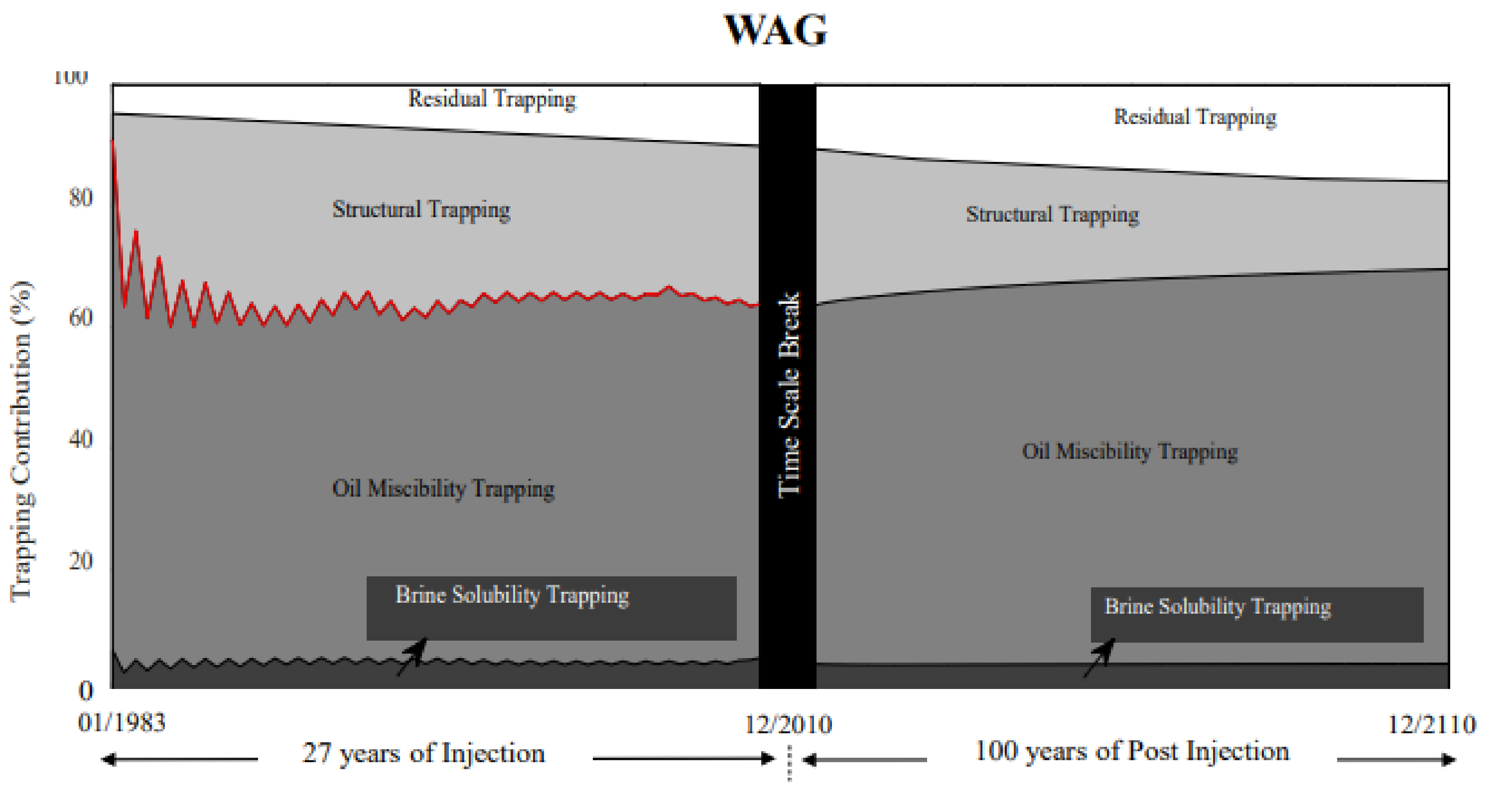


Fig. 17 - Contribution of different CO_2 trapping mechanism during injection and observation period in WAG scenario.

Source: Hosseininoosheri et al., 2018

Decarbonization opportunities
Optimized gas turbines – waste heat recovery

One approach for reducing emissions from gas turbines is to improve the total energy efficiency through waste heat recovery. The waste heat from the gas turbine can be utilised in a waste heat recovery unit (WHRU) to cover the heat demand of the installation. Alternatively the waste heat can be used to produce steam in a heat recovery steam generator (HRSG). The steam can then be used in a bottoming cycle to produce more electricity or in a steam injection gas turbine cycle (STIG).

Short description

- **Waste heat recovery unit (WHRU)** - Recovering of waste heat from the hot turbine exhaust to cover the installations heat demand and thus improving the total energy efficiency. WHRU is a proven and widely used technology.
- **Combined cycle** - The hot turbine exhaust can also be utilized in a heat recovery steam generator coupled with a steam turbine. The number of gas turbines needed to cover the power demand will be reduced enhancing the fuel utilization. However, the available heat is reduced, and the heat demand might need to be covered by other sources such as heaters. The installations specific demand heat and power will therefore influence the suitability.
- **Steam injection gas turbine cycle (STIG)** - The hot turbine exhaust can also be utilized in a heat recovery steam generator and the generated steam is injected in the combustion chamber of the gas turbine after the compressor outlet, resulting in an increased power output in the turbine whereas the compression work maintains constant and thereby improving the thermal efficiency. However, the available heat is reduced, and the heat demand might need to be covered by other sources such as heaters. The installations specific demand heat and power will therefore influence the suitability.

Application scope and scaling potential

Application scope
The solutions will improve the energy efficiency of the gas turbine system of the installation. For combined cycle it applies to gas turbines for power generation.

Scaling potential and timeline
Short term (2022-2030):

- **WHRU** – Is a proven and widely used technology. Can be implemented on a shorter term, but is probably already assessed for many installations.
- **Combined cycle** – Requires a lot of space and adds a lot of weight, so requires major upgrade for brownfield operations. Mainly considered for greenfield. Limited potential in the short term.
- **STIG** - Requires a lot of space and adds a lot of weight, so requires major upgrade for brownfield operations. Mainly considered for greenfield but still issues to solve. Limited potential short term.

Long term (2030-2050):

- **WHRU** – Same as for short term
- **Combined cycle** – On a longer term, combined cycle could have an impact in reducing emissions from gas turbines
- **STIG** – On a longer term, STIG could have an impact in reducing emissions from gas turbines, but limited compared to combined cycle.

Maturity
Technology Readiness Level (TRL) and Commercial Readiness Index (CRI)

Short term (2022 – 2030):

- **WHRU –** TRL 7
- **Combined cycle –** TRL 7 for fixed installations (Installed on Oseberg, Snorre and Eldfisk), TRL 5 for floaters
- **STIG –** TRL 5 (Only onshore applications)

Long term (2030 – 2050):

- **WHRU** – TRL 7
- **Combined cycle** – TRL 7
- **STIG –** TRL 5 / 6

Accelerating developments
For the technologies with lower TRL, demonstration in offshore applications is a means of accelerating the developments. Development of more compact solutions would also make uptake in the offshore industry more attractive.

Decarbonization opportunities
Optimized gas turbines – waste heat recovery

GHG reduction potential

Target emission sources
The source is a gas-fired turbines. These are Scope 1 emissions. Considering a total (2020) upstream and midstream CO_2 emissions of 13.2 Mt CO2 turbines on platforms make 72% (i.e. ~9,5 Mt) and turbines on-shore make 16% (~2 Mt) of that. Gas turbines are applied for power generation (simple cycle, combined cycle or cogeneration), or for gas compression (transport) and (water) injection. For combined cycle it targets gas turbines for power generation.

Technical reduction potential
- **WHRU** – The reduction potential will depend on the heat demand of the installation. But the emissions could be reduced up to 20 %.
- **Combined cycle** – The electrical efficiency will go from around 38% to 51%, which would reduce the CO_2 emissions by around 25%. However, the number would be lower depending on the heat demand.
- **STIG** - The electrical efficiency will go from around 38% to 51%, which would reduce the CO_2 emissions by around 25%. However, the number would be lower depending on the heat demand.

Realistic reduction potential
- **WHRU** – WHRU is already implemented on many installation, so this measure will have a limited additional on the emissions on NCS.
- **Combined cycle** – Could be challenging to retrofit due to space and weight challenges, so mainly valid for newbuilds.
- **STIG** - Could be challenging to retrofit due to space and weight challenges, so mainly valid for newbuilds.

Main challenges and opportunities

Development and implementation obstacles
(key words: technical, costs, safety, regulatory/political/societal)
- **WHRU** – proven and widely used technology
- **Combined cycle** – Challenges include weight and size, compared to a single cycle gas turbine both weight and footprint will roughly double. The heat demand must also be assessed as this can make the option less attractive compered to a WHRU.
- **STIG** – As for the combined cycle, the challenges include challenges include weight and size, compared to a single cycle gas turbine both weight and footprint will roughly double. In addition, large amounts of treated make-up water (boiler water quality) is needed, adding treatment facilities and storage requirements. The heat demand must also be assessed as this can make the option less attractive compered to a WHRU.

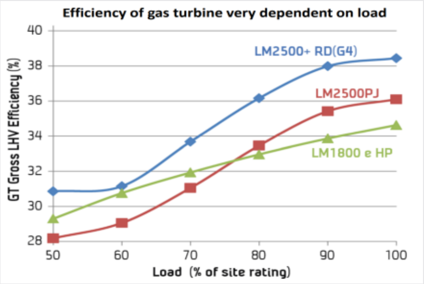
Industry opportunities and synergies
- WHRU, combined cycle and STID are already established technologies with limited opportunities for industrial development in Norway.

Decarbonization opportunities
Optimized gas turbines – utilization

Many offshore gas turbines on the NCS run at 50-60% load, some at 70-80%, leading to low efficiencies. Improving the load of the gas turbine can be done by replacing a large turbine with multiple smaller units that can be switched on and off depending on the load, another way is to add batteries to handle load fluctuations allowing the gas turbine to run on a higher load, a hybrid set-up.

Short description

- **Multiple units** – By having multiple gas turbines it is possible to better adapt to load variations while maintaining a high load factor of the individual gas turbine, i.e. being able to cut the use of a turbine instead of just reducing the load factor
- **Batteries** – Adding a battery pack can make it possible to run the gas turbine on high load over the lifetime, with additional advantages such as: (1) Battery as stand by, (2) eliminates load transients, (3) eliminates load variations. Batteries can fast deliver power to the grid, covering peaks in the demand, while base loads are served by the gas turbines.



[1]

Application scope and scaling potential

Application scope
The solutions will improve the energy efficiency of the gas turbine system of the installation through improvement of the load factor. For batteries it applies to gas turbines for power production.

Scaling potential and timeline
Short term (2022-2030):

- **Multiple units –** Readily available technology, but requires major upgrade of brownfield
- **Batteries –** Readily available technology, but with limited use in offshore applications. NCM (Nickel, Manganese, Cobalt) and LFP (Lithium Iron Phosphate) are the most common types in maritime applications. Requires space and adds weight which limits the uptake in the short for brownfield applications.

Long term (2030-2050):
The technologies are mature and commercially available and should be considered for new developments – they can be retrofitted on existing installation if there are no space and load limitations and should be considered during major upgrades.

Maturity
Technology Readiness Level (TRL) and Commercial Readiness Index (CRI)

Short term (2022 – 2030):

- **Multiple units –** TRL 7
- **Batteries –** TRL 5 (application has been tested in other marine application such as shipping, but limited use in offshore installations)

Long term (2030 – 2050):

- **Multiple units –** TRL 7
- **Batteries –** TRL 6 (Will likely be tested before 2030)

Accelerating developments
For the technologies with lower TRL, demonstration in offshore applications is a means of accelerating the developments. Development of more compact solutions would also make uptake in the offshore industry more attractive.

[1] Marit Mazzetti, OTC-24034-MS

Decarbonization opportunities
Optimized gas turbines – utilization

GHG reduction potential

Target emission sources
The source is a gas-fired turbines. These are Scope 1 emissions. Considering a total (2020) upstream and midstream CO_2 emissions of 13.2 Mt CO2 turbines on platforms make 72% (i.e. ~9,5 Mt) and turbines on-shore make 16% (~2 Mt) of that. Gas turbines are applied for power generation (simple cycle, combined cycle or cogeneration), or for gas compression (transport) and (water) injection. For batteries it targets gas turbines for power generation.

Technical reduction potential
- **Multiple units –** The reduction potential will depend on the that the gas turbine is operating on. Studies indicate that update 5% can be saved by running the gas turbines closer to full load. [1]
- **Batteries –** The reduction potential will depend on the individual load curves. Some studies indicate that 5-10% CO_2 reduction is achievable.

Realistic reduction potential
- **Multiple units** – Could be challenging to retrofit due to space and weight challenges, so mainly valid for newbuilds.
- **Batteries** – Could be implemented on different scales and for different applications. Due to weight and volume, in retrofit applications, up to 5% CO_2 reduction is probably more realistic to achieve.

Main challenges and opportunities

Development and implementation obstacles
(key words: technical, costs, safety, regulatory/political/societal)
- **Multiple units –** More turbine might require more space and more maintenance. However, if a you can cut a turbine in normal operations, availability could increase since maintenance of turbines can be done without shutting down production.
- **Batteries** – Batteries are heavy and voluminous. For example, 1 MWh of NCM battery system weighs around 10 tons (depending on detailed chemistry and packing).

Industry opportunities and synergies
- Use of batteries on NCS could create an additional user for the growing battery industry and make Norway a more attractive location for development and production of batteries and associated technology.

[1] Marit Mazzetti, OTC-24034-MS

DNV

3.2 Decarbonization opportunities
Geothermal energy to reduce electrical power demand offshore

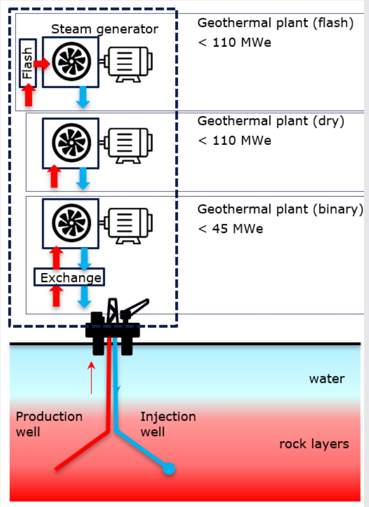
Geothermal energy can be used to generate electricity for self consumption by platforms or for third parties reducing the GHG up to 100% for that specific power production. Geothermal power is a proven technology deployed onshore with over 15 GWe in operation worldwide. It is expected that there is great potential for offshore geothermal power plants since it is possible to re-use existing or abandoned oil and gas wells and platforms. However offshore geothermal power plants is not operational at this moment and needs to be explored in the coming years to understand its potential.

Short description

A conventional geothermal system consists of two wells (production and injection well). Heat from the deep subsurface is extracted by circulating the geothermal brine in a closed loop system.

Geothermal heat can be applied for electricity production using:

1. Flash steam (>~180°C).
2. Dry steam plants.
3. Binary (~90-180°C) (ORC).



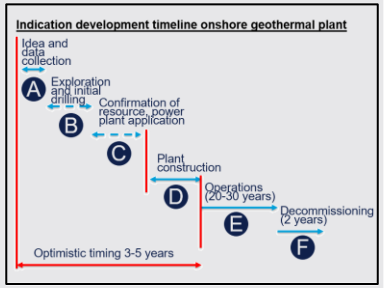
Note: In stead of a two well system, single borehole heat exchangers are available. A mono well then acts as production and injection well. First estimates on thermal output are several 100's kWth, which is considerably lower than the geothermal doublet system (of several 10's MWth)

Application scope and scaling potential

Application scope

1. Production of electricity (for self consumption or third party use).
2. Production of thermal energy for self consumption of processes at the platform.
3. Re-use abandoned well from dry oil/gas wells for geothermal energy
4. Potential coproduction of geothermal-energy from oil or gas recovery processes.

Scaling potential and timeline



- Concept Development Process for first demonstration projects
- Step B+C will be shortened by using existing geological knowledge from OG production (decrease drilling risk)

Long term (2030-2050): proven concept and working towards more standardized solutions for geothermal plants using platforms.

Maturity
Technology Readiness Level (TRL) and Commercial Readiness Index (CRI)

Short term (2022 – 2030):
Well technology : TRL9/CRI2 (onshore)
Conversion technologies (onshore):
- ORC/Rakine: TRL9/CRI2
- Flash: TRL9/CRI2
- Over 15.000 MWe realised worldwide

Offshore geothermal: TRL 4 to 6 (CRI1)

Long term (2030 – 2050):
- TRL 9-10 (CRI 2-3) concepts for offshore geothermal plants

Accelerating developments
- Cope with decarbonization requirements
- Research projects off shore geothermal energy: North Tech Energy (NTE), Transmark Renewable; SINTEF and Iceland Geosurvey (ISOR).
- Reusing wells for geothermal energy postpones well abandoned and increase well lifetimes.
- Significant lower drilling cost compared with onshore geothermal energy.

DNV

3.2 Decarbonization opportunities
Geothermal energy to reduce electrical power demand offshore

GHG reduction potential

Target emission sources

A) Providing electricity to onshore electricity grid

B) Increasing operational platform efficiency: Replacing (partial) gas turbines at platforms by geothermal power plants. Geothermal plants use some electricity to operate (e.g. ESP-pumps, cooling tower), however this can be 'geothermal – electricity' and so reduce up to 100% of the CO2 emissions.

Technical reduction potential

Potential for per geothermal power plant. Typically a

- geothermal binary technology provides 2-3 MWe [2]
- geothermal a flash or dry steam technology provides 17 tot 23 MWe [2].

Note 1) this potential for geothermal energy is based on worldwide existing geothermal plants, and has no direct relation with specific local Norwegian geothermal potential. However the ranges show a first indication of typcal power plant sizes.

Note 2) in case of "increasing operational platform efficiency' gasturbines on the platform can be replaced by geothermal electricity. For this a reference case of 80 MWe / platform could be used (4 x 20 MWe gasturbine per platform [1])

Realistic reduction potential

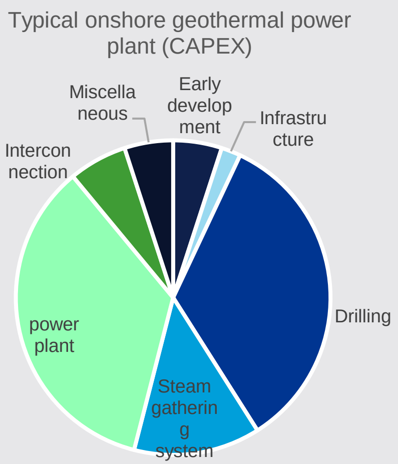
Requirements for deployment of offshore geothermal energy:

- Geological conditions and subsurface temperatures/flowrates available.
- Platform should be suitable for the construction of geothermal plant (conversion technology)
- A platform in use or close to shore for power distribution if abandoned.

Main challenges and opportunities

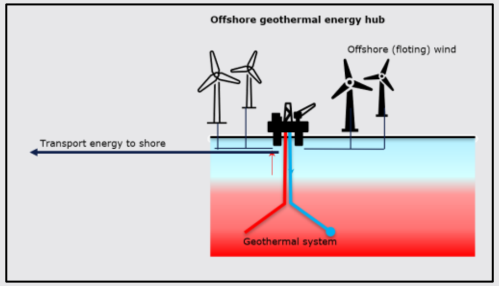
Development and implementation obstacles

1. Availability of thermal aquifer systems nearby the offshore platform with good conditions for geothermal energy (high temperature, high mass flowrates).
2. A offshore geothermal well design or repurpose OG-well (e.g. casings, insulation, well heads, tubing)
3. Cope with the harsh offshore environment (salt, current, wind, water etc.).
4. Return on investment of geothermal plant compared to platform lifecycle.
5. Subsea electricity cables needed in case of transport to shore.
6. Permits and licensing (exploration + exploitation, environmental, grid access).
7. Installation of technical room(s) at platform.
8. Low drilling cost compared to onshore geothermal plants (see picture on the right, where drilling is significant),



Industry opportunities and synergies

- Extend lifetime of wells and platforms: use existing platforms and repurpose oil/gas wells for geothermal heat/electricity.
- Provide geothermal energy for platform operation efficiency decarbonization
- Create a offshore geothermal power hub: Geothermal energy hub at sea (e.g. for H2 production, grid connection to shore, (floating)-wind turbines connected to this energy hub; local off shore geothermal electricity)



[1] Overview gas turbines Norway: https://no.wikipedia.org/wiki/Liste_over_gasskraftverk_i_Norge

[2] Calculation by DNV based on source: Efficiency of geothermal power plants: A worldwide review

Content

3.3 Scope 3 considerations

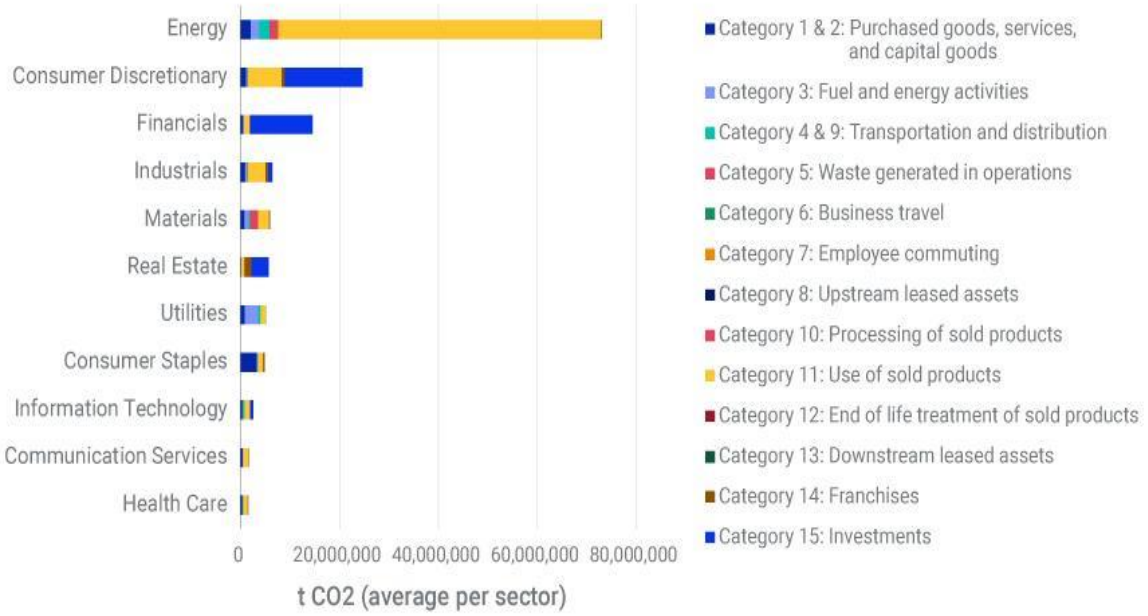
GHG protocol category overview for oil & gas – focus on category 11

Scope 3 emissions are the “result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly impacts in its value chain”. For the oil and gas sector, a majority of such emissions stem from the downstream use of sold products, and are more easily influenced if feedstock is decarbonised at point of production than point of consumption. The challenge associated with influencing the GHG emissions from end-use downstream has meant that many oil & gas companies may initially focus on influencing other scope 3 categories that are more easily influenced, for example the purchased goods and services category through supplier decarbonisation requirements.

Overview

- The GHG protocol outlines 15 categories for scope 3 emissions, of which 8 are upstream and 7 are downstream. For the oil and gas sector, around 75% of scope 3 emissions stem from downstream use of sold products (category 11) and 15% stems from upstream purchased goods and services. The remaining 10% is roughly equally divided into capital goods, upstream transportation and distribution, processing of sold products, and remaining relevant categories.
- With most of the oil and gas value chain emissions being captured in use of sold products, the most optimal value chain emission outcomes would target the decarbonization of product end-use. This would be achieved either by i) decarbonizing the feedstock prior to end-use, i.e., converting natural gas into blue hydrogen with CCS, or ii) decarbonizing the feedstock at the point of end-use, i.e., natural gas power with CCS. Oil and gas companies typically have little control over downstream emissions but could in theory sign bilateral sales agreements that would entail carbon emission abatement by the gas end-user.
- Given the challenges associated with reducing category 11 emissions, oil and gas companies also focus on categories that are easier to influence. For example, setting procurement requirements for service/goods suppliers and/or transport & distribution upstream (category 1 and 4) and transport & distribution downstream (category 9). While these are relatively smaller components of an oil and gas company’s scope 3 emissions footprint, they nonetheless can comprise a substantial volume of GHG emissions. In this way the company can demonstrate that they take action to reduce their value chain carbon footprints by influencing what they can influence. That said, category 11 comprises most of the oil and gas value chain emissions, and there are rising expectations from stakeholders that companies formulate plans to take greater responsibility for addressing these.

Estimated scope 3 emissions per category per sector



Source: MSCI

3.3 Scope 3 considerations
Corporate and national carbon budgets

There is a growing awareness that limiting global warming to 1.5 degrees will be a substantial challenge with the current rate of decarbonisation, and this will be the key backdrop to intensifying efforts globally over the coming decade. How actors respond to this narrative are likely to manifest in terms of scope 3 considerations and strategies that differs for companies and nation states, as the former typically has international GHG boundaries and the latter firmly national boundaries. As such, where oil & gas scope 3 emissions are reduced will have different intrinsic value for corporates and countries. Whereas corporates will aim to strengthen sustainability credentials and ensure long-term competitiveness, national policymakers will more likely prioritize meeting national GHG targets first.

Corporate scope 3 emissions – Increasing value and competitiveness for Norwegian oil and gas

- **Immature scope 3 reporting:** Generally, corporate scope 3 reporting is immature, with most companies not reporting on scope 3 emissions at all or at best a few scope 3 categories. This reflects the limited extent to which it has been expected that companies document their scope 3 emission footprints, both in terms of compliance reporting, as well as expectations from stakeholders.
- **Reporting expectations increasing and to be tied to company value:** That said, this narrative is quickly changing – as scope 3 emissions represent an outsized share of an oil & gas company's total value chain GHG footprint. As such, positively influencing emissions outside of its own direct control can thus have significant decarbonization impacts – and stakeholders ranging from NGOs to investors are increasingly expecting companies to report on scope 3 emissions, and to formulate strategies on how to reduce them. Investors are a notable scope 3 reporting adoption driver, as they increasingly want to understand the value chain carbon footprint of a company to understand where the transition risk lies – for oil & gas the bulk of this risk resides in the use of sold products (category 11). Ensuring the long-term value of Norwegian oil and gas companies will thus be likely to depend on sufficiently ambitious scope 3 emission reduction targets and the credibility of strategies.
- **Corporate footprints are international:** Most of the scope 3 emissions footprint will be international, and strategies to reduce them may thus focus on reducing emissions occurring outside of Norway. While this will not reduce Norwegian national emissions, it can ensure continued competitiveness of oil and gas, most of which is exported and consumed abroad – and create opportunities for a Norwegian value chain, i.e. for CCS.
- **Domestic scope 3 synergies can be stimulated:** Oil and gas companies operating on the NCS will also have scope 3 emissions within Norwegian boundaries and reducing these will have a direct impact on total Norwegian emissions. This can take the form of closer collaboration with Norwegian services suppliers.

National scope 3 emissions – Delivering on national carbon budgets

- **National carbon budgets key:** At the national level, delivering GHG reductions in line with national carbon budgets is the key guiding principle for policymakers, as they have national targets and targets under nationally determined contributions (NDCs) under the Paris agreement.
- **Domestic and international emissions:** All scope 3 emissions for a Norwegian oil and gas company occurring within Norwegian national boundaries for all 15 categories go directly into a national carbon budget. This is most relevant for upstream transportation and distribution (category 4), as well as purchased goods and services (category 1) – as these will often also occur within Norwegian national boundaries. Use of sold products (category 11) and downstream transportation and distribution (category 9) are more likely to occur outside of national boundaries and thus not negatively or positively impact the Norwegian carbon budget.
- **Domestic emissions likely to take precedence:** Based on this rationale, from a Norwegian government perspective, facilitating scope 3 emissions from the oil and gas sector that occur upstream and downstream and *within* Norwegian national boundaries is likely take precedence when selecting technologies and approaches to decarbonize the NCS.
- **International emissions to come on the agenda:** A key facet of this discussion is that nation states to date has shown little appetite to take greater responsibility for scope 3 emissions from activities and products occurring outside of national boundaries. In Norway's case, national scope 3 emissions associated with the use of exported fossil feedstock and fuels are substantial. As pressures ramp up for corporates to take more value chain emissions responsibility, Norway will be pushed to take action to ensure the long-term value of its oil and gas exports.

Scope 3 opportunities – Use of sold products
Blue hydrogen production and hydrogen derivatives

Description

- **Natural Gas methane reforming with CCS:** A large share of conventional grey hydrogen is produced with natural gas methane reforming. A by-product of the process is carbon emissions, which in the case of blue hydrogen would be captured at the point of production and stored. The hydrogen would be sold as either hydrogen feedstock, or converted further into for example blue ammonia.
- **Scope 3 emission reductions:** By capturing and storing (most) of the emissions associated with methane reforming, the upstream emissions associated with the downstream use of sold products would be substantially reduced – in turn reducing value chain emissions. For hydrogen-consuming companies reporting their upstream scope 3 footprints, blue hydrogen would thus be favourable to grey hydrogen and could fetch a premium. For a blue hydrogen producer, the downstream scope 3 footprint would be reduced, reducing climate transition risk and bolstering sustainability credentials.
- **Higher emissions than exporting gas:** As it will not be cost-competitive to capture close to all of the carbon emissions from methane reforming, Norwegian emissions would be higher than if the gas is simply exported to international markets.

REPower EU Impact on blue hydrogen opportunities

- **Higher gas prices:** Rising gas prices, exacerbated by the Russian invasion of Ukraine, could shift the narrative that blue hydrogen is a transition fuel on the way to green hydrogen and derivatives.
- **Energy security considerations:** Converting natural gas to hydrogen entails high energy conversion losses, and with energy security being the core focus of REPower EU, using the natural gas for heating/cooking, power generation and industry is likely to be a more favourable option. As Europe is in direct need of gas to replace the phase-out of Russian gas, it is unlikely that significant amounts of surplus natural gas will be available for producing blue hydrogen. The need for new pipelines to transmit greater volumes of hydrogen is also a challenge, with hydrogen having about 30% of the energy content of methane. This implies that more pipeline capacity is required to transmit the same energy content, while such dedicated pipelines will take years to materialize.
- **Impact of weaning off Russian Gas:** Norway will have an outsized role in European gas, as such, it may be better to let the downstream market decide how to best utilise the gas. This would, however, give Norway little impact on scope 3 emissions from use of sold products.
- **Rising need for European ammonia:** Ammonia is typically produced with grey hydrogen from methane reforming, applying CCS to reduce emissions is likely to be expected over time.

Norwegian competitiveness perspectives

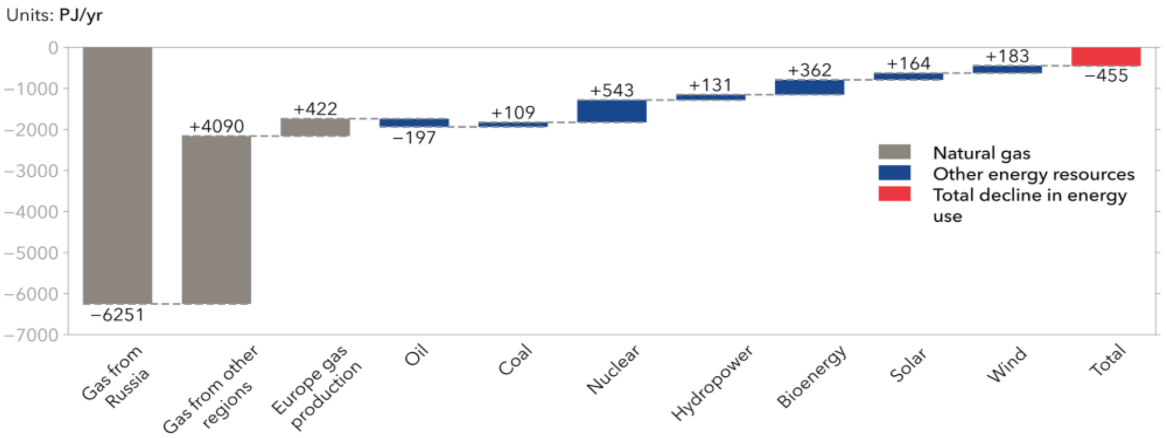
Pros:

- Blue hydrogen sold downstream leads to no use of sold products emissions
- Investing in blue hydrogen capacity better positions Norway for capitalising on the hydrogen economy.
- Rising demand for European ammonia, which today is almost exclusively grey. Applying CCS to existing grey ammonia production will be key to reducing fertiliser manufacturing GHG emissions.

Cons:

- High gas prices reduces cost competitiveness and highlights a tight gas market
- Unlikely that there will to any surpluses of Norwegian gas in line with the anticipated reduction in Russian gas. The chart below illustrates a DNV scenario for how other sources of natural gas or alternative energy replace Russian gas – of which relatively expensive LNG is essential to topping up Norwegian gas. Piped gas is more cost-competitive, highlighting a long-term market for Norwegian gas.
- High gas-to-hydrogen energy conversion cost are misaligned with EU energy security imperatives
- New pipelines that can take large volumes of hydrogen would be needed. Lower energy content of hydrogen requires more pipeline capacity for same energy content shipped
- CCS scaling benefits can be more cost-competitively derived from sectors covered by the EU ETS, with grey ammonia currently receiving free allowances due to carbon leakage risk.

Impact of Ukraine war on European primary energy mix in 2024, compared to pre-war ETO* model run



*ETO = DNV Energy Transition Outlook, Source: DNV

Scope 3 opportunities – Use of sold products
Natural gas power with (or without) CCS

Description

- **Natural gas-fired power with CCS:** Norwegian gas exported to the European continent can be used in industry, and notably in power generation. With the application of carbon capture and storage technology, up to 90-95% of carbon emissions can be captured and stored in order to reduce the carbon intensity of power generated.
- **Scope 3 emission reduction:** Unlike blue hydrogen, natural gas power with CCS will entail some downstream use of sold products emissions – as CCS technology will not capture all emissions. A seller of natural gas will also be dependent on whether the end-consumer of the gas applies CCS technology, although this could be addressed through bilateral agreements.
- **Lower emissions in Norway than with blue hydrogen:** By not taking on the gas-to-hydrogen conversion emissions in Norway, the upstream carbon emission footprint of natural gas exported to Europe will be lower than that of blue hydrogen exported to Europe.
- **Reputational risk:** However, over time, exporting gas – especially gas for end-use without CCS – is likely to strengthen a negative narrative of Norway exporting its emissions. This narrative could increase in propensity as corporate scope 3 emissions come more strongly onto the global climate change agenda and the discussions around the current energy crisis become more normalised.

REPower EU Impact on natural gas with CCS opportunities

- **Ultimate aim to reduce Russian gas reliance:** This will take place through efforts to reduce gas consumption and sourcing gas from other international suppliers. As the only market in Europe with significant gas production, Norway is likely to play a predominant role in helping to plug the gap from Russian gas.
- **Maximizing the effect of natural gas is another key aim:** Another energy security imperative will be to ensure that the natural gas consumed has the greatest impact. As such, utilising natural gas to generate power and heat is likely to take precedence over converting it to hydrogen.

Perspectives on Norwegian competitiveness

Pros:

- Norwegian natural gas export is key to plugging Russian supply gaps and bolstering European energy security. More expensive LNG imports will also be phased-out before Norwegian gas, highlighting long-term demand also in the face of long-term gas demand reductions in the EU.
- Likely limited European appetite for converting gas to hydrogen due to energy conversion loss, ensuring long-term attractiveness of Norwegian natural gas.
- Natural gas power has a sizeable role in the EU Taxonomy, and will likely help to reduce downstream use of sold product emissions for Norwegian exported gas over time. The 100g CO_2e/kWh lifecycle emission Taxonomy threshold further highlights the importance of minimising gas production and transport emissions, putting piped Norwegian gas at an advantage relative to i.e., liquified natural gas.
- Exporting natural gas over blue hydrogen leads to lower emissions in Norway, due to CCS not capturing all emissions.
- A pipeline of CCS projects can establish Norwegian technological expertise that can be exported. This could in turn enable Norway to capitalise on international opportunities, as well as to showcase a greater commitment to taking responsibility for downstream emissions.

Cons:

- Over time, use of sold products emissions downstream can create reputational risk and put spotlight on Norway exporting emissions.
- An overarching focus on maximizing gas exports could reduce sense of urgency in quickly establishing a robust hydrogen economy in Norway.

Downstream natural gas w/CCS with the CO2 shipped to Norway – a potential opportunity?

- **CCS as a Norwegian service for continental Europe:** According to the NPD's CO_2 atlas, it is possible to store up to 80bn tonnes of CO_2 on the NCS. There could be long-term scope for shipping such emissions for storage in Norway.
- **COP26 Article 6 and related opportunities:** The finalization of article 6 on carbon trading, and notably 6.2 on bilateral actions could create new opportunities Norwegian carbon storage. Notably, Norway could in theory be able to deduct emissions captured internationally but stored in Norway from the Norwegian carbon budget – if in ownership of the carbon stored, enabled by the contract structure. However, the details on this remain uncertain, notably on the liability of storage leaks. It could also be argued that Norway would be importing more emissions in this case, and a more likely outcome is thus that Norway stores CO_2 on behalf of other markets.

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