TOWARDS NEAR-ZERO

Evaluating direct emission reduction pathways for Norway's oil and gas industry in line with 2050 targets

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1 EXECUTIVE SUMMARY: KEY FINDINGS

The Norwegian oil and gas industry has initiated efforts to decarbonize their operations on the Norwegian continental shelf, with an ambitious goal of achieving near-zero direct (scope 1) emissions by 2050. This study examines how the industry could reach their climate targets, while addressing the associated challenges and complexities of doing so. Using the Norwegian Offshore Directorate's (NOD) high production scenario as a baseline, we have assessed the key technologies required and how to scale them to achieve emissions reductions targets. Even with aggressive technology deployment some emissions will remain, and this study also considers potential measures to address them. Our findings are consolidated into a roadmap that charts a potential pathway toward decarbonizing the Norwegian continental shelf by 2050 while highlighting the key challenges.

Navigating the decarbonization challenge

Oil and gas production on the Norwegian Continental Shelf (NCS) generate significant scope 1 emissions, with gas turbines powering the operations responsible for over 80% of these emissions. The industry has set a near-term target of 50% reduction by 2030 compared to 2005 levels, and a 90-95% reduction by 2050 (which we refer to as "near-zero" in this report). However, achieving these targets is complex: despite decarbonisation technologies being largely available, there are still many challenges to be solved. These challenges become more complex under NOD's high production scenario, which includes rapid field developments in more remote regions like the Barents Sea.

Given this starting point, our study examines the primary question: *What would it take for the Norwegian oil and gas industry to reach near-zero emissions by 2050 while maintaining high production?* The answer, as our roadmap reveals, lies in a coordinated approach that prioritises cost-effective electrification, builds new power generation capacity, develops zero-emission drilling solutions, and incorporates carbon removal technologies to offset the residual emissions.

Although a range of technologies could contribute to emission reductions with no one size fits all, we focused on the approaches above due to their maturity, feasibility, and high potential impact. Nevertheless, the relevance of smaller and emerging technologies remains important and will likely be essential in bridging the final gaps to achieve the near-zero target.

Electrification as the cornerstone of decarbonisation

Electrification emerges as the most effective way to reduce reliance on gas turbines and significantly cut emissions. **Power-from-shore is generally the most cost-effective solution**, particularly for new installations or those near the onshore grid. However, **it is dependent on significant development of both new power generation and transmission capacities at competitive costs.** Driven not only by the power demands of the petroleum sector but also by the broader electrification of Norwegian industry and society, the power required under NOD's high production scenario adds to the challenge. Offshore wind and gas-fired power hubs with carbon capture and storage (CCS) offer alternative or supplementary options – either for remote locations where grid connections are less feasible or combined with grid connection to support the build-out of new power capacity.

Our case study results (see Figure 1-1) reveal that **power-from-shore offers the highest net present value (NPV) improvement to business as usual**, driven by reduced CO_2 taxes and fuel savings. Immediate implementation yields the most benefit, with a potential NPV increase of 23% (5,800 MNOK in savings) when pursued today. Delaying until 2040, however, reduces the advantage to a 4% improvement. Offshore wind also achieves cost savings, although high initial capital expenditure (CAPEX) limits the NPV benefit. Gas-fired power hubs with CCS, while technically feasible, remain economically challenging due to high CAPEX and operating costs. However, our analysis is high level and contains several assumptions that are still uncertain. The preferred solution for each case will ultimately depend on specific project characteristics. For a more detailed description of the case study and sensitivities, see Chapter 6.

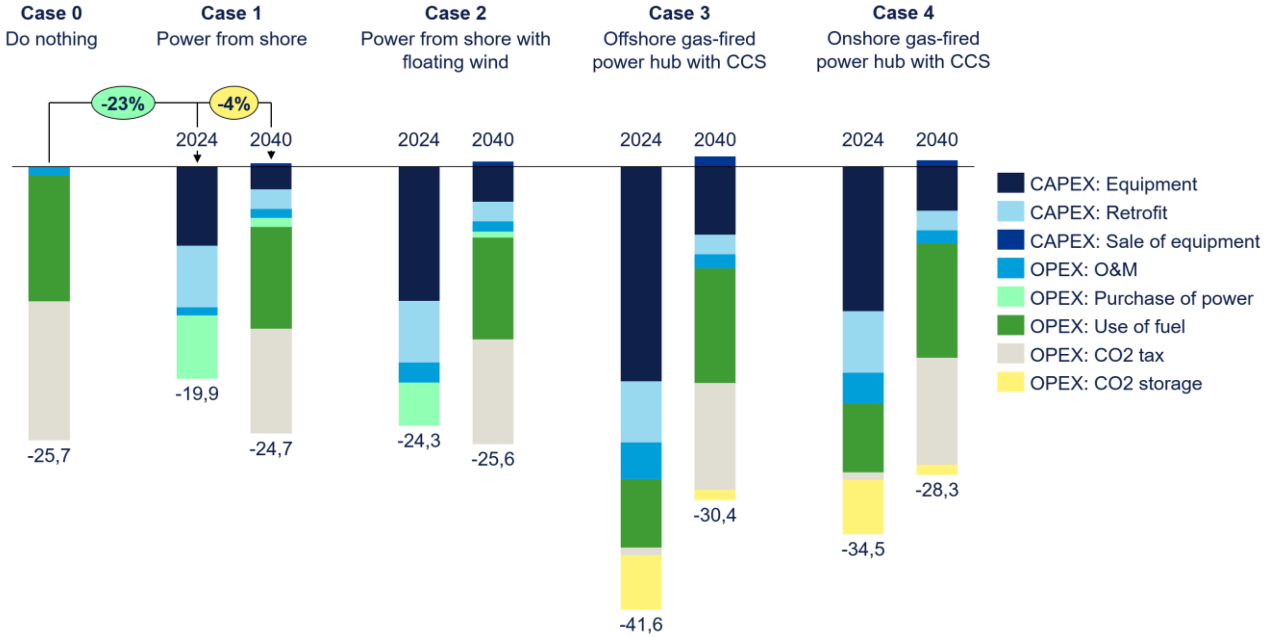

Figure 1-1: NPV results [in 1000 MNOK] from the case study, comparing full electrification in the near term (construction start 2024) with the long term (construction start 2040) against the baseline of doing nothing.

Electrification is most cost-effective for new installations, where assets can be designed to optimise electrification from the outset. For existing assets, retrofitting is more complex and costly due to space limitations and the associated loss in revenue due to construction downtime. Partial electrification could offer a viable compromise, but this depends on the level of production expected from older installations through 2050. If substantial production is tied to these assets, full electrification may ultimately be necessary.

Addressing residual emissions: the potential role of carbon removals

Despite a robust electrification strategy, certain emissions – such as those from flaring and hard-to-abate operational sources – will remain. To offset these residual emissions, carbon removal solutions will be needed, such as Direct Air Capture with Storage (DACCS), Bioenergy with Carbon Capture and Storage (BECCS), and the novel Direct Ocean Carbon Capture and Storage (DOCCS).

Currently, however, regulatory frameworks like the EU ETS only permit emissions reductions from direct facility operations, meaning carbon removal units would need to be installed within the operational boundaries to count toward compliance. To make external carbon removal credits feasible, the ETS would need to recognise these credits in future regulatory adjustments – a topic currently under discussion. If carbon removal credits are implemented as part of the ETS, a robust certification framework – such as the anticipated Carbon Removal Certification Framework (CRCF) – will be necessary to ensure that these removals are measurable, verifiable, and offer long-term storage.

In summary, for carbon removal credits to be a viable tool for offsetting industry emissions, the following factors will be essential:

- **Regulatory adaptation:** Policy shifts within frameworks like the EU ETS will be necessary to recognise carbon removal credits, ensuring they can complement direct emission reductions. The anticipated certification framework for carbon removals will play an important role by establishing standards to verify their credibility.
- **Focus on long-term CO_2 storage and additionality:** Best practices for carbon removal emphasise technologies with long-term CO_2 storage, ensuring durability. Credits should meet standards of additionality, proving they would not be viable without carbon credit revenue and that they contribute beyond Norway’s national targets.
- **Targeted financial incentives:** Effective incentives – such as tax benefits, auction schemes, or investment support – can reduce barriers to entry, making it feasible for companies to integrate carbon removal projects into their decarbonisation strategies.

Roadmap results: a potential pathway to near-zero in 2050

Our roadmap (see Figure 1-2) presents a potential pathway to near-zero emissions by 2050, showcasing the estimated range of emissions reduction potential within each decarbonization measure. This range underscores the need for a high level of commitment and collaboration across the industry. If the maximum decarbonisation potential is realised, the sector could achieve a 93% reduction in emissions compared to 2005 levels, meeting the 2050 target. However, realising this goal will require an accelerated adoption of key technologies, targeted R&D investments, and coordinated efforts across all disciplines. For emissions that remain beyond the reach of current technological solutions, high-quality carbon removal credits will be needed. To unlock their potential, advancements in regulatory frameworks are needed, with discussions currently ongoing in the EU.

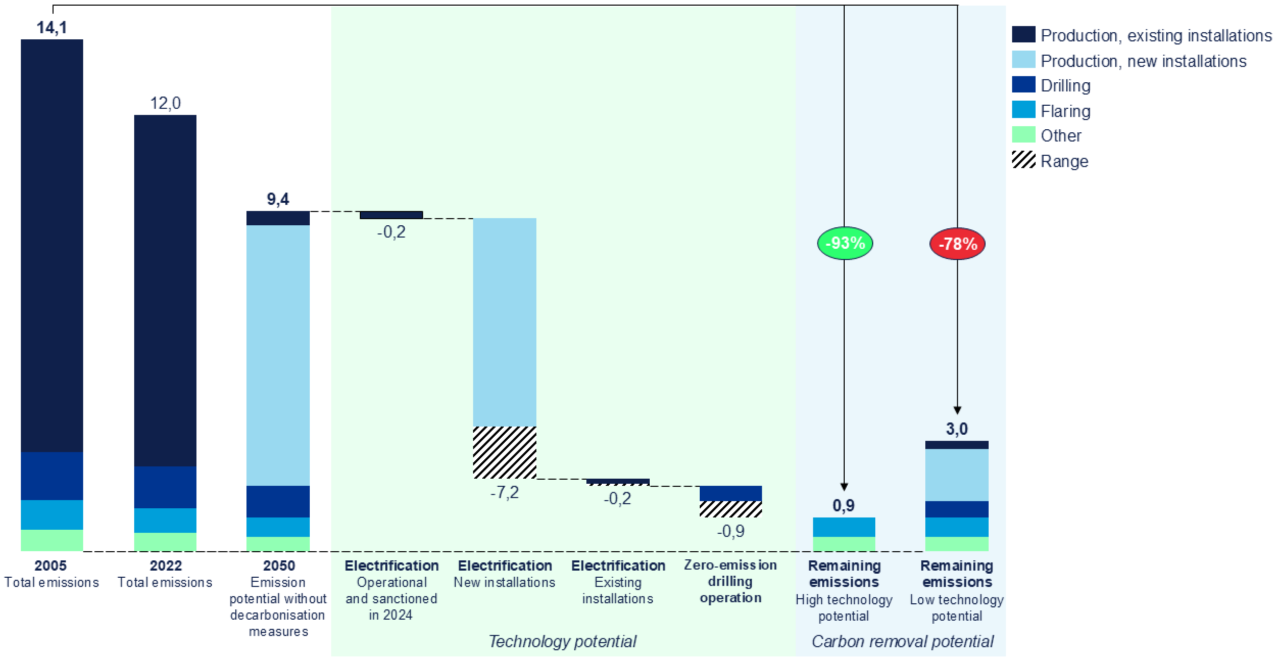

Figure 1-2: Roadmap to emission reductions in 2050 under NOD's high scenario [million tonnes CO_2e]

Within the technology potential, our roadmap provides a merit order on electrification measures, prioritising the simplest and most cost-effective solutions. The emission reduction potential of different electrification measures – including power-from-shore, offshore wind, and gas-fired power with CCS – has been bundled together, as these solutions offer comparable means of emission reduction, albeit with unique strengths and challenges. The preferred solution for each case will ultimately depend on specific project characteristics. Zero-emission drilling – through use of low-carbon fuels or electrification – will also be essential for reaching near-zero emissions. For more details on each technology pathway, please refer to Chapter 5.

Our findings highlight that the vast majority of emission reduction potential lies in electrifying new installations, which can prioritise electrification from the outset. For brownfield assets, full electrification of non-electrified assets remains challenging, costly, and may not be economically viable if retrofitting expenses are high. Partial electrification could offer a viable compromise, given the limited remaining production expected from these assets in 2050. The full roadmap, including important assumptions and limitations, can be found in Chapter 8.

Pathway to near-zero: key success factors

Realising the roadmap requires industry-wide commitment to several key factors:

- **Coordinated electrification strategies** to establishing shared infrastructure, such as power hubs serving multiple fields, can enhance scalability, improve resource utilisation, and generate significant cost savings. A grid-integrated offshore power system offers long-term benefits by ensuring a secure power supply and supporting the broader energy system as oil and gas production declines, thereby also reducing investor risk.
- **Focusing R&D on adaptable technologies with applications beyond the petroleum sector** can accelerate technology development and leverage economies of scale. Examples include high-voltage direct current (HVDC) technology, subsea grid systems, and carbon capture and storage (CCS) – all essential technologies that can benefit from scaling across other industries, which will enable technological maturity and cost

reduction through broader applications. Cross-industry collaboration in R&D will be essential to unlock this opportunity.

- **Predictable, long-term policy frameworks** are key in enabling high-stakes investments in decarbonisation initiatives. A clear policy direction will help mitigate project delays, especially in projects like power-from-shore where competition for grid capacity is a persistent issue. The need for a holistic energy plan with clear and predictable policy frameworks has also been highlighted in OG21's 2023 Annual Report.
- **Investing in large-scale build-out of new power generation** at competitive prices is essential to move the decarbonisation of Norwegian industry and society forward, including the petroleum sector. Integrating power-from-shore and low-emission power production opens up valuable opportunities for the oil and gas industry to contribute to building out regional power capacity while advancing sector-wide decarbonisation. Co-locating power generation with consumption can also help balance regional supply and demand while minimising the need for costly grid expansions.

In addition to these overarching success factors, targeted R&D and other measures will be required to support cost reduction, scalability, and efficiency improvements across each technology. For a detailed list of R&D focus areas, please refer to Chapter 5.

Power-from-shore

Key challenges: Limited onshore grid capacity necessitates large-scale build-out of new power generation to meet the growing demand, especially for offshore electrification. Long-distance connections require high-voltage direct current (HVDC) systems, which face challenges related to space constraints, global supply limitations on cables and converters, and lower maturity for ship-based FPSO electrification.

R&D focus areas: Develop modular, standardized HVDC equipment to improve supply chain resilience and cost-effectiveness. Innovate in subsea or compact equipment to reduce topside footprint. Further advance dynamic DC cables and DC turrets for ship-based FPSOs to enhance flexibility, as well as long-distance HVAC.

Offshore wind

Key challenges: Intermittent power generation means backup is required to ensure continuous supply. The specific emission reduction potential varies by configuration, and zero-emission backup solutions are less developed than conventional gas turbines. For deep waters on the NCS, floating wind is predominantly needed, though it currently faces higher costs and lower maturity than bottom-fixed options.

R&D focus areas: Standardize designs for floating turbines, floating platforms and mooring systems, and strengthen supply chains to reduce costs. Develop dynamic DC cables for shore connections. For off-grid solutions, focus on developing zero-emission back-up systems, such as large-scale batteries and hydrogen storage.

Gas-fired power with CCS

Key challenges: Emission reductions rely on high capture rates, yet current amine-based capture systems often perform below the anticipated 90% efficiency. Offshore units are at early development stages, facing lower maturity compared to onshore systems. CO_2 transport and storage infrastructure remains limited, and challenges such as flow assurance, corrosion, and high capture system costs persist.

R&D focus areas: Innovate in capture technology, especially promising novel capture methods, to improve efficiency, real-world capture rates, and reliability while bringing down costs. Further innovate on equipment design, such as modular and compact solutions for cost reductions and standardisation. Increase collaboration, learning, and knowledge sharing to avoid cost overruns and project delays. Further develop transport and storage solutions to reduce costs and increase availability of supportive CCS infrastructure.

Zero-emission drilling

Key challenges: Retrofitting is more feasible than new builds due to extended construction times and financing constraints. Full electrification is limited by the need for long power cables, and biofuel supply faces challenges related to supply. Other low-carbon fuel alternatives present challenges such as toxicity, storage limitations, low maturity, and high costs.

R&D focus: Retrofit kits for alternative fuels are key to transforming the existing fleet. Focus on improving rig efficiency to enable dual-fuel operations, and further pilot and test rig operations using alternative fuels. Increase availability of affordable, low-carbon fuel supply. Additionally, a coordinated push from government through available funding, and pull from operators through long-term contracts at favourable day rates, will be essential to justify investment in zero-emission upgrades.

Conclusion: Paving the way to near-zero in 2050

This study outlines a potential pathway for the Norwegian oil and gas industry to reach near-zero emissions by 2050. Rather than showing a fixed future, it aims to inspire actionable dialogue on where to prioritise decarbonisation efforts, identifying key success factors and addressing the R&D focus areas necessary to meet the industry’s ambitions.

However, it is important to note that our results are subject to several uncertainties. Key assumptions were made on future production, technology costs, and emission reduction potential, and important data has been unavailable due to confidentiality restrictions. For more details, please refer to Chapter 4. Combined, this introduces variability in the outcomes and the feasibility of achieving the 2050 targets. As such, while the roadmap presents a potential pathway, actual outcomes will depend on continuous and innovation and development of technology, adaptive policies, and strong collaboration.

2 INTRODUCTION

Fossil fuels have long been the cornerstone of the global energy supply, accounting for 80% of our primary energy needs. While their dominance has persisted for decades, we are now seeing a dramatic shift with the uptake of renewable energy sources. DNV forecasts that, within the next few years, the fossil share will decrease by one percentage point annually, accounting for less than half (48%) of the primary energy mix in 2050[1]. This transition is the single most effective way in reaching our climate objectives, considering most of the oil and gas emissions stem from the consumption of these products (known as indirect or scope 3 emissions). For the operators at the NCS, scope 3 emissions account for 94-98% of the total emissions from their products, as reported by KonKraft[2].

However, with almost half of the world's primary energy being supplied by fossil fuels in 2050, emissions associated with all aspects of the value chain matter. This also includes the operation of oil and gas assets. Although direct (scope 1) emissions account for a small share (1-5%) of the total emissions from the Norwegian continental shelf[3], they account for the largest share of Norway's emissions (around 25%)[4]. Without cutting these emissions, the nation's climate targets for 2030 and 2050 will be out of reach. As such, the commitment of Norwegian's petroleum industry to reduce scope 1 emissions with 50% by 2030 and near-zero by 2050 – as outlined by KonKraft – is of great importance. Moreover, transitioning its technological competence and engineering knowledge will provide a de-risked long-term business model in a low-carbon future. This transition will thus not only align with the global transition in reducing emissions but also pave a way for Norway's future industries.

As part of their mission to promote technology developments that can help achieve the 2030 and 2050 climate objectives, OG21[5] has asked DNV to explore how Norway can achieve near-zero direct emissions from the NCS by 2050 through the implementation of technology and new business models, while O&G production follows the Norwegian Offshore Directorate's high production scenario (defined in Chapter 2.2). The key objectives of this study include:

- **Assessment of technologies:** Identify and evaluate existing and emerging technologies that can significantly reduce scope 1 emissions in the petroleum sector in line with 2050 targets.
- **Business model evaluation:** Explore alternative business models[6] that could potentially support emission reduction efforts.
- **Research and development (R&D) efforts:** Investigate ongoing R&D initiatives and identify gaps requiring additional focus to accelerate technology implementation.
- **Roadmap towards 2050:** Develop a decarbonisation roadmap outlining a possible pathway to reaching near-zero emissions in 2050.

With this study, we aim to identify those technologies and business solutions that will most effectively move the industry towards near-zero emissions in 2050 and chart a course for their advancement.

2.1 Our approach to the work

The work has been structured into distinct but interlinked phases designed to systematically address the project objectives. Throughout the study, collaboration and stakeholder engagement have been key, with workshops and discussions involving the OG21 project team and its Technology Groups (TGs), as well as external stakeholders to

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1 DNV (2023): Energy Transition Outlook

2 KonKraft (2023): The Energy Industry of the Future on the Norwegian Shelf – Climate Strategy towards 2030 and 2050 – Status Report 2023

3 KonKraft (2023): The Energy Industry of the Future on the Norwegian Shelf – Climate Strategy towards 2030 and 2050 – Status Report 2023

4 https://miljostatus.miljodirektoratet.no/tema/klima/norske-utslipp-av-klimagasser/

5 OG21 is one of four national strategies on the research, innovation, commercialization and industrialization of important industries in Norway. It has its mandate from the Norwegian Ministry of Energy, with the secretariat for OG21 siting under the Norwegian Research Council.

6 In this context, we refer to using carbon credits to offset hard-to-abate emissions.

validate findings and leverage collective knowledge. A special thanks is extended to all contributors for their invaluable input.

The findings from our work are structured into the following chapters in the report:

- **Chapter 3** focuses on framing the energy transition landscape, highlighting key global trends on oil and gas demand as well as climate policy impacts, and the implications in a Norwegian context. Here, we also dive into the status of Norwegian climate targets and scope 1 emissions from the petroleum industry.
- **Chapter 4** dives into the assumptions behind NOD's high production scenario and develops an emission baseline in 2050 used throughout our analysis.
- **Chapter 5** presents a detailed analysis of selected technologies with a high potential for scope 1 emission reductions in line with the 2050 targets, including ongoing R&D efforts and recommendations for future research. The selection was done based on a comprehensive mapping, screening, and prioritisation methodology, described in more detail in the Appendix.
- **Chapter 6** is tied to the analysis done in the previous chapter, presenting a case study on various electrification measures using a NPV assessment, including a sensitivity analysis on key parameters.
- **Chapter 7** explores the potential within alternative business models to reduce scope 1 emissions from the industry, focusing on carbon offset mechanisms.
- Lastly, **Chapter 8** synthesizes our key findings into a roadmap for 2050, outlining the potential within each emission reduction measure to answer the key question: What will it take for the industry to meet its 2050 climate targets under NOD's high production scenario?

2.2 Key terms and abbreviations

The following key terms have been defined at the start of the study:

- Near-zero: A 90-95% reduction in scope 1 greenhouse gas (GHG) emissions, in line with Norway's climate targets to become a low-emission society.
- NOD's high production scenario: As described by the NOD's "High resource growth with considerable and fast technology development"[7], in line with OG21's request.
- Direct emissions: Classified as scope 1 emissions from the production of Norwegian oil and gas, including land-based facilities.

A list of abbreviations can be found in Appendix A.

[7] https://www.sodir.no/aktuelt/publikasjoner/rapporter/ressursrapporter/ressursrapport-2022/6-framtidig-produksjon-og-inntekter/

3 FRAMING THE ENERGY LANDSCAPE: GLOBAL TRENDS AND NATIONAL IMPLICATIONS

This chapter examines the global and Norwegian energy landscapes with a focus on the oil and gas sector. It discusses the implications of the energy transition, the role of oil and gas in ensuring energy security and supporting critical industries, the projected use of oil and gas towards 2050, and Norway's climate goals and energy plans.

3.1 A global outlook

3.1.1 Transitioning away from fossil fuels – but not fast enough

The energy transition is being driven by a combination of factors: the rapid adoption of renewable energy, advancements in technology that lower costs, and supportive policy measures aimed at reducing reliance on fossil fuels. Notably, The Intergovernmental Panel on Climate Change's (IPCC's) Sixth Assessment Report highlights the urgent need for a substantial reduction in fossil fuel use, emphasizing that to limit global warming to 1.5°C, emissions must be reduced by at least 43% by 2030 and 60% by 2035 compared to 2019 levels. This requires a rapid transition to renewable energy sources and significant improvements in energy efficiency[8].

DNV's Energy Transition Outlook (ETO) 2024[9] - which forecasts our most likely future for the energy transition – shows that the transition is at the starting blocks, with global energy-related emissions likely peaking this year (2024). It is at this peak that the transition begins, although the energy-related emissions have started to fall already across many countries and regions. As an example, Europe's energy related CO_2 emissions peaked in 2007.

In the coming decades, we forecast a gradual phase-down of fossil fuels. Coal is the first fossil fuel to see a steady decline due to its high carbon footprint, followed by oil, and eventually natural gas which still maintains a high share of the primary energy supply mix towards 2050. Despite the growing competitiveness of renewables compared to fossil-fired electricity, it will take many years for low- and zero-emission energy sources to fully replace fossil fuels in the broader energy system. Nevertheless, our ETO has consistently indicated that the demand for fossil fuels will begin a steady decline before the end of this decade. The International Energy Agenda (IEA) also supports this view, stating that the world is at the “beginning of the end” of the fossil-fuel era[10].

Despite the rapid uptake of renewables, the pace of the transition is not fast enough to reach net-zero in 2050. That would require roughly halving global emissions by 2030, but our most likely future shows that this will not even be achieved in 2050: by mid-century, we forecast global energy-related CO_2 emissions will only be 46% lower than today (and only 4% lower than today in 2030), leading to a global warming of 2.2°C by the end of this century.

3.1.1.1 Climate policies are critical in reaching net-zero

Although achieving a net-zero future by 2050 is more difficult than ever, it is not impossible, and our ETO emphasizes the crucial role of policies in ensuring we reach this target. Governments worldwide are now implementing stringent regulations to curb carbon emissions and promote renewable energy adoption. The roll-out of big decarbonization policy packages in the last years, such as the US Inflation Reduction Act and the EU's Fit for 55 and REPower EU, are resulting in a rapid transition regionally which also drives forward the global transition. As an example, global investments in clean energy are set to be twice the amount going to fossil fuels this year[11].

The global stocktake at the 28th UN Climate Change Conference (COP28) marked the “beginning of the end” of the fossil fuel era, calling for accelerated actions for the phase-out of fossil fuels and installation of renewable energy

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[8] https://climatechampions.unfccc.int/the-ipcc-just-published-its-summary-of-5-years-of-reports-heres-what-you-need-to-know/
[9] DNV (2024): Energy Transition Outlook
[10] https://www.iea.org/reports/world-energy-outlook-2023/executive-summary
[11] https://www.iea.org/news/investment-in-clean-energy-this-year-is-set-to-be-twice-the-amount-going-to-fossil-fuels

capacity globally[12]. As part of the conference, 50 oil and gas majors, responsible for 40% of global production, also signed a pledge to commit to net-zero operations by 2050 and near-zero methane emissions by 2030.

Despite these movements, criticism remains regarding the petroleum industry's pace and scope of transition efforts. Notably, the signed pledge focuses only on operational emissions (scope 1 and 2), and not the emissions resulting from the end use of their products (scope 3) which are the main contributors to the overall emissions from the industry[13]. It is, however, important to acknowledge that, although the industry holds significant responsibility, addressing emissions from oil and gas also requires action beyond the industry itself. As long as demand for these products remains high, the transition will be slower. The challenge therefore lies in either reducing demand ('demand destruction') and (or) regulating supply through government policies. Effective policies that curb demand and promote alternatives are essential for a faster shift toward net-zero.

3.1.1.2 Energy security is moving to the top of the agenda

The energy trilemma describes the attempt to balance energy security, affordability, and sustainability. Although the focus in the last decade has been to ensure sustainable energy supply, energy security is now moving to the top of the agenda due to the shifting geopolitical landscape and a price shock on energy imports. Locally produced energy is being prioritised over imports worldwide, and we see a gradual move towards less international trade and more focus on national energy security, supply chains and local manufacturing. In the longer term, we forecast a shift from a world where energy is extracted in a handful of nations and traded over long distances to the rest of the world, to a situation where energy is produced locally, largely by renewables, and consumed locally in the form of electricity. Notably, our ETO forecasts that electrification will more than double over the next 30 years, a trend that has intensified owing to these energy security concerns. 'Energy security' is now becoming a driver of change in the coming energy future.

Energy security concerns differ and diverge across regions. Energy importing regions will favour resources that are locally available or accessible from reliable partners; exporting countries will have to convince their partners that they are a trustworthy, long-term source of supply. Although this has led to an increase in e.g. coal demand in some regions, the long-term trend sees energy security and sustainability pulling in the same direction, with renewable energy mixes increasingly shielding national energy systems from the volatility of the international energy trade. We will look more into Norway's role in relation to energy security and as a trade partner with the EU in Chapter 3.2.4.

3.1.2 Energy demand is changing

In 2022, electricity accounted for 19% of the world's final energy use. By 2050, DNV's ETO shows that this is expected to rise to 35%. This increase highlights the growing efficiency and importance of electricity, suggesting that by mid-century, over half of all energy services will be provided by electricity, while the direct use of fossil fuels will decrease – from 67% of final energy demand today to 47% by 2050

Several factors drive this shift: advancements in electrification technologies, cost reductions in solar and wind power, and supportive policies. The superior efficiency of electricity, combined with its relatively easier decarbonization, makes it a preferred energy carrier. DNV therefore sees policies steering towards decarbonisation through electrification where possible, followed by other energy carriers like ammonia, hydrogen and e-fuels where needed.

[12] https://unfccc.int/news/cop28-agreement-signals-beginning-of-the-end-of-the-fossil-fuel-era
[13] https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/120223-cop28-fifty-oil-and-gas-companies-sign-net-zero-methane-pledges

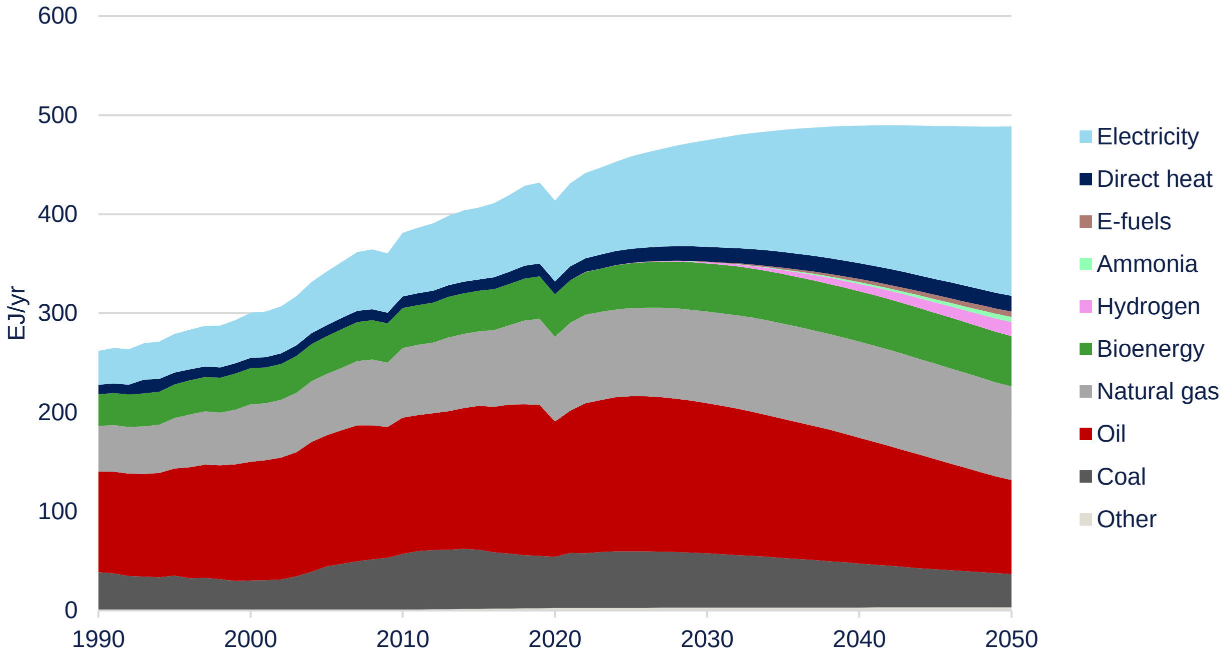

Figure 3-1: Final energy demand by carrier[14]

It is important to highlight that the above results show what DNV believes to be the most likely future, resulting in a 2.2°C warming within the end of the century. The IEA net-zero-emissions scenario (NZE) shows a slightly different picture, where demand for coal, oil and natural gas would need to drop to less than 20% of the global total by 2050 if the world is to succeed on reaching the 1.5°C target. A transition in alignment with the announced pledges scenario (APS), leading to 1.7°C warming, would require demand for coal, oil and gas to drop to around 40% of the total in 2050.

There are many scenarios that project the future demand for oil and gas. Below, we summarise some of the key drivers behind the change in global demand, based on the results from our own ETO report. While substitution is expected in some sectors, such as the shift towards electric vehicles and renewable energy sources, residual demand for oil and gas will remain. It is important to note that other scenarios will give other results, and a future aligned with the 1.5°C target will require even further reduction in the demand for oil and gas towards 2050.

3.1.2.1 Demand for oil will nearly half

By 2050, demand is anticipated to fall to 52 Mb/d, a 40% drop from 2025 levels[15]. The most significant decline will occur between 2035 and 2050, driven by accelerated electrification in road transport, which is the primary consumer of oil, and will remain so towards 2050.

The petrochemical sector, which uses oil as feedstock for non-energy purposes like plastics production and chemicals, is the second-largest demand sector for oil. Despite advances in recycling and alternative materials, reducing demand in this sector is challenging. In absolute terms, non-energy oil demand will increase from 22 EJ per year (10 Mb/d) today to 26 EJ per year (11.5 Mb/d) by 2035, before gradually decreasing to 22 EJ per year (10 Mb/d) by 2050 due to reductions in plastics production and higher recycling rates.

[14] DNV (2023): Energy Transition Outlook
[15] DNV (2023): Energy Transition Outlook

Manufacturing, the third-largest sector for oil use, will maintain a demand of around 11 EJ for the next decade before declining to 9 EJ. Its share of total oil demand will rise from 7% to 9% by 2050 as demand in other sectors diminishes.

3.1.2.2 Demand for natural gas will decline, but not as rapidly

The transition from coal to natural gas is driven by its lower carbon intensity and higher efficiency, supported by extensive pipeline networks and liquefied natural gas (LNG) infrastructure. In 2022, natural gas demand reached 166 EJ (4,795 billion cubic meters [bcm]), dominated by power generation demand. The primary factors driving changes in natural gas demand towards 2050 are the expansion of renewable energy and electrification, and the increasing role of natural gas in new sectors such as hydrogen production. Our analysis show global demand is expected to peak at 5,000 bcm by 2027, before gradually declining to around 4,200 bcm by 2050[16].

Power generation: The power generation sector is rapidly moving away from natural gas towards renewables. The share of natural gas in power generation is expected to decrease as solar, wind, and other renewable sources become more prevalent. By 2050, natural gas will account for 25% of the energy demand for power generation (37 EJ), down from 35% today (62 EJ).

Buildings: Towards 2050, we expect electricity to take an increasingly larger share in the energy demand for buildings due to energy efficiency improvements, such as the adoption of electric heat pumps. Although this contributes to a reduction in the share of natural gas demand, the amount in absolute terms will remain relatively stable at 37 EJ due to an overall increase in energy demand for this sector.

Manufacturing: Certain manufacturing processes require high-temperature heat, which is currently supplied by natural gas. Transitioning to alternative energy sources is slower due to technical and economic barriers, and the demand for natural gas is expected to increase from today's 27 EJ (16% of total energy demand) to 32 EJ by 2050 (21% of total energy demand).

Own use: Own use of natural gas in the energy sector will grow over the next five years but return to current levels by 2050 due to efficiency gains, electrification of production facilities, and reduced flaring. Some of this use will be for liquefaction and regasification of LNG.

Regional demand will vary. While Sub-Saharan Africa and India Subcontinent will see major growth as they transition from coal, Europe and OECD Pacific will see a steady decline to about 35% of 2022 levels by 2050. This is largely driven by high gas prices, energy conservation policies, and the shift towards renewable energy. We will look more into Norway's role in supplying Europe with natural gas in Chapter 3.2.4.

3.2 Zooming in on Norway

3.2.1 Norway's climate commitments

Norway has committed to emissions reductions in line with the Paris Climate Agreement. Since submitting its Nationally Determined Contribution (NDC) in 2015, Norway has updated its NDC a few times. In 2022, Norway's 2030 goal was updated to commit to a target of at least 55% reduction in greenhouse gas emissions compared to 1990 levels.[17]

Norway's climate targets for 2030 and 2050 are established by law in the Norwegian Climate Change Act.[18] The Act stipulates a 55% greenhouse emissions reduction by 2030 from 1990 levels. For 2050, the goal for Norway is to become a low emissions society, which implies greenhouse gas reductions of 90%-95% from the reference year 1990.

To fulfill its climate targets, Norway aims to cooperate with Iceland and the EU. To that end, the EU Emissions Trading System (EU ETS) is the EU's and Norway's main instrument to incentivize decarbonization and reduce emissions in line

[16] DNV (2023): Energy Transition Outlook
[17] Update of Norway's national determined contribution
[18] https://lovdata.no/dokument/NL/lov/2017-06-16-60

with the EU decarbonization targets of reducing greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels, and of becoming climate-neutral by 2050, as set out in the European Climate Law.[19] According to Norway's Climate Action Plan, about 95% of greenhouse gas emissions from the Norwegian oil and gas industry are subject to EU ETS.[20] In addition, emissions from the oil and gas sector and domestic aviation are subject to a Norwegian carbon tax. Tax rates in the non-ETS sectors vary. Whereas the tax on mineral oil is high in Norway, certain industries and uses are exempted from the CO_2 tax or taxed at a reduced rate, such as fishing in distant waters (exempted) and the greenhouse industry (reduced rate).[21]

3.2.1.1 The petroleum industry has committed to emission reductions in line with Norwegian targets

In 2020, KonKraft, a collaboration arena for Offshore Norway, the Federation of Norwegian Industries, the Norwegian Shipowners' Association, the Confederation of Norwegian Enterprise (NHO) and the Norwegian Confederation of Trade Unions (LO), with the LO unions Fellesforbundet and Industri Energi, published a Climate Strategy for the Norwegian oil and gas sector titled "The energy industry of the future on the Norwegian continental shelf – Climate strategy towards 2030 and 2050". The target was to reduce emissions of the oil and gas sector by 40% by 2030, compared to 2005 levels, and then to near zero by 2050.

After KonKraft launched its climate strategy in January 2020, the Norwegian Parliament asked the government to present a plan together with the industry to reduce greenhouse gas emissions by 50% by 2030. KonKraft thus aligned its strategy, with the goal of halving emissions by 2030.[22]

The KonKraft climate goals are largely aligned with Norway's legally binding climate goals, as set out in the Paris Climate Agreement and in the Norwegian Climate Act. While the EU ETS is an instrument which should, in the long run, ensure that the European economy achieves net zero emissions in the long run, the Norwegian government has not (yet) introduced an instrument or legally binding agreement to ensure that the oil and gas industry will achieve its 2030 emissions reduction goals. Therefore, the KonKraft climate targets can be seen as voluntary industry emission reduction targets.

3.2.2 Current emissions from the Norwegian petroleum industry

There are several sources available for Scope 1 emissions from the Norwegian oil and gas industry which are shown in Figure 3-2. These are NOD[23], Statistics Norway (SSB)[24], the Norwegian Environmental Agency[25], Miljøstatus.no[26], and Offshore Norway[27]. All these sources use the AR5 GWP100 value of 28 for methane, which we note is now out of date[28]. There are significant differences between the sources as can be seen in the chart below, and it is not clear exactly which facilities are included in each of the three different sources. The current spread between these numbers is around 500,000 tonnes of CO_2 equivalents for the latest two years of data. This is significant considering that 2050 targets for near-zero emissions are 90 – 95% below 2005 levels, given that 2005 has a spread in the data of 1,400,000

[19] https://climate.ec.europa.eu/eu-action/european-climate-law_en
[20] Meld. St. 13 (2020-2021) Report to the Storting (white paper): Norway's Climate Action Plan for 2021-2030
[21] https://energifaktanorge.no/en/et-baerekraftig-og-sikkert-energisystem/avgifter-og-kvoteplikt/
[22] KonKraft (2024): The Energy Industry of the Future on the Norwegian Shelf – Climate Strategy towards 2030 and 2050 – Status Report 2024
[23] https://www.sodir.no/aktuelt/publikasjoner/rapporter/sokkelaret/sokkelaret-2023/tall-og-fakta/ data available at https://www.norskpetroleum.no/miljo-og-teknologi/utslipp-til-luft/
[24] https://www.ssb.no/statbank/table/13931/tableViewLayout1/
[25] https://www.norskeutslipp.no/ figures compiled by DNV and include all of the category *Petroleumsvirksomhet til havs* and the following onshore facilities: Gassco AS Kollsnes prosessanlegg, Gassco AS Kårstø prosessanlegg, Gasum LNG, Hammerfest LNG, NORSKE SHELL AS Sola, Nyhamna prosessanlegg, Stureterminalen, TWMA Norge Mongstad Base, Vask av offshoreutstyr PSW Group AS avd Mongstad.
[26] https://miljostatus.miljodirektoratet.no/tema/klima/norske-utslipp-av-klimagasser/klimagassutslipp-fra-olje--og-gassutvinning/ should be the same as SSB data but shows inconsistencies up to 20,000 tonnes per year
[27] https://info.offshorenorge.no/klimaogmiljorapport23/sec/6#report-top
[28] It is worth noting that there has since been an update of the GWP100 for fossil methane to 29.8 in AR6 https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter07.pdf

tonnes CO_2 equivalents (potentially larger than the remaining emissions of the target). There is a need for more transparency on what is and is not included in these definitions by the petroleum industry, and alignment on which numbers will be used for emissions targets. The facilities included in the targets should be made clear as they will likely require different decarbonisation technologies and R&D efforts.

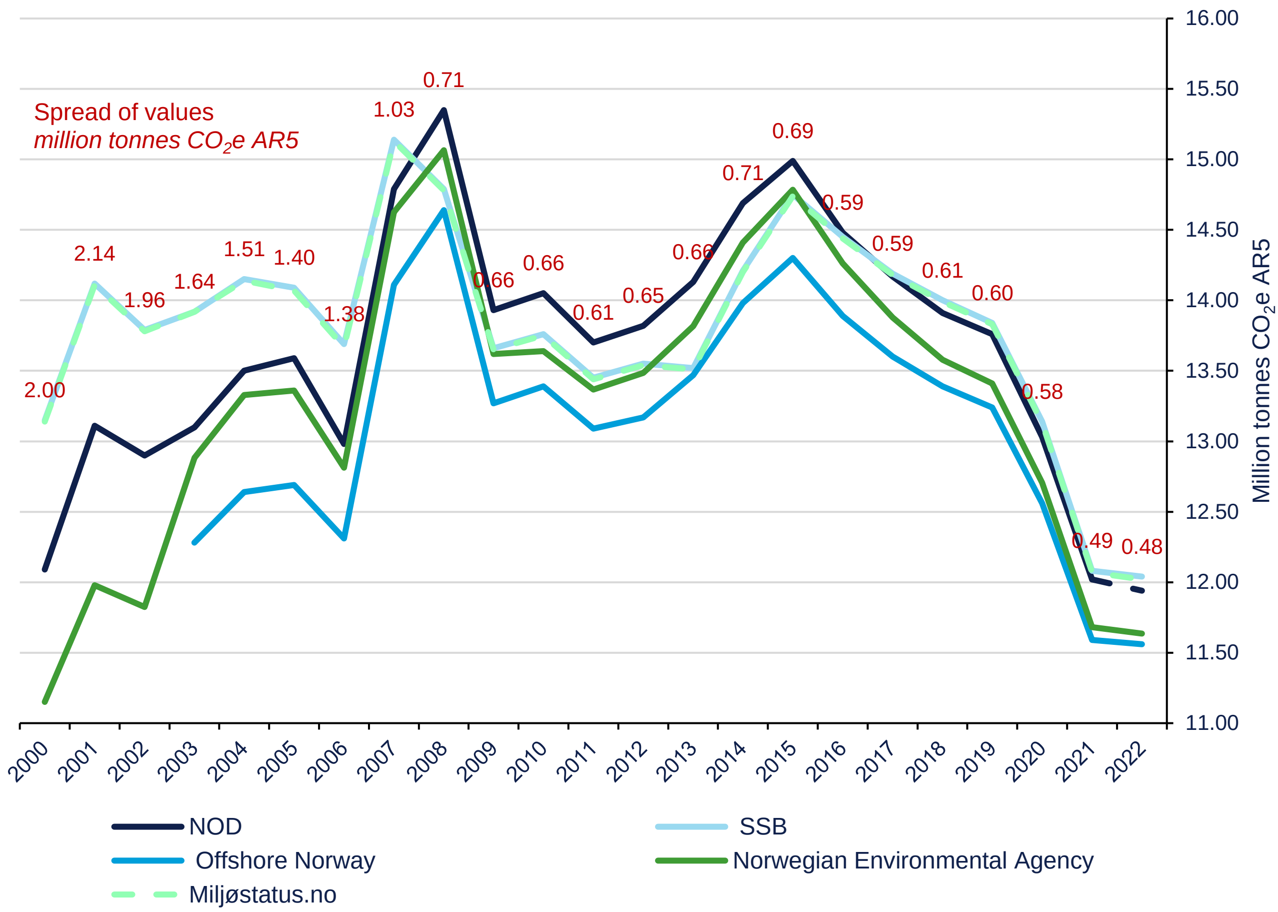

Figure 3-2: Emissions from the Norwegian petroleum sector (various sources)

The emissions from 2005 which are used for the reduction targets show a low value of 12.7 million tonnes CO_2 equivalents and high value of 14.1 million tonnes CO_2 equivalents. This puts the 2030 target at 6.4 – 7.1 million tonnes CO_2 equivalents and the 2050 target at 0.6 – 1.4 million tonnes CO_2 equivalents.

Figure 3-3 shows the total scope 1 emissions from the NCS (including onshore activities) in 2022 from SSB, categorised into activities and emission sources.

- Activity: In 2022, around 86 percent of total scope 1 emissions came from offshore assets, while 14 percent came from onshore activities.
- Emission sources: Fuel combustion in gas turbines is by far the largest source of emissions, accounting for 81 percent of total scope 1 emissions (69.5 percent from offshore activities and 11.6 percent from onshore facilities).

Note that the latest emissions data from SSB for the oil and gas industry for the year 2023 is labelled as confidential and cannot be accessed.

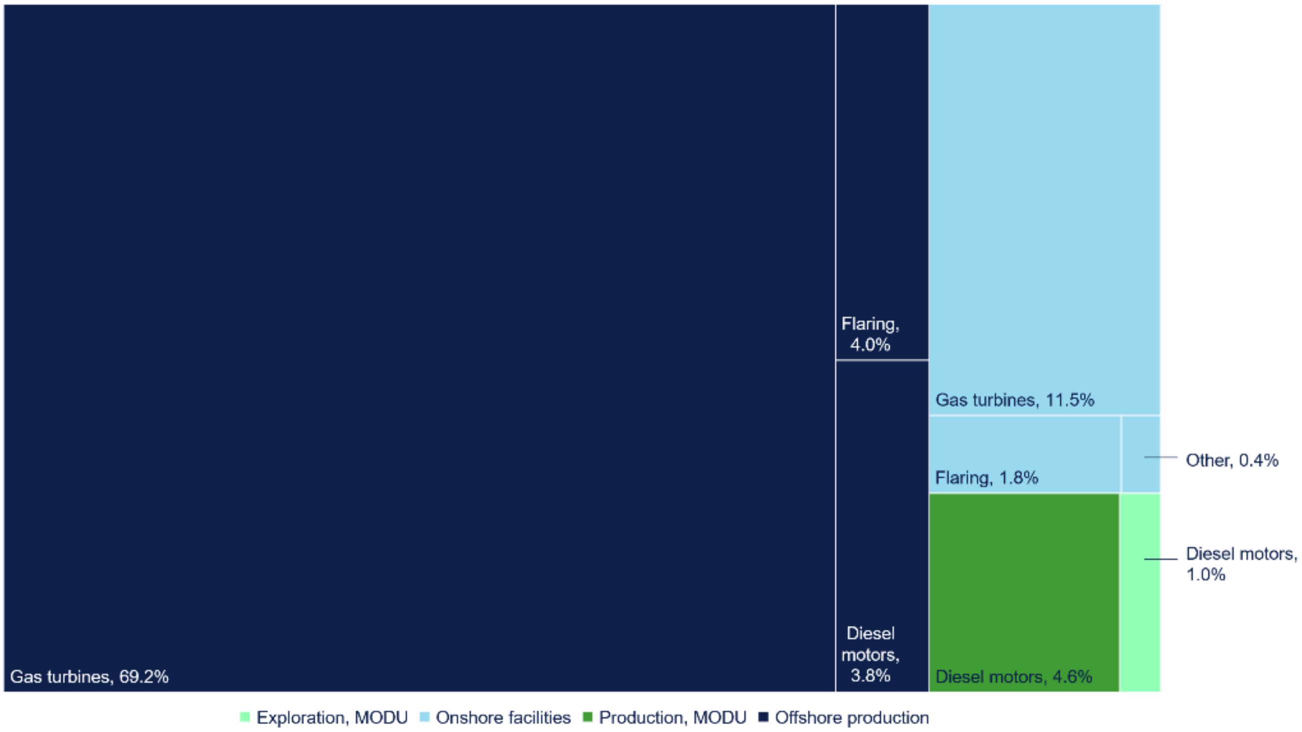

Figure 3-3: Scope 1 emissions from the Norwegian petroleum sector in 2022 from SSB table 13931[29], by emission source and activity (% of total CO_2-eq emitted). MODU stands for mobile offshore drilling unit.

Given that gas turbines contribute over 80% of scope 1 emissions, focusing on reducing emissions from turbines is crucial for achieving the 2050 target. With the goal of a 90-95% reduction, acknowledging that some residual emissions, such as those from flaring, may be difficult to eliminate entirely, it is important to explore strategies for fully mitigating turbine emissions. This can be achieved either by directly reducing the emissions from gas turbine combustion or by transitioning to electrical power. Additionally, focusing on energy efficiency to lower overall energy demand will be important. It is important to note that the scope 1 emissions split is not provided by region, and there are likely to be variations in the split between the North, Norwegian, and Barents Seas.

3.2.3 Norway is far from meeting its climate commitments

According to DNV's Energy Transition Norway (ETN) report from 2023, Norway is far from meeting its climate commitments on a 55% emission reduction in 2030 and 90-95% reduction in 2050. In 2022, emissions were only slightly less than in 1990 and our forecasts show emissions are likely to be reduced by 27% in 2030 and 80% by 2050[30]. This is in line with the recent estimates from the Norwegian State Budget, estimating an emission reduction of 26.4% by 2030 with today's policy[31].

The main factors contributing to DNV's estimated reduction in emissions are electrification of road transport and a general decline in oil and gas production, combined with using grid-connected electricity instead of gas-fired turbines to power remaining production.

For the petroleum industry, we forecast a 30% reduction in emission from 2022 to 2030. This translates to a 35-40% reduction from 2005-levels depending on your reference data (see also Chapter 3.2.2), which is the baseline year used

29 13931: Klimagasser AR5, etter kilde (aktivitet), komponent, statistikkvariabel, år og energiprodukt
30 DNV (2023): Energy Transition Norway
31 https://e24.no/energi-og-klima/i/63XxOQ/skivebom-paa-klimamaalet-en-svart-dag

by the industry. Looking at currently sanctioned measures, KonKraft forecasts an emission decline of 32%[32]. This is far from the industry target of a 50% reduction by 2030.

In 2050, DNV forecasts 84% emission reductions from the industry from 2022 levels – which is equal to 85-86% reduction from the 2005 baseline – and a 54% electrification rate on the energy used. This is in line with KonKraft's projections on emission reductions with currently sanctioned measures. Note that the DNV forecasts are based on a steep decline in Norwegian oil and gas production, with a remaining production of around 90 million Sm^3 o.e. per year in 2050. The higher production scenario assumed in this study results in higher emissions all else equal, and requires that more measures for decarbonizing the industry are put in place.

3.2.4 The future role of Norwegian oil and gas

As a significant exporter of oil and gas, Norway faces both challenges and opportunities within the energy transition. In the short-term, DNV expects production to increase, partly due to supply shocks associated with Russia's invasion of Ukraine. However, the landscape is shifting, with the long-term trend indicating a steady decline.

Towards mid-century, DNVs ETN expects production of oil to decrease due to increased global competition in a shrinking market which will put downward pressure on the oil price. Combined with relatively few new discoveries and a reduced investment appetite in pursuing production in challenging environments, we expect a steep decline in oil production from the NCS towards 2050: a reduction of 93% compared to today's level, reaching 0.2 Mbpd.

The picture is different for natural gas. With the European Union (EU) being a major market for Norwegian gas exports, the situation in the EU is of critical importance to the future market of Norwegian gas. Our forecasts show a short-term increase in European demand for Norwegian gas due to the Russian invasion, with Norwegian gas providing a reliable and relatively cleaner alternative to coal during the transition to renewables in the short- to medium-term. However, the demand is expected to decline in the long-term and more rapidly than previously estimated as EU accelerates its decarbonisation efforts. By 2050, Norway's gas exports are projected to decline by 35% (compared to today's level).

As the EU reduces its dependence on fossil fuels, Norway's role as an energy exporter will also evolve. DNV's ETN suggests that Norway could continue to be an important trade partner with Europe by diversifying its energy exports, particularly by increasing electricity exports derived from renewable sources and by developing a robust hydrogen export sector. This would align well with EU's dual goals of ensuring energy security and achieving decarbonization. However, the value of Norwegian energy exports is expected to decrease. DNV estimates that the value of Norway's energy exports in 2050 will be around half the value, or NOK 250bn/year lower, than the value realized on average over the last 10 years[33].

[32] KonKraft (2024): The Energy Industry of the Future on the Norwegian Shelf – Climate Strategy towards 2030 and 2050 – Status Report 2024
[33] DNV (2023): Energy Transition Norway

4 ESTABLISHING THE BASELINE: BUILDING A ROBUST ANALYTICAL FRAMEWORK

To re-iterate, the purpose of this study – as commissioned by OG21 – is to assess how Norway can achieve near-zero direct emissions from the NCS by 2050 through the implementation of technology and (potentially) new business models, while maintaining the high production levels projected by NOD in their high scenario.

To carry out this assessment, we have established an emissions baseline that sets the foundation for our further analysis as follows:

1) **Review of assumptions:** We first examine the key assumptions underlying NOD's high production scenario and their implications for emissions up to 2050. Where assumptions are missing, we have established reasonable assumptions based on available data.

2) **Establishing a baseline:** Based on these assumptions, we estimate the theoretical emission baseline through 2050 should no further emission reduction measures be implemented.

3) **Emission reduction potential:** We then assess how the introduction of new technologies and business models could reduce emissions from the baseline scenario.

In the next sub-chapters, we will explore steps 1) and 2), developing a theoretical emissions baseline for 2050. This baseline will serve as the foundation for understanding what is required in terms of emission reduction measures under a high production scenario to meet the 2050 targets. Step 3) accumulates to a roadmap, showing a potential pathway to near-zero and presented in Chapter 8.

4.1 NOD's high production scenario for the Norwegian petroleum industry

In 2024, the NOD released their updated resource report[34] which describes three scenarios of future oil and gas production from the Norwegian continental shelf. The three NOD scenarios are shown in Figure 4-1 below, alongside our Energy Transition Norway (ETN) 2023 results[35]. The red line shows NOD's high scenario that we consider in this report and use to establish the emissions baseline.

[34] https://www.sodir.no/aktuelt/publikasjoner/rapporter/ressursrapporter/ressursrapport-2024/
[35] https://store.veracity.com/energy-transition-norway-2023-dataset

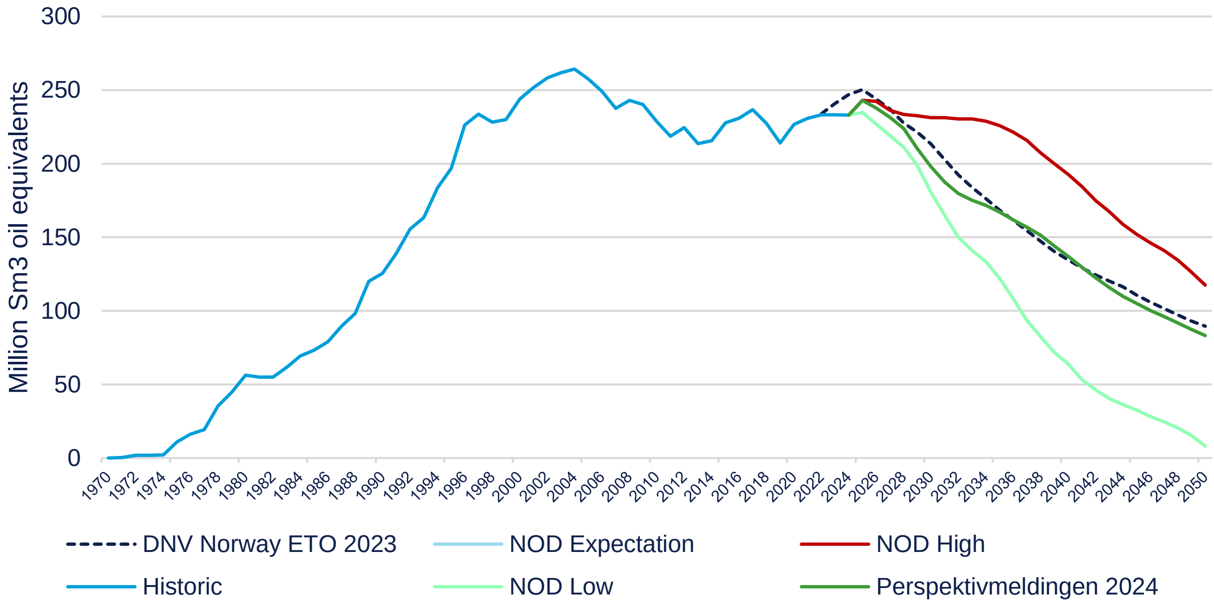

Figure 4-1: Historical production and future production scenarios on the NCS (NOD, DNV ETN 2023)

Even though only NOD's high production scenario has been considered as part of this study, it should be noted that DNV sees this as an unrealistic scenario, with our results from the ETN 2023 (presented in Chapter 3.2.4) being more in line with the expected scenario from NOD. The NOD expectation and Perspektivmeldingen 2024[36] are the same. The government-appointed Climate Committee recommends reducing petroleum activity beyond the expected level to not hinder the Norwegian transition to a near-zero society, which is more in line with NOD's low scenario[37]. NOD's high production scenario falls within the uncertainty range of the NOD's estimates of remaining resources on the NCS but exceeds the government's expectation for future production.

4.1.1 Assumptions behind NOD's high production scenario

DNV has not been given access to the full data and assumptions behind NOD's high production scenario. Therefore, only the publicly available information from the resource report[38] has been assessed. The key assumptions given in the resource report about the scenario are listed below:

1. *"Liquids and gas production will increase leading up to 2025 and stay at a high level over the next decade. Gas production will remain at a high level until 2037 and will then start to decline. An increasing share of production must come from undiscovered resources"*
2. *"As of 2025, production will be maintained over the next decade, followed by a gradual decline. Production will drop from about 245 million scm oe in 2025 to about 120 million scm oe in 2050"*
3. *"Multiple major discoveries will be made in the Barents Sea, for example in the western and central parts of the Barents Sea. These will be developed quickly. New and significant gas export capacity from the Barents Sea to the Norwegian Sea will be developed quickly. The major discoveries will lead to increased exploration. An increasing share of exploration wells will be drilled in the Barents Sea over the intermediate and longer term."*

[36] https://www.regjeringen.no/no/dokumenter/meld.-st.-31-20232024/id3049290/?q=olje&ch=3#kap3-2
[37] https://files.nettsteder.regjeringen.no/wpuploads01/sites/479/2023/10/Klimautvalget-2050.pdf
[38] https://www.sodir.no/aktuelt/publikasjoner/rapporter/ressursrapporter/ressursrapport-2024/

4. *"Increased exploration and more discoveries in mature areas will increase the value of existing fields and infrastructure. Discoveries being developed will maintain capacity utilisation on host fields, pipelines and process plants. Costs will be contained. Increased profits on existing fields will help extend production on the fields."*

5. *"All new, independent developments will be supplied with nearly emission-free power."*

6. *"One trajectory where all three scenarios have a basic price of USD 70/bbl, and one including price sensitivity of USD 95/bbl in high, and USD 45 in low."*

Along with these assumptions, there are several non-stated assumptions that are key to understanding the development of infrastructure and emissions as an effect of NOD's high scenario:

1. **Proportion of oil vs. gas:** This is key as emissions profiles and infrastructure requirements will be different depending on the proportion of these.
2. **A regional breakdown of production:** This will determine if production will mainly be tie-ins to existing infrastructure or if entirely new infrastructure is required.
3. **The proportion of small and large discoveries**: This is key to understanding the potential future infrastructure needs and therefore the expected associated emissions.
4. **How much of the production comes from existing fields and discoveries**: this is key for allocating the resource data and as we need to understand the decarbonisation potential for both greenfield and brownfield sites later in the assessment.

As we have not been given insights into these assumptions, we only consider oil equivalents without differentiating between oil and gas. We also assume that resources are developed in the proportions given in the resources data from NOD. This means that discovered resources are developed in each region according to the proportions in NOD's latest resource accounts[39]. We do not consider the size of discoveries as all calculations are done at the regional level. We assume based on the descriptions in NOD's resource report that NOD's low scenario consists entirely of discovered resources.

4.2 Emissions baseline towards 2050 under NOD's high production scenario

We developed a methodology to translate the high production numbers towards 2050 into an emissions baseline curve. This is key to estimate remaining emissions in 2050, which will then be used to quantify the emissions reduction measures required to reach the 90-95% emission reduction target. To be clear: this is **not** a forecast.

The following data was gathered:

1. Data on NOD's high production scenario[40]
2. Available assumptions on the high and low resource growth scenarios, as described in the resource report[41]
3. Historically reported emissions and production, see Chapter 3.2.2.
4. Data from NOD's resource accounts as per 31st December 2023[42]

[39] https://www.sodir.no/en/whats-new/publications/reports/resource-accounts/resource-accounts-2023/1--resource-accounts/
[40] Sheet "Fig. 4.7" here: https://www.sodir.no/globalassets/1-sodir/publikasjoner/rapporter/ressursrapporter/2024/no/ressursrapport-resource-report-2024-bakgrunnsdata-numbers.xlsx
[41] https://www.sodir.no/en/whats-new/publications/reports/resource-report/resource-report-2024/three-potential-scenarios-for-the-ncs-leading-up-to-2050/
[42] https://www.sodir.no/en/whats-new/publications/reports/resource-accounts/resource-accounts-2023/

4.2.1 Assumptions on future production

For the high and low resource growth scenarios, we made the following assumptions based on NOD's publicly available information:

- We categorise NOD's low scenario as "Discovered". This includes reserves, contingent resources in fields, and contingent resources in discoveries.
- We categorise the difference between NOD's high and low scenarios as "Undiscovered". This includes undiscovered resources.
- The contingent resources in fields that are not allocated to a specific area is split proportionally between the Norwegian Sea, North Sea, and Barents Sea based on the relative proportions of the "Discovered" resources.

The categories and data used are given in Figure 4-2.

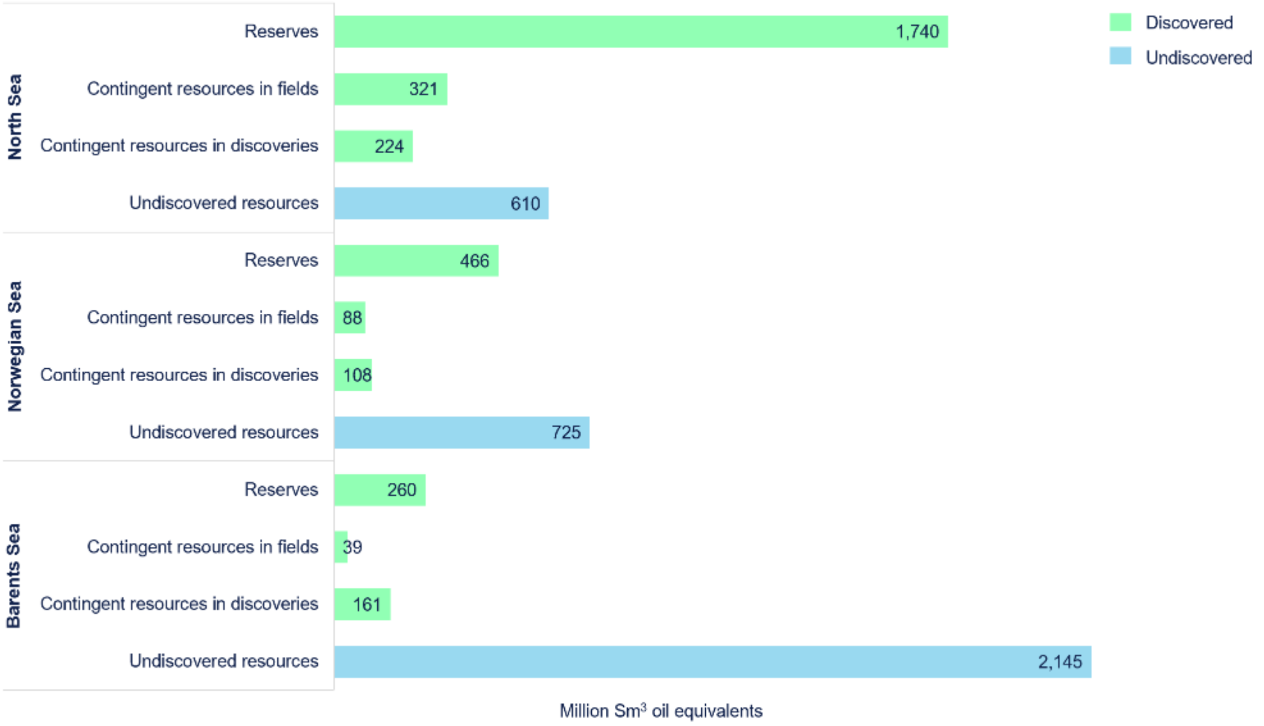

Figure 4-2: Original recoverable petroleum resources on the NCS, categorised into "Discovered" and "Undiscovered" resources[43]

Resources are allocated to each year of production in the scenario based on the relative proportions of each maritime zone. Once all these figures are added up and distributed, the "discovered" and "undiscovered" resources in the NOD resources report total more than the production in the NOD high scenario. This means there are enough resources to cover the production to 2050 in NOD's high scenario. Note that we are not considering the realism of the resources given in the report, as this is outside the scope of this work.

Figure 4-3 shows how our methodology distributes the discovered and undiscovered resources between the high and low scenarios by NOD, with the historic production for reference, while Figure 4-4 shows how the resources are split between the different areas (from 2025 out to 2050).

[43] Data from NOD resource accounts, as of 31st December 2023

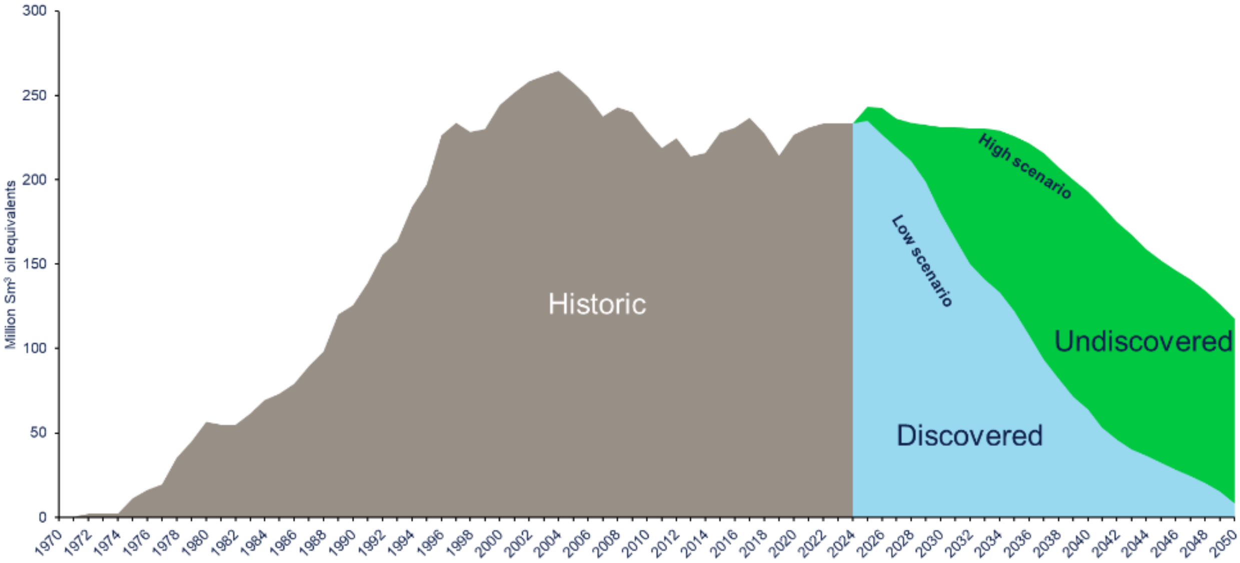

Figure 4-3: Depiction of historic and projected resources for NOD's low and high production scenarios. Our methodology separates future resources into currently discovered and undiscovered resources, based on the scenario.

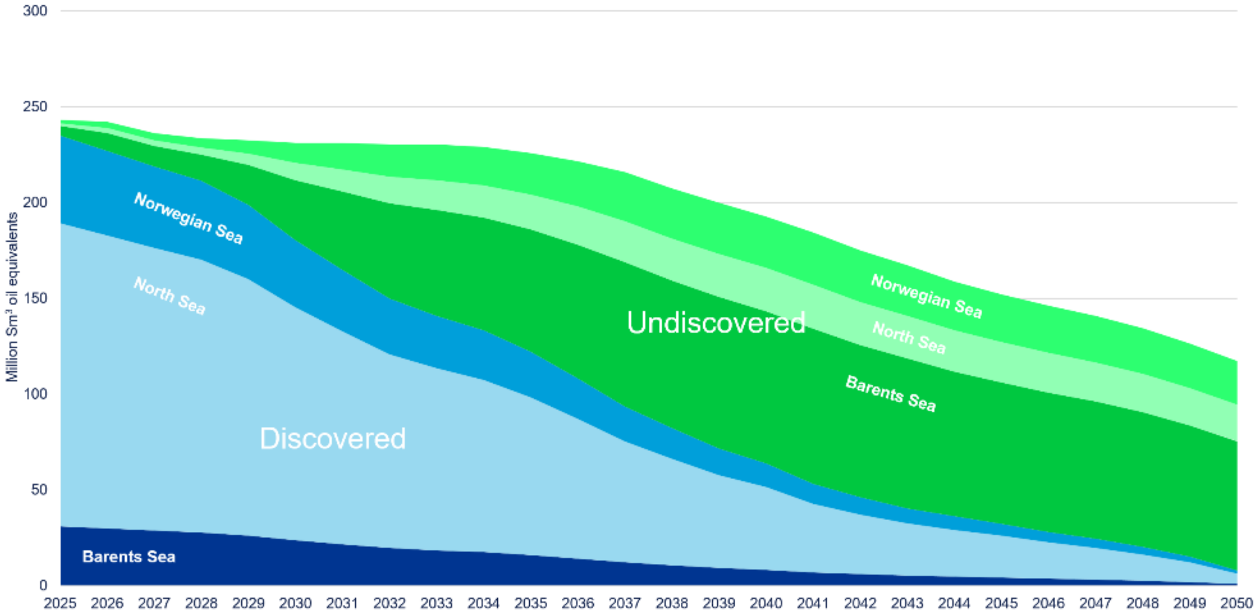

Figure 4-4: Modelled future resources distributed between maritime zones. Blue and green colours represent the exploited resources in the low and high scenario, respectively.

The above splits match well with the scenario's description from NOD[44], stating that the Barents Sea is expanded quickly and that discoveries in the North Sea and Norwegian Sea extend production.

[44] https://www.sodir.no/en/whats-new/publications/reports/resource-report/resource-report-2024/three-potential-scenarios-for-the-ncs-leading-up-to-2050/

4.2.2 Assumptions on emissions under NOD's high production scenario

To create a baseline for emissions towards 2050, we matched emission factors for each region with the future production for each region we calculated using NOD's high scenario. We did this on a regional basis as there are big differences between regions in terms of emissions per unit production.

We make the following assumptions on emissions:

- Average historical emission factors were used as a basis for estimating future emission factors within each region
- For the North Sea the average emission factor was calculated using available data from 1997 to 2023. This gave a factor of 54.8 kg CO_2 equivalents/Sm^3
- For the Norwegian Sea the average emission factor was calculated using available data from 1997 to 2023. This gave a factor of 44.7 kg CO_2 equivalents/Sm^3
- For the Barents Sea, the average emission factor was calculating using available data from 2019 to 2023 as these are likely more representative for the future than the extremely high emissions factors for the previous years, which are due to the Snøhvit field starting up. This gave a factor of 104.1 kg CO_2 equivalents/Sm^3
- Barents Sea emissions were significantly higher than the other regions, but it only has two operational developments. This was also checked against the newest development Johan Castberg. The figures for emissions and production for the lifetime of the field given in the PUD[45] result in an emissions factor of 108.7 kg CO_2 equivalents/Sm^3. Therefore, the emissions factor for the Barents Sea region is considered reasonable.

The historic emissions factors can be seen in Figure 4-5.

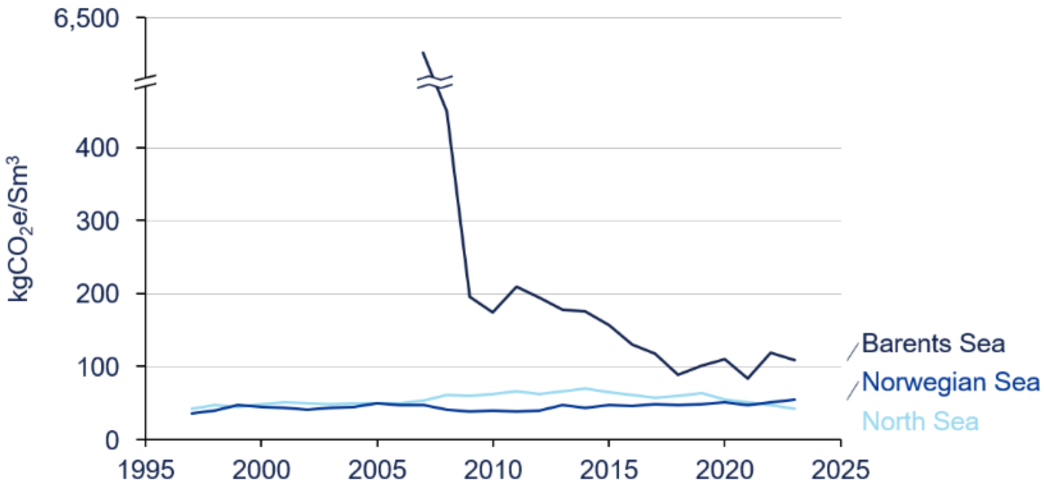

Figure 4-5: Historic emission factors from different maritime zones on the NCS.

4.2.3 Resulting emission potential towards 2050

The average emissions factors per region were then applied to the high production scenario for each region, with the resulting theoretical emissions towards 2050 seen in Figure 4-6**. It is important to note that this is not a forecast of expected future emissions,** and the figure should not be used in that context**.** The purpose of this methodology is to establish a baseline for the theoretical emissions potential in 2050 should no further decarbonisation measures take

[45] https://www.regjeringen.no/no/dokumenter/prop.-80-s-20172018/id2596504/?ch=3

place. This is critical in understanding the volume of decarbonisation measures required to reach the stated targets by the industry.

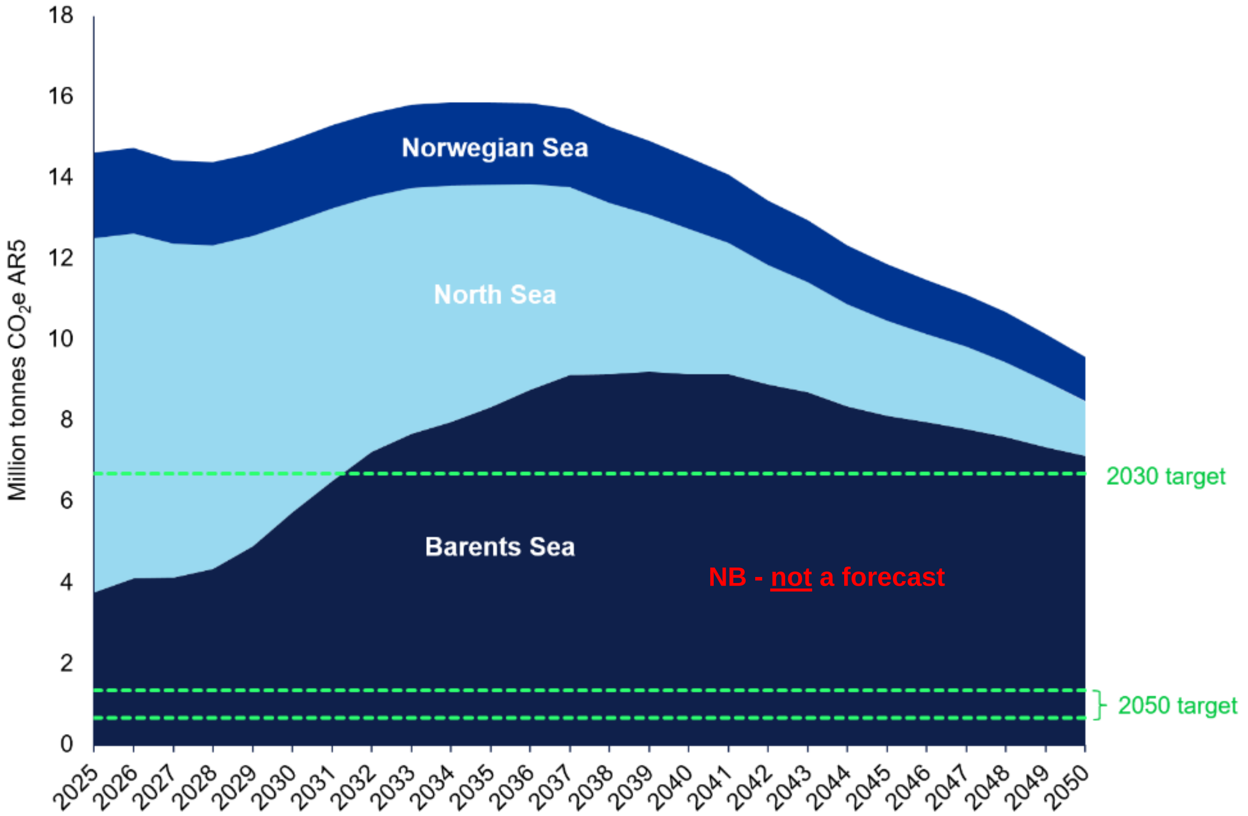

Figure 4-6: Results of the baselining emissions model. The dashed lines show the climate targets. Note that this is not a forecast of future emissions, but a theoretical emission potential from the sector should no further emission reduction measures be implemented.

The total emissions increase from today's levels (around 12 $MtCO_2e$) in this model for two important reasons. Firstly, the production increases sharply from today's levels in the high production scenario (see Figure 4-1). Secondly, the proportion of production from the Barents Sea is much larger than today, which combined with the higher emission factor results in higher total emissions in the baseline.

5 EVALUATING SOLUTIONS: TECHNOLOGIES DRIVING NEAR-ZERO EMISSIONS

To enable the Norwegian oil and gas industry to move towards near-zero emissions in 2050 in a cost-effective and scalable manner, electrification stands out as the primary measure, targeting the largest bulk of emissions from gas turbines. Although there are many ways to provide electricity to the installations, we have chosen to look deeper at three main options: power-from-shore, offshore wind, and gas-fired power hubs with CCS. Additionally, reducing emissions from drilling operations will be important, targeting a smaller yet important portion of the total emissions on the NCS.

Each of the technologies come with their own set of strengths and challenges. In the following sections, we will delve deeper into these topics, providing recommendations on R&D focus areas to ensure the technologies can scale sufficiently and cost effectively to enable near-zero emissions for the industry in 2050.

Overarching success factors

Although each technology comes with a different set of challenges and recommendations for R&D focus going forward, we have identified a few key factors for success towards the near-zero target that holds true for all:

- **Predictable, long-term policy frameworks are needed to ensure investment certainty and prevent delay in rolling out decarbonisation initiatives.** This is particularly evident for power-from-shore projects where debate continues over how to prioritize grid access between offshore oil and gas platforms and other industrial and societal needs, creating uncertainty. The need for a holistic energy plan with clear and predictable policy frameworks has also been highlighted in OG21’s 2023 Annual Report.
- **A coordinated electrification approach would offer several benefits.** Firstly, connecting multiple fields to a shared power source ensures optimal resource use, improved scalability, and significant cost savings. Secondly, integrating a stand-alone offshore power system with a grid connection ensures security of supply and a future-proof set-up: the grid connection will support the offshore power system’s efficient use as oil and gas production declines and even after the assets are decommissioned.
- **To tackle supply chain challenges and be fit for the future, R&D investments should prioritise initiatives with a broader market potential.** For example, subsea power grid technologies have historically been tied to the petroleum industry, constraining them to a smaller market. Piloting these applications in other industries, such as offshore wind, offers further opportunities for the technologies to mature and leverage economies of scale, thereby reducing costs.

Electrification pathways: Key findings

What are the main strengths and challenges, and where should R&D efforts be focused to reduce costs and accelerate implementation?

Power-from-shore

- **Strengths:** Proven technology offering a reliable and continuous power supply, historically seeing lower cost levels than other electrification measures. Already in use at both fixed assets and FPSOs and is especially relevant for installations near onshore infrastructure.
- **Challenges:** Limited grid capacity onshore necessitates large-scale build-out of new power generation to meet rising power demand – not only for offshore electrification. High voltage DC (HVDC) is required for long distance electrification, facing challenges related to available space for equipment, global supply constraints on cables and converters, and lower maturity for ship-based FPSO electrification.
- **R&D focus:** Develop modular, standardized HVDC equipment to improve supply chain resilience and cost-effectiveness. Innovate in subsea or compact equipment to reduce topside footprint. Further advance dynamic DC cables and DC turrets for ship-based FPSOs to enhance flexibility.

Offshore wind

- **Strengths:** Offers a renewable source of power which can be produced close to the assets, providing flexibility to remote locations further from shore. Both bottom-fixed and floating wind is proven and in operation globally, including in connection to offshore oil and gas assets. Combined with a cable to shore, the system can provide a continuous power supply while increasing power generation capacity connected to the grid.
- **Challenges:** Due to the intermittent nature of power production, back-up power is required to ensure continuous power supply. The emission reduction potential depends on the option selected, and zero-emission back-up solutions are less mature than conventional gas turbines. Due to deep water depths on the NCS, floating wind will largely be required, which has lower maturity and higher costs compared to bottom-fixed wind.
- **R&D focus:** Cost reductions for floating wind depend on standardized turbines, further innovation in floaters and mooring systems, and supply chain developments. Dynamic DC cables might be needed which are not yet mature. Off-grid solutions depend on further developments in zero-emission back-up systems, such as large-scale batteries and hydrogen storage.

Power hub with CCS

- **Strengths:** Offers a reliable and continuous power supply. Can be installed either as a stand-alone, floating unit to provide power to remote locations, or onshore (or near-shore). The latter will be similar to a power-from-shore solution, while potentially removing the barrier of limited onshore capacity.
- **Challenges:** The emission reduction potential depends on the capture rate, with current amine-based capture systems underperforming compared to the expected capture rate of 90%. While gas-fired power plants with CCS have been deployed onshore at the pilot scale, offshore units are not installed and see a lower maturity. Infrastructure for transport and storage of captured CO_2 will need to be available, which will be more challenging for offshore units. Further challenges include flow assurance, corrosion, and the high costs of the capture systems.
- **R&D focus:** Innovate in capture technology, especially promising novel capture methods, to improve efficiency, real-world capture rates, and reliability while bringing down costs. Further innovate on equipment design, such as modular and compact solutions for cost reductions and standardisation. Increase collaboration, learning, and knowledge sharing to avoid cost overruns and project delays. Further develop transport and storage solutions to reduce costs and increase availability of supportive CCS infrastructure.

Zero emission drilling: Key findings

What are the main strengths and challenges, and where should R&D efforts be focused to reduce costs and accelerate implementation?

- **Strengths:** Provides a pathway to minimise emissions from drilling activities, complementing the broader electrification strategy to reduce emissions from operations. Retrofit projects for low-carbon fuels are showing early success. Norway's stable, long-term contracted fleet supports smooth adoption of these technologies.
- **Challenges:** Retrofitting is more feasible than new builds due to extended construction times and financing constraints. Full electrification is limited by the need for long power cables, and biofuel supply faces challenges related to supply. Other low-carbon fuel alternatives present challenges such as toxicity, storage limitations, low maturity, and high costs.
- **R&D focus:** Retrofit kits for alternative fuels are key to transforming the existing fleet. Focus on improving rig efficiency to enable dual-fuel operations, and further pilot and test rig operations using alternative fuels. Increase availability of affordable, low-carbon fuel supply. Additionally, a coordinated push from government through available funding, and pull from operators through long-term contracts at favourable day rates, will be essential to justify investment in zero-emission upgrades.

5.1 Common challenges and synergies to electrifying oil and gas operations

Electrification is a key strategy for decarbonisation. While both power-from-shore, offshore wind, and gas-fired power hubs with CCS could all play an important role, the preferred pathway is case dependent. Despite distinct applications, they share some common barriers to large-scale deployment while offering important synergies. An integrated, system-wide strategy that addresses these shared challenges can enhance efficiency, reduce costs, and increase the likelihood of meeting 2050 targets. This coordination not only supports immediate decarbonisation goals but also enables a flexible, future-proof offshore energy system.

5.1.1 Key challenges across electrification pathways

Electrifying existing installations will be challenging

Electrifying existing (brownfield) installations is more complex and costly compared to new installations (greenfield). Brownfield assets face constraints from space limitations and the need to minimize operational downtime, making retrofits challenging and costly. Roughly half of the existing turbine load on the NCS is related to mechanically driving large equipment, which requires extensive modifications and downtime to replace[46]. Additionally, some assets recover waste heat from the turbines for gas processing, necessitating the installation of electrical boilers or heat pumps if full electrification is pursued. In contrast, greenfield projects can be designed for electrification from the start, reducing costs and complexities.

A full electrification under NOD's high production scenario would significantly increase power demand

[46] DNV (2022). Low-emission technologies to decarbonize the Norwegian petroleum value chain.

While we have not assessed the detailed timing of electrification across individual assets, we can outline the theoretical power demand for full electrification of the NCS as a whole to support discussions on the required scale and timing of electrification efforts. If full electrification were achieved by 2040[47], this would require a power demand of 28 TWh – nearly triple the current power consumption of 10 TWh. The demand reduces to 22 TWh in 2045 and 17 TWh by 2050. This high-level estimate highlights the scale of power required, although actual needs would vary by installation age, type, gas-to-oil ratio, water injection levels, and other factors.

Production shifts to more remote areas, which could increase complexity

Under the NOD's high production scenario, demand will shift increasingly towards undiscovered resources, especially in remote areas like the Barents Sea, where smaller, dispersed fields are located farther offshore. Electrification in these regions could be more complex and costly, requiring greater coordination between licensees to ensure optimal use of infrastructure. Additionally, the use of floating production units, such as Floating Production, Storage, and Offloading units (FPSOs), is likely to rise, adding further technological challenges to achieving full-scale electrification.

The global supply chain is constrained, although the level of constraint is technology dependent

Electrification at scale will put considerable demand on global supply chains, especially for specialized equipment such as high-voltage direct current (HVDC) cables and converters. This is particularly relevant for power-from-shore pathways but would also be important for any coordinated concept where an offshore power system, such as a wind farm or gas-fired power hub, is connected to shore. Additionally, many technologies require further technical development to meet the specific needs of offshore installations, such as reducing the footprint of equipment for platform retrofits.

Uncertainty in policy developments and priorities increase investor risk

Predictable, long-term policy frameworks are essential for securing the investments needed to advance electrification technologies. Policy debates, such as those concerning prioritization of grid access, introduce uncertainties that could delay project initiation and impact business case evaluations. To support the industry's decarbonization goals, clear policy alignment and incentives will be important. The need for a holistic energy plan with clear and predictable policy frameworks has also been highlighted in OG21's 2023 Annual Report[48].

5.1.2 Important synergies to electrification pathways

Cross-industry technology development can leverage economies of scale

Research and development initiatives that focus on solutions adaptable across multiple sectors can further reduce costs and enhance technical readiness. For example, subsea power grid technologies have historically been tied to the petroleum industry, constraining them to a smaller market. Piloting these applications in other industries, such as offshore wind, offers further opportunities for the technologies to mature and leverage economies of scale, thereby reducing costs.

A coordinated build-out presents several key advantages

Firstly, connecting multiple fields to a shared power source ensures optimal resource use, improved scalability, and significant cost savings. Secondly, integrating a stand-alone offshore power system with a grid connection ensures security of supply and a future-proof set-up: the grid connection will support the offshore power system's efficient use as oil and gas production declines and even after the assets are decommissioned.

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[47] The year 2040 is used as an example only. However, full electrification across all production in NOD's high scenario will likely not be feasible earlier, given existing challenges with electrifying large brownfield assets, potential supply chain constraints, and high associated costs.

[48] OG21, 2023, Årsrapport for 2023, og21-arsrapport-2023.pdf

5.2 Electrification pathway one: Power-from-shore

Power-from-shore has emerged as the primary electrification measure for Norway's offshore oil and gas operations, connecting offshore facilities directly to the onshore electricity grid. With high technological and commercial maturity, this approach offers a stable and flexible power supply, thanks largely to Norway's abundant hydropower resources.

Over the past decades, power-from-shore has gained significant traction, starting with the Troll A platform's electrification in 1996. Today, multiple installations across offshore and onshore sites are electrified. As of 2023, about 10 of the industry's 64 TWh energy consumption came from grid-supplied electricity, as seen in Figure 5-1. This leads to more efficient production[49] while also significantly reducing emissions. By 2030, this demand is expected to rise to 17 TWh if all planned projects are implemented[50].

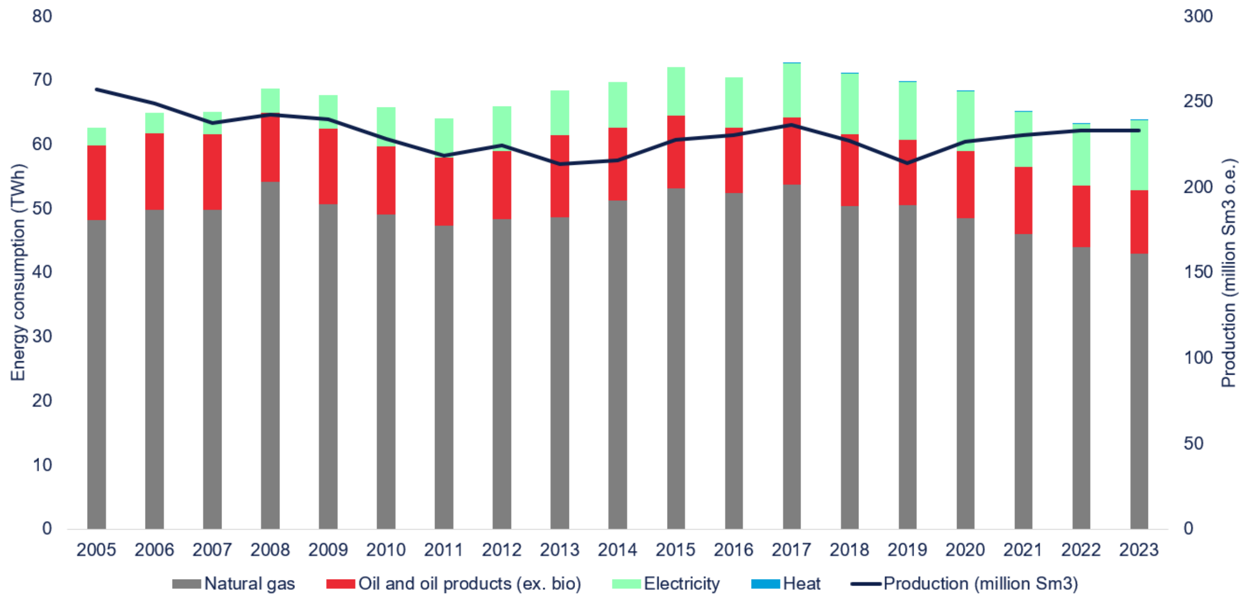

Figure 5-1: Historical energy consumption to produce oil and gas, including land-based facilities[51]

5.2.1 Design considerations and main challenges

For power-from-shore solutions, the choice of network design – whether individual or coordinated – and technology depends on factors such as distance to shore, power demand, and available platform capacity to host the equipment. An illustrative layout is shown in Figure 5-2.

Individual design: Each platform has a dedicated radial connection to the onshore grid. This approach is straightforward, with most existing projects using this approach. The drawbacks are potentially higher costs and sub-optimal network efficiency, especially if multiple radial connections are required along the coast.

Coordinated design: In this setup, multiple platforms connect to an offshore hub before linking to the onshore grid. This design reduces onshore landfalls, optimizes cable use, and allows for economies of scale. Though more complex, it offers long-term flexibility and supports future integration with offshore renewables, such as wind farms.

[49] The average energy efficiency lies between 90 and 98 percent for power-from-shore and between 25 and 40 percent for conventional gas turbines.
[50] https://www.energiogklima.no/nyhet/disse-feltene-far-kraft-fra-land-innen-2030
[51] https://www.ssb.no/statbank/list/energibalanse

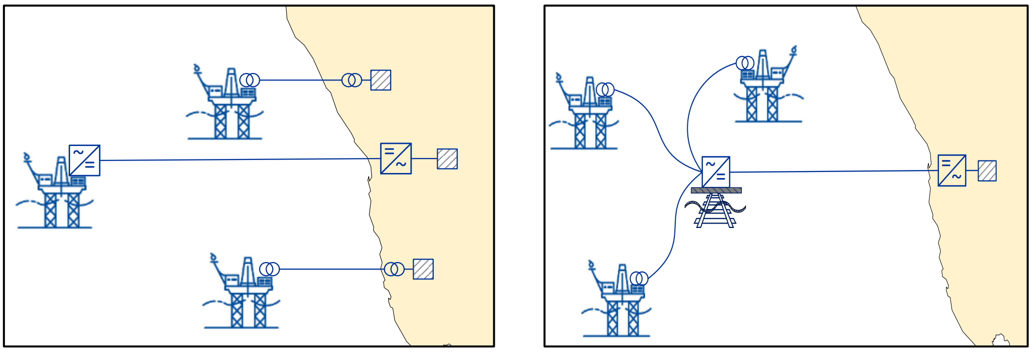

Figure 5-2: Illustrative layout of an individual (left) and coordinated (right) design approach[52]

5.2.1.1 HVDC is required for longer distances, but comes with challenges

High voltage alternating current (HVAC) cables are often used for shorter distances (under 200 km) due to its maturity and smaller footprint of equipment. The main drawbacks are higher losses (typically 5-7% per 100km), power limited by the cable rating (typically below 200MW), and the need for frequency converters to supply 60 Hz platforms. High voltage direct current (HVDC) technology overcome these, making it the preferred choice for longer distances. However, it has its own unique challenges, namely higher costs and a larger footprint for associated DC-to-AC converters – a key challenge for brownfield assets. Having a dedicated platform for the equipment and AC cables connected to the installations would solve these challenges but add to the total cost.

5.2.1.2 Electrification of FPSOs through DC technology is still immature

Electrifying FPSOs presents unique challenges due to their floating nature and the need for dynamic cables that can withstand movement and harsh marine conditions. Cylindrical FPSOs are proven through the Goliat FPSO in the Barents Sea, electrified through 100km AC power cables. FPSOs located further from shore would require a separate DC platform and AC turret, as DC turrets are an immature technology. Note that the electrification of cylindrical FPSOs through HVDC cables is not yet proven, although the Wisting concept is designed for this (though currently put on hold)[53]. For ship-shaped FPSOs, an additional challenge is that HVDC swivel technology is immature. This adds to the complexity and costs, as seen with the recently anchored Johan Castberg FPSO[54].

5.2.1.3 Supply chains are constrained, and costs are rising

The supply chain for offshore HVDC systems is under significant strain, leading to long lead times (up to 10 years) and substantial cost increases. There are two main reasons why:

1) The rapid global demand for low-carbon infrastructure – including cross-country interconnectors, offshore wind integration, and onshore power transmission – has caused a wave of demand for HVDC systems. For example, the number of Voltage Source Converter (VSC) HVDC projects[55] in submitted to the Ten-year

[52] DNV (2022). Low-emission technologies to decarbonize the Norwegian petroleum value chain.

[53] Electrification - Sevan SSP

[54] Johan Castberg was originally intended to be electrified with power-from-shore, but the plans were scrapped in 2016 due to high costs ascribed to the long distance from shore (around 200 km) and other technical challenges. The abatement cost at the time was estimated to 3900-4600 NOK/tonne CO_2 (in 2016-NOK). Source: https://www.regjeringen.no/no/dokumenter/prop.-80-s-20172018/id2596504/?ch=6

[55] Voltage Source Converter HVDC (VSC HVDC) is a more versatile and grid-friendly technology and has become the main choice for HVDC systems, particularly for offshore wind integration and power-from-shore projects.

Network Development Plan for the EU and UK this year was **more than four times** the number of projects commissioned between 1997 and 2023[56].

2) The market for HVDC converters and cables is dominated by a **few established suppliers**. The surge in demand has led to accumulated large order books, as seen in Figure 5-3. With limited delivery capacity, the lead times and costs increase.

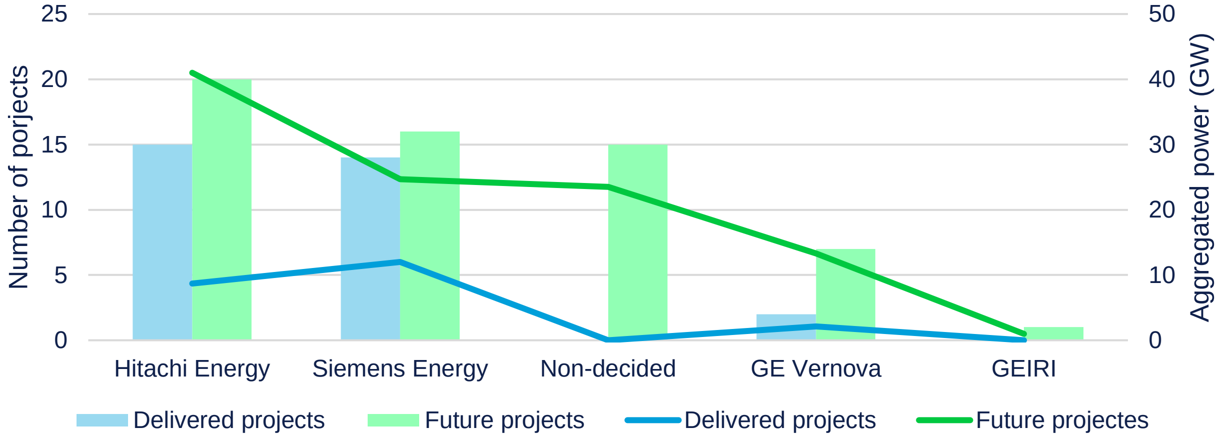

Figure 5-3 Number and aggregated power of delivered and (awarded) future projects per VSC HVDC supplier

Due to limited competition, the supply chain will likely remain strained in the near term. Chinese suppliers are largely excluded from OECD markets, and the prevailing "turnkey" contract model restricts smaller and niche suppliers from gaining market share. Although the established suppliers are expanding capacity to meet rising demand, the effect will likely not be seen before post 2030. Moreover, the suppliers might prefer to maintain a tight supply-demand balance to protect profit margins.

Consequently, the costs are increasing. For instance, recent 2GW@±525kV offshore HVDC systems report CAPEX costs between 1.3 and 1.7 M€/MW, significantly higher than our 2022 estimate of 0.9-1.3 M$/MW[57]. Although the "learning curve effect" suggests potential cost declines, current projections indicate that 2040 costs will be only 10% lower than 2024, due to ongoing supply chain pressures. Figure 5 4 shows the distribution of CAPEX for a typical power-from-shore project. Additionally, offshore HVDC systems are estimated to incur operational expenditures of 2-3% of CAPEX annually, adding 20-30% to the total CAPEX over their lifetime, not including power costs, which will further impact OPEX for oil and gas (O&G) assets.

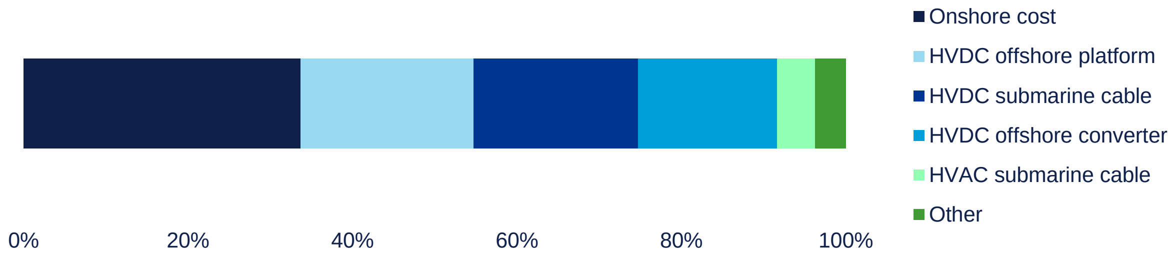

Figure 5-4: Distribution of CAPEX for a typical power-from-shore project

56 https://tyndp.entsoe.eu/resources/tyndp-2024-draft-portfolio; https://www.nationalgrideso.com/document/262681/download; https://www.nationalgrideso.com/document/304756/download

57 DNV, "Low-emission technologies to decarbonise the Norwegian petroleum value chain – OG21 deep dive study", September 2022

5.2.1.4 There is limited available onshore capacity

A major challenge for full electrification of Norway's oil and gas sector is the limited availability of power generation and grid capacity to meet increasing demand across industries.

Statnett's long-term market analysis projects a 70 TWh increase in demand by 2040[58], with 17 TWh attributed to the petroleum sector – though its share will be higher in earlier years. Meeting this demand will require at least 60 TWh of new production capacity, most of which won't be available until the 2030s or beyond. This delay is expected to create a temporary energy deficit by 2029 as demand growth outpaces supply[59], which could drive Norwegian power prices higher than in neighbouring countries, complicating the business case for power-from-shore projects. Similar projections by The Norwegian Water Resources and Energy Directorate (NVE) estimate a 56 TWh increase in demand by 2040, with comparable consumption for the petroleum sector of 17 TWh[60].

The impact of electrifying the oil and gas sector is more significant under NOD's high production scenario. If all production were fully electrified without added power capacity beyond Statnett's Base scenario, the energy deficit could persist beyond 2040, as illustrated in Figure 5-5. Achieving full electrification would require new capacity in line with Statnett's Extra High scenario, which depends on large-scale build-out of competitively priced, low-emission energy.

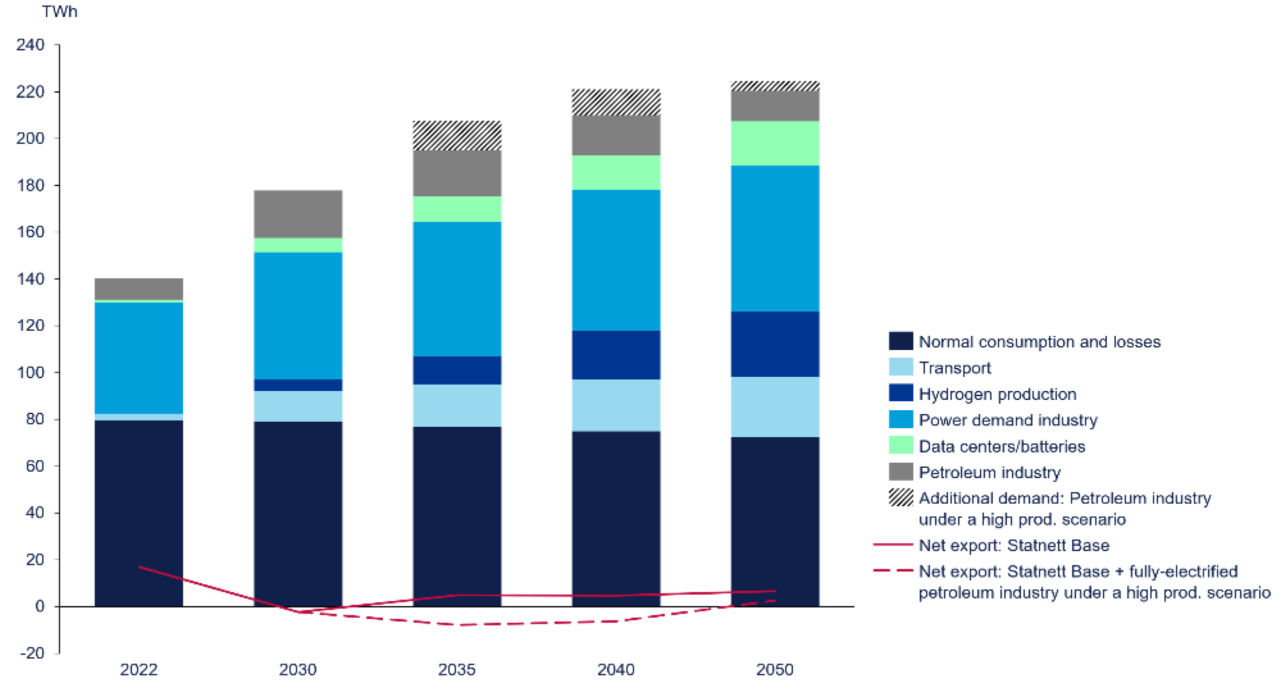

Figure 5-5: Power demand under Statnett's Base scenario and under a high production scenario vs. net export capacity

It is important to recognize that grid capacity challenges can vary across regions, although Statnett specifies that there is a need for new power production and expansions of the grid throughout the country. Co-locating new power generation and consumption would be beneficial, helping to maintain regional balance and possibly avoiding costly upgrades to the grid..

In summary, we want to emphasize the following key points:

58 Statnett (2023), Long-term market analysis 2022-2050
59 Statnett (2023), Forbruksutvikling i Norge 2022-2050 – delrapport til Langsiktig markedsanalyse 2022-2050
60 NVE (2023): Langsiktig kraftmarkedsanalyse

- Large-scale, low-emission energy at competitive prices is crucial for meeting Norway's demand growth through 2050 – especially under NOD's high production scenario. Without it, power prices will rise[61], and a full electrification of the petroleum sector might not be feasible.
- Co-locating new power generation and consumption can help maintain a regional balance and avoid costly grid expansions.
- Timing is crucial. Full electrification cannot realistically occur until sufficient power capacity is in place.

5.2.1.5 The political landscape is uncertain

The political landscape surrounding grid access and electrification is another major source of uncertainty. Debates continues over how to prioritize grid access between offshore oil and gas platforms and other industrial and societal needs, and public opposition has emerged due to rising electricity prices and concerns about the environmental impact of expanding grid infrastructure to accommodate oil and gas electrification projects.

Currently, energy supply solutions for the petroleum installations are considered as part of the authorities' approval of development plants, where power-from-shore must be evaluated. While the current government supports continued electrification, it emphasizes that renewable energy sources like offshore wind should be prioritized where possible. Notably, the Ministry of Energy has highlighted that regulatory approval for reconstruction projects involving power-from-shore will generally become more difficult, partly due to the potential strain on the onshore power grid[62]. In summary, this creates uncertainty in planning power-from-shore projects.

5.2.2 Focus areas and R&D action list for power-from-shore solutions

To overcome these challenges and enable cost-effective, scalable power-from-shore deployment, the industry can play a key role through targeted R&D and other important efforts. Below are a few selected focus areas, each with specific suggestions to actions the industry can take.

5.2.2.1 More compact DC equipment to minimise footprint

Goal: Reduce the costs and downtime of electrifying assets with DC technology by minimising the footprint of equipment. An example is DC Gas Insulated Switchgear (GIS), a compact solution requiring up to 95% less space compared with air-insulated switchgear. The technology is currently at TRL 7[63].

Suggested R&D actions:

- Further demonstrate long-term applicability of the technology by gaining more operating experience.
- Investigate alternative insulation gases to SF6.

Examples of ongoing initiatives: A DC GIS was deployed at the DolWin6 platform last year, reducing the size and weight of the platform by 10%.

[61] Statnett exemplifies this by modelling a 20 TWh increase in consumption by 2027 without added generation, pushing Norwegian electricity prices to match or exceed Germany's average of 80 EUR/MWh in all regions except NO4. This is a rise in prices by 30-40 EUR/MWh from their base scenario. Source: Statnett (2023), Forbruksutvikling i Norge 2022-2050 – delrapport til Langsiktig markedsanalyse 2022-2050

[62] https://www.regjeringen.no/no/aktuelt/godkjenner-ombygging-av-draugen-og-njord/id3020297/

[63] https://www.entsoe.eu/Technopedia/techsheets/dc-gas-insulated-switchgear-dc-gas-insulated-substation

5.2.2.2 Long-distance AC cables to reduce dependency on HVDC

Goal: Reduce the dependency on HVDC transmission for long distances and FPSOs.

Suggested R&D actions: Industry consensus suggests longer distance AC transmission needs major technology break-through.

Examples of ongoing initiatives: Low-frequency AC (LFAC) cables have recently been employed in long distance transmission of offshore wind power to the onshore grid[64]. The technology is currently suitable for distances up to 300 km and has been suggested for electrification of FPSOs in a study by Aker solutions[65].

5.2.2.3 Improve maturity of DC solutions for FPSOs

Goal: Enable cost-effective electrification of FPSOs located far from shore, as HVDC technology is still immature or unproven for these concepts.

Suggested R&D actions:

- Mature dynamic (flexible) HVDC cables required for floating vessels.
- Work to qualify existing HVDC swivel concepts required for ship-based FPSOs, through qualification programs.
- Develop HVDC connectors suitable for subsea applications, required for connect and disconnect purposes of ship-based FPSOs.

Examples of ongoing initiatives: The Wisting cylindrical FPSO is designed for full electrification through HVDC, although it is currently put on hold.

5.2.2.4 Subsea power grids for multiple offshore applications

Goal: Establish a scalable subsea grid that can serve multiple purposes – power offshore oil and gas assets, serve offshore wind farms and connect to a main power grid – to leverage economy of scale and reduce downtime for retrofits, while supporting long-term offshore electrification and reducing the strain on the onshore grid.

Suggested R&D actions:

- Further develop and test subsea components, such as subsea connectors.
- Develop and test the system integration of assets into a subsea power grid.

Examples of ongoing initiatives: SINTEF's SeaConnect, in collaboration with several operators and suppliers, is looking to develop high voltage subsea connections for resilient offshore grids[66].

5.2.2.5 Accelerate build-out of new power production

Goal: Increase the available capacity for power-from-shore projects by supporting the build-out of new, cost-effective power generation.

Suggested R&D actions:

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64 Electrification of Offshore Oil and Gas Production: Architectures and Power Conversion (mdpi.com)

65 Feasibility of the Electrification of FPSO Vessels Offshore Newfoundland and Labrador-IFI (energynl.ca)

66 https://www.sintef.no/en/projects/2023/seaconnect_high_voltage_subsea_connections_for_resilient_renewable_offshore_grids/

- Continue developing offshore production dedicated to electrifying oil and gas assets, while exploring opportunities for connection to the onshore grid. See Chapter 5.3 and 5.4 for more details on development needs for offshore wind and gas-power with CCS, respectively.
- Investigate opportunities for supporting the build-out of onshore power production.

Examples of ongoing initiatives: Several operators are investigating how to build new power generation connected to shore, also combined with electrification of offshore oil and gas assets.

5.3 Electrification pathway two: Offshore wind

Electrifying oil and gas operations using offshore wind power is emerging as a viable solution to reduce industry emissions by offsetting or fully replacing conventional gas turbines. Given that most fields are located in deeper waters (>60 meters), floating wind technology will likely be the main option. Today, floating offshore wind powers only a small fraction of platform energy needs through Hywind Tampen[67], and to DNVs knowledge there are no offshore wind projects directly linked to oil and gas platforms that have reached a Final Investment Decision (FID), though projects like GoliatVIND, supported by ENOVA, target construction around 2026/27[68]. The world's first floating wind development in Scotland has, however, performed with record high-capacity factors of 54%[69], showing promise. Looking ahead, offshore wind capacity for oil and gas electrification could see considerable growth as technology matures and costs fall.

5.3.1 Design considerations and main challenges

Electrifying oil and gas assets with offshore wind presents some specific design considerations, primarily centred around the configuration of wind power integration and the need for backup solutions. The choice of integration method – whether standalone, grid-connected, or through offshore hubs – depends on factors such as distance from shore, power requirements, and the available infrastructure for backup power.

- **Standalone with backup supply:** In remote locations with limited access to grid infrastructure, standalone offshore wind installations can supply platforms directly. Backup systems are required to ensure a stable power supply during low wind conditions. While Hywind Tampen uses natural gas turbines as back-up, this option will not provide the necessary emission reductions to reach the 2050 target. Instead, zero-emission solutions will be needed.
- **Grid-connected integration:** Offshore wind farms can connect to the onshore grid, ensuring a stable power source to platforms. This option, considered for projects like GoliatVIND and Ekofisk[70], allows operators to sell excess electricity to the grid during any surplus power production, supporting both operational flexibility and new revenue streams. For platforms not currently grid-connected, however, investment in grid infrastructure adds to the cost. Overall, this design requires careful coordination to ensure grid stability, especially during periods of high offshore wind production.
- **Offshore wind hubs:** A coordinated setup can link offshore wind farms to multiple platforms through a shared power hub, creating an efficient and scalable solution. These hubs could also connect to the onshore grid, forming a flexible power network that can serve both oil and gas installations and broader renewable energy needs. In the future, a meshed offshore grid could expand this approach.

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67 Startskuddet har gått for Norges havvindeventyr - Equinor
68 GoliatVIND | GoliatVind
69 Equinor (2021)
70 L. Sandvik (2024, May 22). Statnett mener Ekofisk kan få kraft fra land når det ikke blåser. *EnergiWatch*

Regardless of setup, offshore wind – especially floating – face some important challenges that need to be addressed to further mature the technology and reduce costs.

5.3.1.1 Maturity largely depends on floater concept

Unlike bottom-fixed wind – a commercially mature technology with a total of 35 GW installed across Europe as of 2024 – floating wind maturity lags behind and varies by floater concept. The spar and semi-submersible floater designs are the most mature, achieving TRLs of 8-9[71], with around 200 MW installed globally. Full commercialisation is expected by 2035. Tension-leg platforms (TLPs) are less mature, at TRLs 7-8[72] with a 25 MW demo project installed. Barge designs are less mature, but expected to advance in the near term through targeted R&D.

5.3.1.2 Dynamic cables and mooring systems need development

Floating wind projects require advanced dynamic inter-array and export cables to handle the movement and load conditions specific to offshore installations, facing some of the same challenges as electrification of floating FPSOs. While dynamic inter-array cables are commercially available, high-voltage dynamic export cables are not yet fully developed or deployed, especially for DC applications. There is also a need for optimised acceptance criteria for dynamic cables for floating wind, as today's requirements are mainly based on structures that are not necessarily representative, such as umbilicals. Moreover, the mooring system for floating wind turbines experience high loading from both operational and idling conditions, with a need for alignment on procedures and requirements to achieve an appropriate safety level.

5.3.1.3 Floating substations require special equipment

Offshore substations serve as crucial hubs for scaling floating wind farms, connecting multiple turbines and transmitting power to shore. However, developing floating substations to handle the movement of floating platforms is challenging, requiring specially designed cables and electrical equipment. While the DNV JIP on floating substations is addressing these needs, floating substations might not be necessary for smaller oil and gas platform electrification projects where fewer turbines and shorter distances are involved. For example, the GoliatVIND project plans to use a subsea substation[73].

5.3.1.4 Larger turbines have scaling challenges

The trend towards larger floating wind turbines (15 MW+) can reduce cost per energy output, but introduces new technical challenges. Larger, stiffer turbines can face resonance issues due to natural frequencies approaching the blade rotation frequency. Addressing these issues in floater design is essential to enable cost-effective scaling and stability for large floating wind farms.

5.3.1.5 Zero-emission offshore back-up systems are immature

Compared to conventional gas turbines, zero-emission offshore back-up systems – such as batteries and hydrogen systems – are immature.

- **Battery storage systems** are the most mature option, seeing high learning rates and falling costs. However, the storage duration is limited, and the footprint can be significant (depending on capacity). To DNVs

[71] Pre-commercial wind farm with full-scale turbines have been installed

[72] Demo project with full-scale turbine have been installed

[73] [DeepWind - INTOG GoliatVIND 75MW demonstration project in Norway (offshorewindscotland.org.uk)](#)

knowledge, no battery systems have been applied to offshore wind projects yet, although there are some ongoing initiatives aiming at integrating onshore battery storage with offshore wind farms. Examples include Ørsted's Hornsea 3[74] and RWE and TotalEnergie's OranjeWind, where the latter will include a 7.5 MW/11 MWh battery system operational by 2027[75].

- An alternative to batteries offering longer-duration storage, are **hydrogen-driven systems**. The production of hydrogen through electrolysis is a mature technology, and commercial tenders have opened for offshore hydrogen production from offshore wind in both Germany and the Netherlands[76]. However, there are some drawbacks. As the oil and gas assets rely on the electricity output of the system, the hydrogen would need to be converted back to usable power during hours of low wind output. The total system efficiency of producing and re-converting hydrogen to electricity is low, between 20 to 40% depending on choice of technology.

5.3.1.6 Supply chain limitations are a key risk

The offshore wind sector faces similar supply chain issues as other electrification projects, along with unique challenges that increase project cost and add complexity, resulting in high uncertainty and investor risk.

- **Limited supplier base and long team times:** The offshore wind industry is still growing, and the qualified supplier base for key components like turbines, floating platforms, and dynamic cables is limited. Combined with high demand, the result is long lead times and delay in project implementation. Bottlenecks in the supply of essential materials, such as rare metals for turbine magnets and semiconductors, add to delays.
- **High costs and volatile pricing:** Supply chain disruptions and high demand for steel, copper and other essential metals has led to increased costs of materials. This affects the overall project economics, making offshore wind projects even pricier. See more information on costs projections below.
- **Capacity constraints:** As offshore wind projects expand globally, competition for specialized installation vessels, heavy-lift cranes, and skilled labour has intensified. This leads to delays and increased costs – especially for floating wind systems which require advanced anchoring and mooring systems.
- **Port limitations:** To assemble the floating system, you need ports with deep quays and ample storage space. May local ports lack the necessary port capacity, and extensive modifications could be required.
- **Lack of standardisation:** A lack of standardised equipment and design specifications across the industry hinders the scalability of offshore wind solutions. Customizations for different projects, such as those integrated with oil and gas platforms, can complicate logistics and increase costs.

5.3.1.7 The costs of floating systems are high, but expected to decrease

The cost estimates in this section are based our latest Energy Transition Outlook (ETO) from 2024, updated with recent market insights and stakeholder feedback.

As a relatively new industry with limited experience and supply chains, as well as higher material requirements and fewer economies of scale compared to bottom-fixed installations, the cost levels are higher. For instance, floating structures need more than twice the steel mass (over 2000 tonnes) of bottom-fixed structures for equivalent 8 MW turbines, in addition to more material for anchors and mooring systems. Moreover, the floating structures are more complex to design and fabricate. The CAPEX is largely driven by floaters, moorings, and turbines[77], with our European

[74] https://orsted.com/en/media/news/2024/06/orsted-invests-in-battery-energy-storage-system-co-1390267511
[75] https://www.offshorewind.biz/2024/09/09/rwe-installing-ultra-fast-battery-storage-in-netherlands-part-of-oranjewind-offshore-wind-project/
[76] https://www.hydrogeninsight.com/production/tender-for-500mw-offshore-green-hydrogen-project-in-north-sea-announced-by-dutch-government/2-1-1422681
[77] The turbines used for floating wind are typically the same turbines used for bottom fixed, with modifications in the control system and potentially strengthening of the tower.

average estimated to be 6.4 MEUR/MW in 2024, dropping to 4.5 MEUR/MW by 2040 (see Figure 5-6). The key factors driving down costs include larger turbines, optimized floater and mooring designs, supply chain improvements, standardization, and risk reduction.

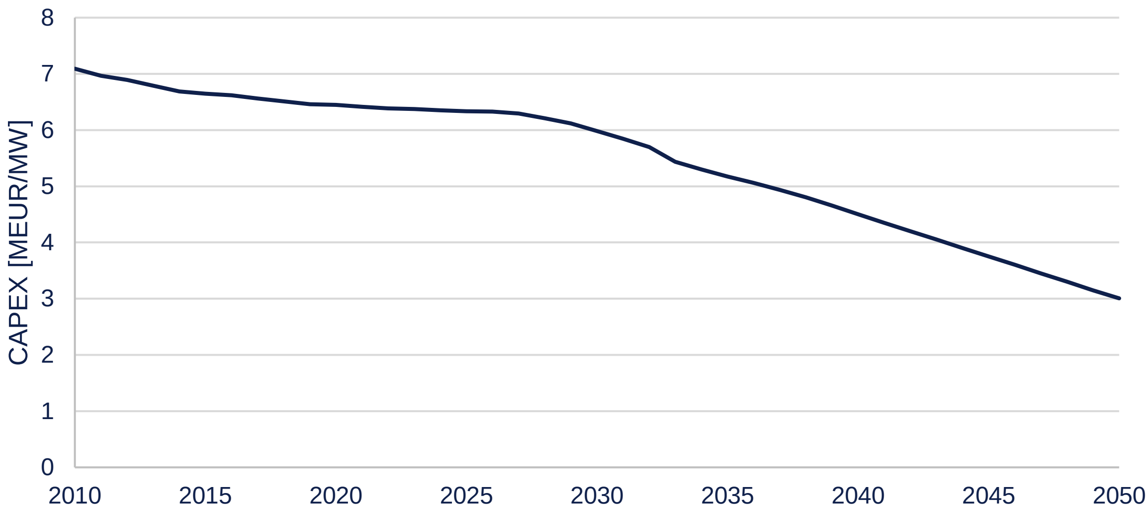

Figure 5-6: Total CAPEX for floating wind from 2010-2050 (European average)[78]

OPEX for floating wind is also higher than bottom-fixed due to the more complex foundation and station-keeping needs, as well as major component replacements often requiring towing to shore. While OPEX is expected to be significantly higher in the short term due to small project sizes and risk premiums, long-term OPEX is projected to follow a similar cost trajectory as bottom-fixed wind. A small markup is still expected for additional maintenance needs due to the wind farms being further from shore and in harsher environments. See Figure 5-7 for our projected OPEX trends to 2050.

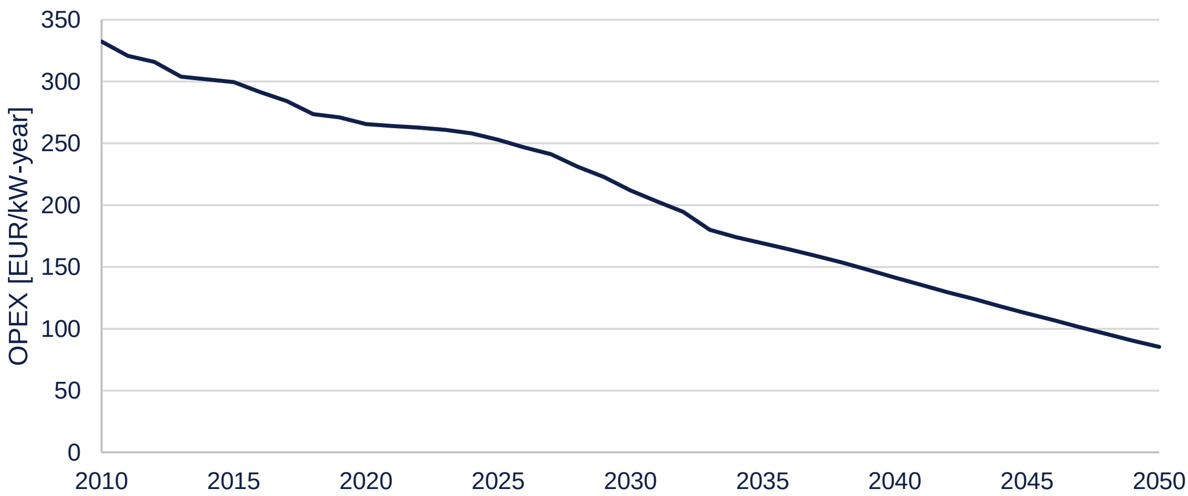

Figure 5-7: OPEX for floating wind from 2010-2050 (European average)[79]

[78] DNV (2024): Energy Transition Outlook. Note that an exchange rate of 0.98 USD to EUR has been applied.
[79] DNV (2024): Energy Transition Outlook. Note that an exchange rate of 0.98 USD to EUR has been applied.

In 2024, the Levelized Cost of Energy (LCOE) for floating wind in Europe is assumed to be around 2.5 times that of bottom-fixed (288 EUR/MWh vs. 112 EUR/MWh). However, we expect the LCOE to decrease by 75% by 2050, reaching around 75 EUR/MWh – still about 40% higher than bottom-fixed costs. Comparing projections by NVE, who calculate a cost of 140 EUR/MWh in 2030 for Norway[80], with our European average of 255 EUR/MWh for the same year, underscores the uncertainty in future estimates and the importance in assumptions made[81]. It should be noted that the LCOE projections have significantly increased from this year's ETO compared to last years' version due to the challenges related to floating wind developments seen globally. See Figure 5-8 for the full LCOE forecast.

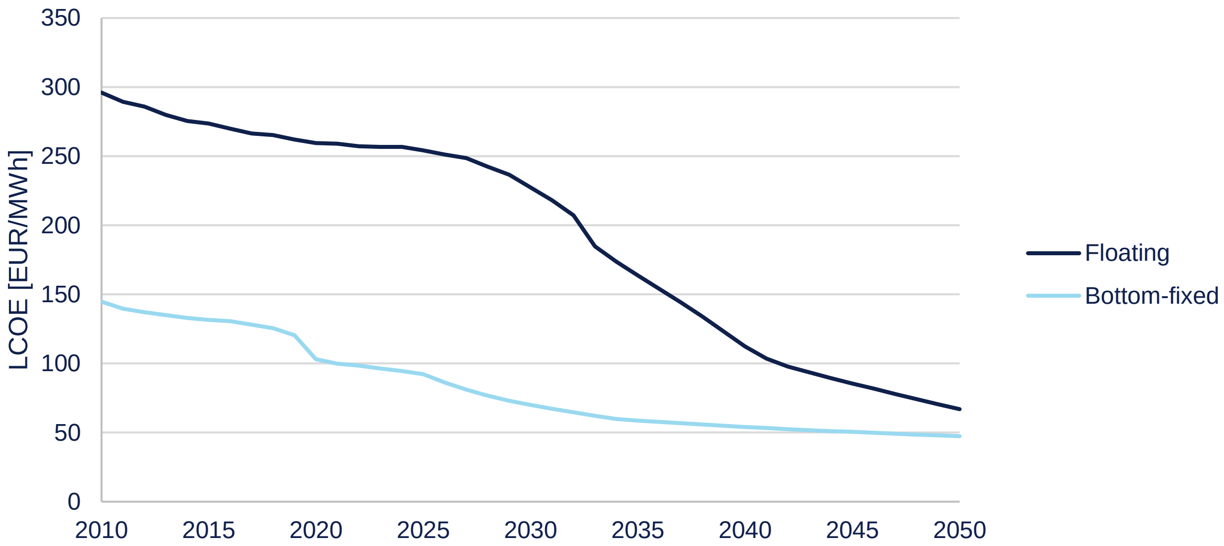

Figure 5-8: Levelized cost of energy (LCOE) before support for offshore wind (European average)[82]

5.3.2 Focus areas and R&D action list for power-from-shore solutions

To overcome these challenges and enable cost-effective, scalable power-from-shore deployment, the industry can play a key role through targeted R&D and other important efforts. Below are a few selected focus areas, each with specific suggestions to actions the industry can take.

5.3.2.1 Dynamic cable and mooring system reliability

Goal: Develop high-voltage dynamic cables and robust mooring systems capable of managing the unique load demands and movements of floating wind farms, particularly for long-distance power export (>110 km).

Suggested R&D focus:

- Testing of high-voltage dynamic cables in real-world offshore conditions to validate performance and durability, aligning with efforts towards floating FPSOs to ensure cost-efficiency.
- Establish industry-wide standards for mooring systems to manage load requirements and maintain safety.
- Align on technical specifications for dynamic inter-array cables and mooring systems, suitable for commercial floating wind farms.

80 https://www.nve.no/energi/analyser-og-statistikk/kostnader-for-kraftproduksjon/

81 For example, NVE uses a lower discount rate of 6 percent in their LCOE calculations, while we use a discount rate of 8.5 percent.

82 82 DNV (2024): Energy Transition Outlook. Note that an exchange rate of 0.98 USD to EUR has been applied.

Examples of ongoing initiatives: The ongoing DNV Floating Wind Reliability Joint Industry Project (JIP)[83] aims to optimise design requirements for dynamic inter-array cables and mooring systems, as well as establish consistent design philosophies and analysis methodologies for commercial-scale projects.

5.3.2.2 Scaling for larger turbines

Goal: Support stability and performance of floating wind systems with turbines over 15 MW by maturing floater designs and addressing tower resonance and structural stability issues.

Suggested R&D focus:

- Develop floater designs compatible with stiffer towers to prevent resonance issues.
- Conduct field tests on next-generation floaters with larger turbines (15 MW+) across varied offshore conditions.
- Set performance benchmarks and safety protocols to ensure stability in large floater-turbine configurations.

Examples of ongoing initiatives:

- The Norwegian Marine Energy Test Centre (METCentre) has partnered with several companies to test next-generation floaters with turbines above 15 MW, advancing design stability and integration capabilities[84].
- Floater designers, such as Principle Power[85], are working on floater adjustments to accommodate larger, stiffer towers, aiming to ensure stability and reduce risks associated with scaling.

5.3.2.3 Offshore substation and platform integration

Goal: Mature alternative platform concepts for power transfer from floating wind farms to suit different conditions.

Suggested R&D focus:

- Further develop cable and equipment designs that accommodate the movement of floating platforms.
- Establish standards and guidelines for floating substations.
- Demonstrate applicability of innovative subsea substations in connection to floating offshore wind.

Examples of ongoing initiatives:

- The DNV JIP on floating substations – currently in its second phase – aims to create standards and guidelines to address design and integration challenges.
- The GoliatVIND project explores the use of subsea substations for shorter-distance transmission, providing an adaptable model for similar offshore applications.
- Aker Solutions has signed an agreement with the METCentre to test its Subsea Collector, a subsea substation designed for floating offshore wind farms that reduces the length of cables required and the installation needs[86].

83 https://www.dnv.com/article/optimizing-mooring-and-dynamic-cable-design-requirements-for-floating-wind-245037/
84 15+ MW Floating Wind Turbines to Be Tested at Norway's METCentre | Offshore Wind
85 Principle Power unveils centre-column platform designs as floating wind towers stiffen | Recharge (rechargenews.com)
86 https://www.northwindresearch.no/news/aker-solutions-to-test-worlds-first-subsea-power-distribution-system/

5.3.2.4 Mitigate supply chain constrains

Goal: Overcome supply chain bottlenecks associated with floating wind.

Suggested R&D and other focus areas: In addition to what has been highlighted above, focus could be given to

- Investing in modular, standardised floater designs to simplify manufacturing and assembly logistics and reduce costs.
- Investing in local manufacturing facilities for critical components – such as turbines, cables, and transformers – which could support supply chain resilience and reduce dependency on global suppliers.
- Improving the efficiency for transport and installation (T&I) of floating units.
- Innovation in materials and recycling capabilities to reduce reliance on virgin materials.
- Forming strategic partnerships with key supplier and adopting innovative contracting strategies to secure components and reduce supply chain risk

Examples of ongoing initiatives:

- The Windsteel Technologies Joint Venture between Odfjell Oceanwind and manufacturing company Prodtex is addressing manufacturing constraints specific to floating wind.
- DNV has initiated a JIP on pioneering T&I techniques for floating wind foundations. The aim is to improve the efficiency of T&I, propose guidelines to enhance vessel capacity, and recommend key foundation design parameters. The work will kick off end of 2024 and conclude in 2026[87].

5.3.2.5 Maturing zero-emission backup solutions

Goal: Mature zero-emission backup solutions, such as battery storage and hydrogen systems, to ensure reliable power supply from stand-alone floating wind farms.

Suggested R&D focus:

- Mature large-scale battery storage system concepts for offshore environments.
- Advance offshore hydrogen production and storage solutions.
- Further develop efficient reconversion of hydrogen to electricity, e.g. through fuel cells.
- Improve the integration of hybrid battery-hydrogen systems that combine rapid response times with long-duration backup capabilities.

Examples of ongoing initiatives:

- The Brage Havvind floating wind farm proposed to include a 3 MWh battery storage unit connected to the floater. Unfortunately, the project did not receive support from Enova, and has to DNVs knowledge been put on hold[88].
- The Dolphyn Concept by ERM investigates producing hydrogen at a floating wind unit. The trial was launched this year in Wales, aimed to test the hydrogen production in a marine environment[89].

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87 https://www.dnv.com/article/pioneering-transportation-and-installation-techniques-for-floating-wind-foundations/
88 https://energiwatch.no/nyheter/offshore/article16927514.ece
89 https://www.offshorewind.biz/2024/07/03/uks-first-offshore-hydrogen-production-trials-kick-off-in-south-wales/

- The Deep Purple pilot, led by TechnipFMC[90] and with support from the Norwegian Research Council, is testing the full offshore hydrogen system: producing hydrogen offshore from wind, storing it on the seabed, and reconverting it back to electricity using fuel cells. This will provide valuable insights into hydrogen's potential as a reliable zero-emission backup for wind-powered electrification projects.

5.3.3 Regulatory actions and strategic measures to accelerate offshore wind implementation

Europe's ambitious offshore wind targets – 60 GW installed by 2030 and 300 GW by 2050 – demonstrate the region's commitment towards a renewable power system. Norway has set its own 30 GW target for offshore wind concessions by 2040, signalling support for industry growth. However, achieving this target will require clear regulatory frameworks and strategic focus.

5.3.3.1 There is a need for a national roadmap and clear regulatory framework

To accelerate offshore wind deployment, a national roadmap with supporting frameworks is essential to provide clear direction for the industry. Streamlining the license and application processes is critical to overcoming current delays. Reviewing and strengthening the capacity for project approvals, as well as opening new license areas, will help ensure Norway can meet its offshore wind ambitions and support its usage towards electrifying the petroleum sector. Moreover, clear policies on support mechanisms, taxation, and future connections to the onshore grid are necessary to provide investors and operators with the certainty needed to move forward.

In the EU, initiatives such as "go-to zones" proposed under the Renewable Energy Directive – Recast to 2030 (REDII) aim to speed up development by designating priority areas for renewable projects. Norway has not yet implemented REDII, which creates uncertainty for the industry.

5.3.3.2 Utilizing existing licenses can accelerate implementation

To fully realize offshore wind's potential for oil and gas electrification, regulatory clarity is crucial, particularly in overlapping licensing areas between O&G and offshore wind. Leveraging existing license areas to electrify oil and gas assets could offer a solution to kickstart offshore wind on the NCS while dedicated wind licenses are developed. These smaller-scale projects present an opportunity for Norway to establish itself as a competitive player in the floating offshore wind markets – developing our industry, strengthening our local supply chain and upskilling our workforce – while gathering valuable insights on integration and operational challenges.

5.3.3.3 Environmental and societal considerations need to be maintained

While offshore wind is seen as an important measure for emissions reduction, there is public concern about its potential impact on marine ecosystems. Small-scale electrification projects using offshore wind can provide important environmental learnings that could guide the design, installation, and operation of larger-scale wind farms to minimise ecological disruption. Monitoring environmental impacts at this scale offers a foundation for responsible offshore wind development that aligns with both industry and environmental goals.

[90] https://www.technipfmc.com/en/what-we-do/new-energy/hydrogen/deep-purple-pilot/

5.4 Electrification pathway three: Gas-fired power hub with carbon capture and storage (CCS)

Gas-fired power plants with CCS offer an additional electrification pathway with unique advantages and disadvantages compared to power-from-shore and offshore wind. This approach can be implemented as a stand-alone offshore unit located near oil and gas assets or in connection to the onshore grid, potentially supplementing grid capacity in areas where generation is limited. In this way, it provides benefits similar to offshore wind but with a more consistent and reliable output. The pathway also aligns with Norway's ongoing CO_2 infrastructure development efforts in the North Sea.

However, current capture technologies still result in residual emissions, alongside emissions generated throughout the transport and storage infrastructure. As such, the direct emission reduction potential for gas-fired power with CCS remains lower than that of other electrification options. Furthermore, the energy needed to operate capture technology, often referred to as the "parasitic load," can increase gas consumption required to power capture and compression processes. Although some of this increase may be offset by replacing older, less efficient turbines, the overall emissions reduction potential of CCS is ultimately dependent on the emissions associated with the fuel gas supply, capture process, and the logistics of CO_2 transport and storage infrastructure.

Therefore, a system relying solely on gas-fired power plants with CCS may fall short of achieving near-zero emissions unless further advancements are made in capture technology and supporting infrastructure.

5.4.1 Design considerations

Gas-fired power hubs with CCS can be implemented as either onshore or offshore units, each with distinct design considerations and operational challenges.

Onshore hubs can utilise larger, more efficient turbines and generally offer lower capital and operational costs for the power plant and carbon capture (CC) facility itself. The technology is mature, and although carbon capture has not been implemented fully on commercial gas-fired power stations, there are currently 26 projects in the pipeline[91]. Compared to offshore units, the infrastructure costs for importing natural gas and exporting and storing CO_2 could be high. Additionally, the need for extended transmission infrastructure, particularly with HVDC connections, can drive up overall costs. Due to their size, finding suitable locations onshore might be challenging, although locating them near industrial sites with established natural gas and CO_2 handling infrastructure – like Øygarden and Melkøya – could be an opportunity.

Offshore hubs, on the other hand, present novel applications of CCS technologies, with no units currently in operation. These hubs would typically involve smaller power generation units with a lower efficiency than its onshore counterpart but could be placed closer to the oil and gas assets, offering certain benefits. For one, proximity to infrastructure for importing natural gas and ideally for exporting and storing CO_2 could limit the the cost and complexity of the required infrastructure. Additionally, locating the units closer to the assets allows for lower-voltage AC cables for electricity transport, reducing the footprint of electrical infrastructure compared to HVDC transmission. The location of the power hub should balance proximity to the installations to be electrified and the CCS value chain to optimise both cost and technical feasibility.

Note, however, that offshore units would also likely require a connection to the onshore grid to optimise the power unit's design capacity, especially as the energy requirement of oil and gas production declines over time. If connected to the grid, recent studies estimate the cost of power delivered to the grid from offshore units to be around 70% higher than onshore power plants[92]. Another challenge is the relatively lower capture rates expected compared to onshore units. A recent study from SBM and Mitsubishi Heavy Industries[93] considered carbon capture for decarbonisation of an FPSO

91 According to GlobalData
92 Roussanaly, S. et al (2019) https://doi.org/10.1016/j.apenergy.2018.10.020
93 Le Touzé et al. (2024)

vessel, finding that the overall capture rate from an offshore gas turbine would be around 80%[94]. Key challenges included equipment footprint, flow assurance, and corrosion issues. Another study by SINTEF[95] found offshore power hubs with CCS to have an optimal CO_2 capture ratio of 82%, though this did not include emissions associated with transport and storage, which can be significant. For example, Sleipner and Snøhvit have vented 1.7% and 7.5%, respectively, of the total CO_2 captured during their operational lifetimes up to 2022[96], while Northern Lights reported a 97.4% net abatement of stored CO_2[97]. There are, however, a few early-stage concepts from suppliers of floating CCS power hubs with more optimistic capture, transport, and storage rates. As these units have not yet been implemented to date – although there is one project in Angola with partial capture aiming to start operation in 2025[98] - demonstration projects could offer valuable insights into these important topics.

5.4.1.1 Operational experience with high capture rates is limited

Most experience with carbon capture in Norway and globally comes from pre-combustion gas sweetening – such as Sleipner and Snøhvit – rather than post-combustion applications aimed at maximising emission reductions. While the Sleipner CCS project provides valuable lessons in storage management and offshore operations, it does not serve as a good model for projects aiming to maximise carbon capture. The project's business case is primarily driven by reducing the CO_2 content in the gas to meet pipeline specifications[99] and lowering of the carbon tax obligations, achieving a maximum capture rate of around 65% when accounting for venting. Figure 5-9 shows the reported historical data on capture, venting, and storage, with capture rates closely tied to production levels, which have declined over time[100].

While achieving consistently high capture rates is not essential for gas sweetening, it is critical for post-combustion projects focused on emissions reductions. Although several projects are in the feasibility stage to target carbon capture on gas-fired power plants, no large-scale, commercial plants are currently in operation. The most relevant demonstration to date is the Bellingham natural gas combined cycle facility in the US, where 15% of the flue gas was diverted through capture equipment using Fluor Econamine, with reported capture rates between 85-95%[101]. As performance data for Bellingham is not fully available, the operational context for these reported rates is unknown. An effective emissions reduction project on the NCS would need to achieve the upper end of capture rates on 100% of the fuel gas while also ensuring an efficient transport and storage infrastructure for the captured CO_2.

This limited operational track record in achieving stable, high capture rates highlights the need for further innovation and reliability testing to increase CCS effectiveness for post-combustion applications.

[94] The study assumed an equipment capture rate of 90% but only on 90% of the flue gas, although there is no technical barrier to apply carbon capture on 100% of flue gas.

[95] Roussanaly, S. et al (2019) https://doi.org/10.1016/j.apenergy.2018.10.020

[96] https://unfccc.int/documents/627398

[97] https://norlights.com/news/northern-lights-value-chain-provides-97-net-CO2-abatement/

[98] Involving carbon capture on part of the flue gas from turbines on the FPSO Agogo. https://www.carboncircle.com/carbon-circle-as-signes-pioneering-epc-contract-for-offshore-carbon-capture

[99] The project separates CO_2 from gas in the field before export, lowering CO_2 concentration from about 9% to 3% mole, with additional blending of gas from the Troll field reducing the final concentration to the 2.5% required for export. Source: Solbraa (2010)

[100] https://unfccc.int/documents/627398

[101] See page 48 - https://epa.illinois.gov/content/dam/soi/en/web/epa/documents/public-notices/2011/christian-county-generation/project-summary.pdf

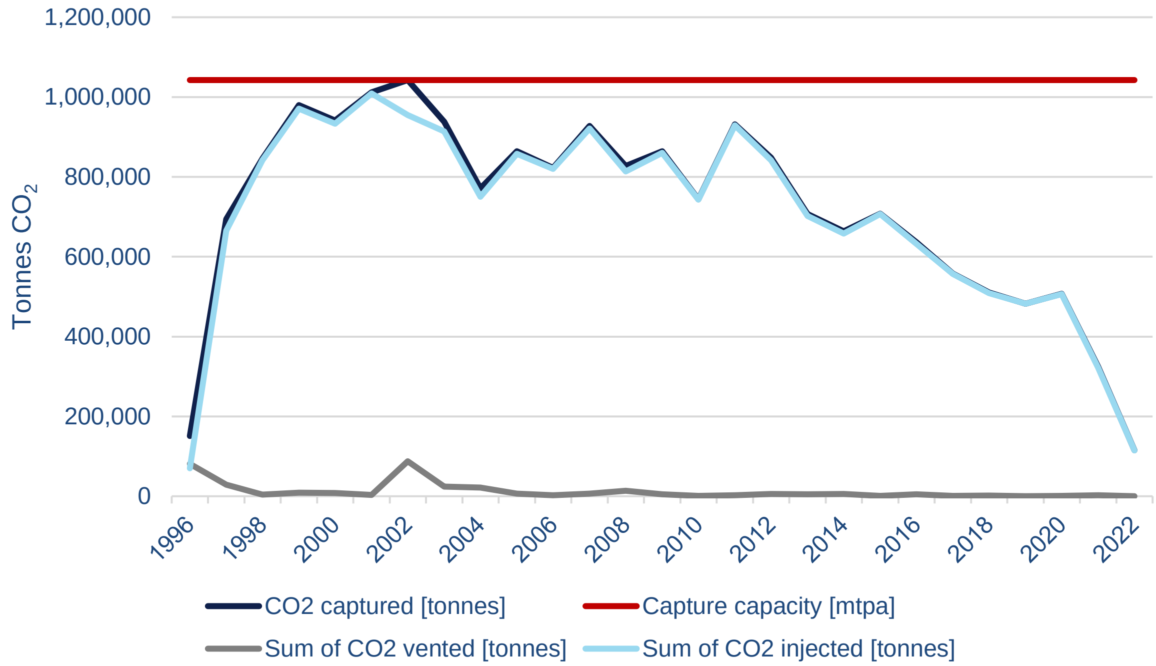

Figure 5-9: Equipment capture capacity, captured, vented, and stored CO_2 for the Sleipner CCS project

5.4.1.2 Challenges in achieving high capture rates and emission reductions

Currently, the maximum capture rate of CO_2 from turbine exhaust gas using mature technology is up to 90% under optimal conditions and minimal flaring and methane leakage, typically falling within a range of 80 – 90%[102]. Equipment suppliers often quote higher capture rates of 95%+, but these have yet to be demonstrated consistently in commercial applications.

Over the past two decades, several capture technologies have been developed for the power sector to handle relatively low CO_2 concentrations (<30 vol%), achieving high technology readiness levels (TRLs 9–11) in certain applications. However, for the use in gas-fired power plants, these technologies have a lower TRL as they still need to demonstrate consistent high capture rates in new environments and integrate effectively with both electrification and CCS infrastructure.

History shows that integrated systems have struggled to consistently meet target capture rates in full-scale power plant applications. For example, the Petra Nova project in the U.S. averaged a capture rate of 83% and only met its target rate in one out of three years of operation[103]. Similarly, the Boundary Dam project in Canada achieved average capture rates of around 50–54% over its lifetime[104]. The Bellingham gas-power with CCS pilot reported capture rates of 85–95% on 15% of the flue gas, though operational data for these rates is not available[105].

Given the maturity of commercial amine-based capture systems and their history of underperformance on power plants, it may take considerable time to reach higher TRLs for consistent 95%+ capture rates. For gas-fired power plants with CCS to compete with direct emission reductions with other electrification pathways, the capture rates need to reach this level while minimising emissions throughout transport and storage. Lower capture rates lead to residual emissions,

[102] Roussanaly, S. et al (2019) https://doi.org/10.1016/j.apenergy.2018.10.020, https://www.equinor.com/energy/carbon-capture-utilisation-and-storage#faqs
[103] https://www.osti.gov/servlets/purl/1608572. Data is not yet available for the recent re-starting of the project in 2023.
[104] https://www.saskpower.com/about-us/our-company/blog
[105] https://epa.illinois.gov/content/dam/soi/en/web/epa/documents/public-notices/2011/christian-county-generation/project-summary.pdf p48

estimated to be in the range of 8-16% before considering emissions from the supporting infrastructure[106]. These challenges underscore the need for continued innovation, reliability testing, and targeted technology development to make this pathway viable at scale.

5.4.1.3 Infrastructure needs to be developed

To fully realise the potential of any CCS-based system, a value chain for CO_2 transport and storage must be established, and the optimal location for the power-hubs will rely heavily on the availability of such infrastructure. At present, only the Northern Lights project on the NCS has reached FID, with the storage capacity for phase 1 already fully booked[107]. Additional storage projects are under development but in an early phase, including Smeaheia, Polaris, Luna, Poseidon, Havstjerne, and Trudvang. Although these are not expected to begin CO_2 injection until after 2030, they may provide potential storage solutions for power hubs in the medium to long term[108].

The Sleipner project serves as a valuable model for CO_2 injection and monitoring, having successfully injected 98.3% of the captured CO_2 and demonstrated capabilities for long-term storage and subsurface plume monitoring. Publicly shared data from Sleipner offers transferable knowledge that can benefit future offshore CCS projects – both in terms of storage and offshore capture operations[109]. Currently, the project has a TRL of 8, indicating "first-of-a-kind commercial" status. The Northern Lights project, once operational, is expected to achieve a similar TRL for the full value chain. While these examples underscore the feasibility of offshore CO_2 storage, further developments in infrastructure will be essential for scaling CCS, as current project capacities are already fully allocated.

Strategic alignment with new storage site developments will be important, as any risks to storage sites – such as unexpected pressure issues experienced at Snøhvit[110] - could impact associated carbon capture projects, leading to potential downtime and added costs. Careful planning and coordination with storage infrastructure expansion will be essential to support widespread CCS adoption and achieve meaningful CO_2 reductions.

5.4.1.4 High costs and history of cost overruns

The costs associated with gas-fired power plants using carbon capture technology remain high, influenced by CAPEX for the capture plants, variability in OPEX, and a history of budget overruns. These challenges highlight the need for further developments to increase the economic viability of CCS deployment on a large scale.

Capital costs

Carbon capture typically accounts for most of the cost of the CCS value chain for emissions sources with low CO_2 concentrations (< 30 vol%). In the US, 70-90% of the total cost of a large-scale CCS system for onshore power production, capture and storage is associated with the capture system[111]. However, this proportion will differ depending on the value chain configurations, with the transport and storage share increasing for highly complex systems or for transport over longer distances.

To estimate costs for onshore gas-fired power plants with carbon capture, we have used insights from our Capture Cost Database. This database compiles public data from operational projects, feasibility studies, and pre-FEED/FEED reports. As of 2024, the capital cost per metric tonne per annum (mtpa) of CO_2 capture capacity ranges between **450–600 million USD**, with the breakdown shown in Table 5-A. This reflects the total capital costs for the capture plant, CO_2

[106] On a high level, DNV estimates show that the maximum proportion of petroleum industry emissions that CCS-equipped gas turbines could address is currently estimated at 64–72% on NCS level. This calculation considers that gas turbines are responsible for roughly 80% of total emissions, and current capture rates expected to range from 80–90%. This leaves a residual emissions range of 8–16% that would persist if CCS is relied upon as the primary decarbonisation solution for gas turbines.

[107] https://www.equinor.com/news/20240926-northern-lights-ready-to-receive-CO2

108 https://bellona.no/publication/status-pa-CO2-lagringslisenser-i-norge

[109] https://www.sintef.no/en/projects/2017/CO2-storage-data-consortium-sharing-data-from-CO2-storage-projects/

[110] https://www.sciencedirect.com/science/article/pii/S187661021300492X

[111] US DOE 2010 Report of the Interagency Task Force on Carbon Capture and Storage, Washington, DC

compression units, facility integration, and auxiliary systems. Note that the estimate is high level and based on a limited set of reference data, and does not include operating costs, transport and storage infrastructure, or any cost increases from additional power generation equipment. A more detailed overview of the methodology for estimating and benchmarking costs can be found in Appendix D.

Table 5-A: CAPEX estimates for onshore gas-fired power plants with CCS

Gas power plant output (MWe net)	Cost range of capture plant (MNOK)	Cost range of gas-power plant (MNOK)	Total cost of gas-power plant with carbon capture (MNOK)
200	2283 to 3041	2625 to 2845	4908 to 5886
250	2742 to 3649	3281 to 3556	6023 to 7205

An important finding is that the reference cases show limited economies of scale relative to capacity, as seen in Figure 5-10. This is likely due to the low CO_2 concentrations in gas power applications which translates to modest reductions in flue-gas handling equipment for incremental CO_2 capture capacity. Moreover, there is no clear cost reduction trend, with most references from the last 16 years (except the Peterhead outliner) seeing CAPEX in the region of 500-600 million USD/mtpa.

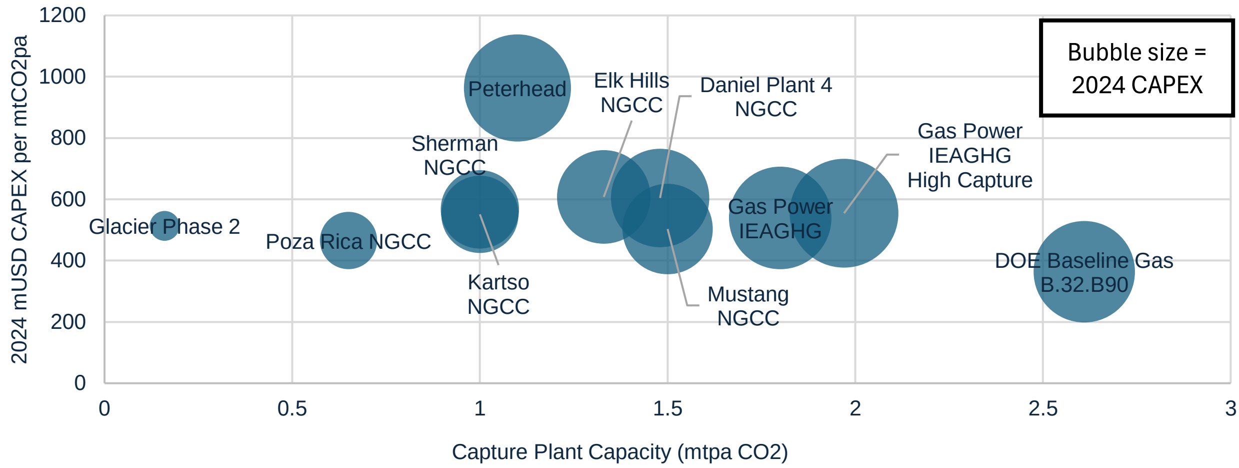

Figure 5-10: Adjusted CAPEX/tonne CO_2 vs. plant size. NGCC stands for natural gas + carbon capture power plant

Operating costs

Operating costs are influenced primarily by variable expenses such as fuel and energy, which represent 60–75% of total OPEX. Fixed costs, including labour, typically do not scale linearly with plant capacity, resulting in lower fixed costs per tonne captured for larger plants. Estimates suggest a range of **40 – 65 million USD per mtpa** of CO_2 captured, based on recent projects which better reflect energy unit costs (such as Sherman & Mustang NGCC). The full reference overview can be seen in Figure 5-11. Note that the Peterhead project is an outliner due to high unit prices for energy and utilities.

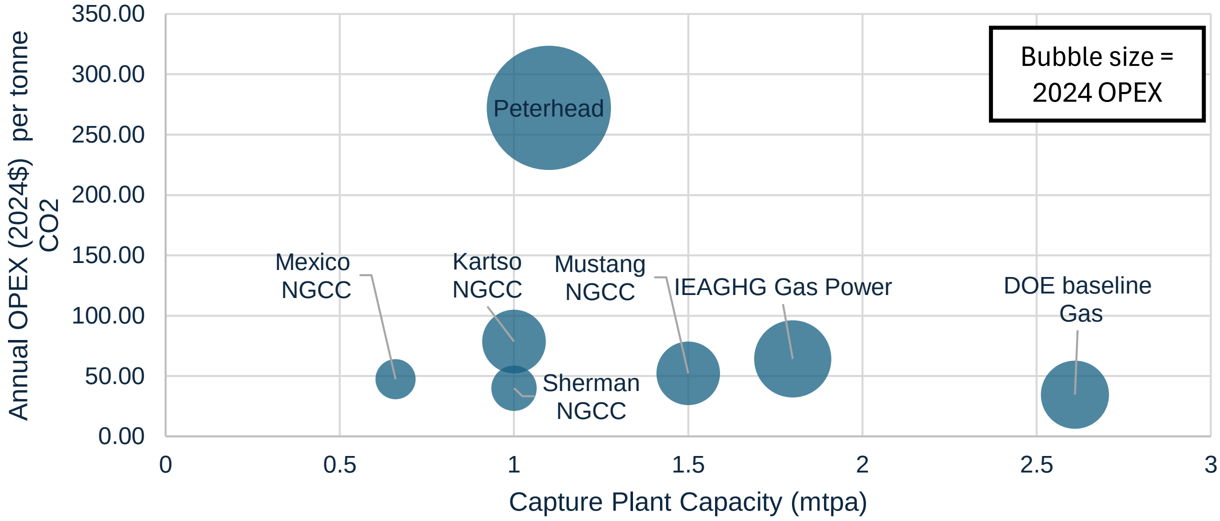

Figure 5-11: Annual OPEX per tonne CO_2 vs capture plant capacity in mtpa. NGCC stands for natural gas + carbon capture power plant

Cost overruns and project delays

Cost overruns has been a key issue for several CCS projects, including the Klemetsrud project in Oslo, which experienced significant budget increases and delays. Initially budgeted at 5.5 billion NOK, the cost rose to 9.5 billion NOK with a three-year delay, along with a reduction in the projected amount of CO_2 to be captured[112]. Similarly, the Brevik CCS project faced cost escalations[113], and the Mongstad project was ultimately cancelled in 2013 due to delays and cost overruns[114]. These challenges emphasize the financial uncertainties associated with CCS project development, requiring robust cost management and risk assessment strategies.

5.4.2 Focus areas and R&D action list for gas-fired power with CCS

The key focus areas for development in gas-fired power hubs with CCS include reducing cost and increasing capture rates. This can be done in several ways, such as innovating new technologies, optimising existing systems and processes, leveraging learnings from past projects, and implementing more commercial-scale projects. Additionally, reducing project-specific costs will depend on optimising the power plant's location relative to gas and CCS infrastructure, along with process optimisation and enhanced system integration.

To enable effective emissions reductions from gas-fired power with CCS, the Norwegian industry can play a key role through supporting targeted R&D and strategic initiatives. Below, we aim to highlight some key focus areas, each with specific actions the industry can take to drive progress.

5.4.2.1 Driving developments in emerging capture technologies

There are three main systems for carbon capture: post-combustion, pre-combustion, and oxy-fuel combustion. For power-plants with CCS, post-combustion capture will be most relevant given its maturity for power generation systems. For post-combustion capture, technologies can be categorised by way of capture media used to separate out CO_2,

112 https://www.vg.no/nyheter/i/LMjABQ/ny-enighet-vil-bruke-9-5-milliarder-paa-karbonfangst
113 https://gassnova.no/app/uploads/sites/6/2024/06/NC04-NOCE-A-RA-0014_01-Lessons-Learned-Report-2023-Public-Version.pdf
114 https://www.bloomberg.com/news/articles/2013-09-20/norway-drops-moon-landing-as-mongstad-carbon-capture-scrapped

mainly within the areas of solvent systems (absorption), sorbent systems (adsorption) and membrane technologies (permeable material). Hybrid technologies refer to multiple technologies being designed into one system to combine the advantageous attributes from each technology. More detail on emerging capture technologies can be found in Appendix E.

To improve capture rates and reduce costs for post-combustion capture technologies in low CO_2 concentration environments, focus should be given to three main areas of improvement: **materials**, **processes**, and **equipment design.** These focus areas are consistent with the R&D areas described in the recently published DOE Office of Fossil Energy and Carbon Management Strategic Vision[115].

1. **Advanced materials for capture**
   - **Goal:** Develop high-performance solvents, sorbents, and membranes that increase CO_2 separation efficiency, lower energy consumption, and improve durability. Increased efficiency and faster reactions allow for shorter resistance times and smaller reaction vessels, resulting in lower capital costs. Lower energy consumption result in lower parasitic energy losses, further decreasing costs, while improved durability mitigates loss and degradation of the capture media.
   - **Suggested R&D focus areas and ongoing initiatives**: Continue innovation, development and testing of novel materials, both for solvents, sorbents, and membranes. It is worth noting that there are technologies that are currently at a very low TRL which could be disruptive if commercialised. For more details on ongoing developments and R&D focus of the industry, see Appendix E.
2. **Process improvements**
   - **Goal:** Optimise capture processes by streamlining operations and combining process steps or equipment to enhance integration efficiency and reduce capital and operational costs.
   - **Suggested R&D focus areas and ongoing initiatives**: Focus on heat integration to reduce energy consumption in both the capture system and the associated power plant, such as boiler feedwater pre-heating. Further develop hybrid processes for process intensification – such as using both a solvent and a membrane contactor – to consolidate multiple process steps or systems into smaller, more efficient systems.
3. **Innovative equipment design**
   - **Goal:** Create compact and energy-efficient capture equipment to simplify the capture process, increasing CO_2 concentrations and reducing costs.
   - **Suggested R&D focus areas and ongoing initiatives**: Develop designs that enhances contact between the capture medium and flue gases to increase mass transfer and decrease the size of sorption equipment. Examples include rotating equipment that introduce substantial improvement in heat and mass transfer by applying high G-forces. Other focus areas include advancing manufacturing techniques that promote the construction of more efficient heat transfer surfaces to allow for greater process integration, and demonstrating and testing compact capture technologies in offshore environments. In addition, modularisation and efforts to standardise equipment enables mass production and off-site manufacturing, further reducing costs.

5.4.2.2 Enabling large-scale infrastructure for CCS

Goal: Develop accessible, scalable CO_2 transport and storage infrastructure to support large-scale CCS deployment on the NCS.

[115] DOE Office of Fossil Energy and Carbon Management Strategic Vision 2022

Selected R&D focus areas:

- Contribute to advancing developments on new license areas and Northern Lights phase 2.
- Correlate planning of the power hubs with ongoing developments to optimise infrastructure logistics and reduce costs.
- Develop and test flexible, cost-effective CO_2 transport methods for offshore and onshore hubs, such as floating hub collection systems.

Examples of ongoing initiatives:

- The STARFISH project is developing an open-access CO_2 storage concept that could benefit both onshore and offshore power hubs with CCS. The project aims to develop an offshore injection unit, designed to receive large volumes of liquid CO_2 directly from transport vessels and direct this in the nearby storage reservoir. The project recently received 225 million EUR in funding from the EU Innovation Fund[116].
- The Net Zero Industry Act in Europe is the largest driver of CCS infrastructure development in Europe, setting an annual CO_2 injection capacity target of 50 million tonnes by 2030. To meet this goal, oil and gas producers within the EU will be required to contribute to the target in proportion to their share of the region's crude oil and natural gas production. Each country should establish a "one-stop shop" to streamline and coordinate the permitting process for manufacturing projects. Clear timelines will be set, with priority given to designated "strategic" projects[117].

5.4.2.3 Scaling knowledge and best practices

Goal: Facilitate knowledge sharing between projects and develop industry-wide best practices to minimise risk of operational issues and cost overruns.

Selected R&D focus areas:

- Establish a shared knowledge base for CCS projects across the full value chain, including actual cost data, operational experiences, and performance metrics
- Promote partnerships between industry, government, and academia, such as through collaborative R&D and sharing of data.

Examples of ongoing initiatives:

- Operational data being available from the Sleipner CCS project helps to facilitate knowledge sharing
- Norway is leading in initiatives on CCS infrastructure through Longship, Gassnova, and research centres such as the Norwegian CCS Research Centre (NCCS).

[116] https://alterainfra.com/articles/ccs-project-starfish-awarded-eur-225-million-from-eu-innovation-fund
[117] https://single-market-economy.ec.europa.eu/industry/sustainability/net-zero-industry-act_en

5.5 Zero-emission rigs: Reducing emissions from drilling activities

Achieving near-zero scope 1 emissions on the NCS requires a focused reduction in emissions from drilling rigs. In 2022, drilling rigs contracted by the operators contributed around 5.6% of total industry emissions[118], primarily from running multiple diesel engines and using dynamic positioning for semi-submersible rigs[119]. Station-keeping through thrusters, drilling operations, and hotel utilities consume on average 8-9 tonnes, 3 tonnes, and 23 tonnes of fuel per day, respectively, for dynamically positioned units.

As exploration and new field development expands under NOD's high production scenario, particularly in challenging Barents Sea conditions, drilling rigs are likely to account for an increasing share of total emissions. The Barents region's harsh weather, low temperatures, and demanding metocean conditions, combined with historically lower exploration success as seen in Figure 5-12, underscore the importance of advancing low-emission drilling solutions to meet the industry targets.

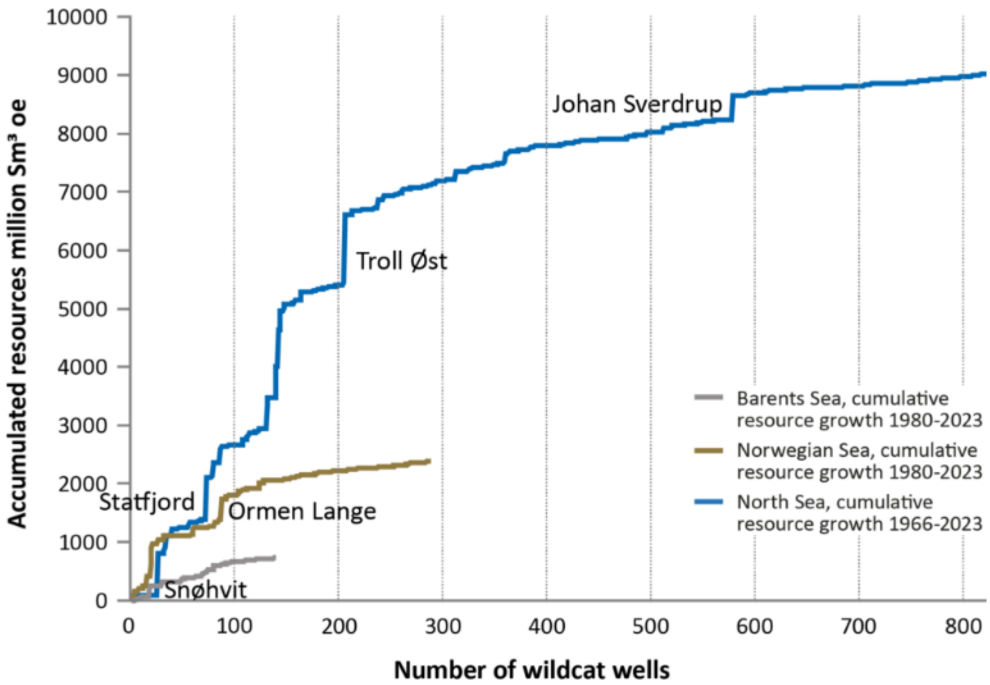

Figure 5-12: Cumulative resource growth per sea area by number of wildcat wells (NOD 2024)

The characteristics of Norway's drilling fleet present a unique opportunity to drive zero-emission technology adoption. The fleet is relatively small and operates under stable, long-term contracts within defined geographical areas, allowing for the efficient introduction of new legal, infrastructural, logistical, and technical solutions. However, to justify investments in net-zero emission rigs and move the solutions from concept stage to full-scale application, long-term contracts (ideally five years or more) with favourable day rates are essential for a viable business case, even when supported by government financing schemes.

As such, operators play a pivotal role in emission reductions from drilling by setting clear decarbonisation requirements in tender specifications. For example, Equinor has historically incorporated specific propulsion and environmental requirements into its fleet charters, enabling advances in both vessel propulsion technologies and the development of

118 13931: Klimagasser AR5, etter kilde (aktivitet), komponent, statistikkvariabel, år og energiprodukt
119 Note that emissions from the rig when travelling between locations does not fall under the petroleum industry totals and so are not included here

harsh-environment rigs tailored to Arctic operations[120]. A coordinated push from government and pull from major operators will be important to enable investment in zero-emission drilling technologies.

5.5.1 Available technologies for zero emission drilling units

Achieving net-zero drilling operations relies on two core strategies: improving operational efficiencies and integrating new technologies and value chains. Emissions reductions typically follow a merit order of operational improvements, progressing from efficiency measures to hybrid solutions, and ultimately to alternative fuels or other low- to zero-emission solutions.

5.5.1.1 Efficiency improvements, hybridisation and closed bus systems are low-hanging fruits

Optimising the number of engines on a rig can significantly cut fuel consumption, leading to notable emission reductions. Most rigs operate six to eight diesel engines at around 30% capacity. By implementing operational efficiency measures, installing batteries, and adopting closed bus systems to manage power distribution, fuel consumption can be reduced from an initial 50 m^3 per day down to approximately 30 m^3 per day. Incorporating batteries and flywheels can further improve fuel efficiency by enabling peak shaving and energy storage during downtime, indirectly benefiting the wider supply chain through reduced fuel transportation needs.

Industry-funded initiatives, such as those by the NOx fund, have facilitated direct fuel consumption reductions. For instance, Transocean received funding for efficiency measures which resulted in significant reductions in fuel use[121], and Odfjell Drilling have achieved substantial reductions by implementing power-saving measures, with Odfjell's Deepsea Nordkapp reducing NOx emissions in the range of 70-90%[122].

Recent contract structures between operators and drilling contractors now include fuel efficiency incentives, fostering a joint commitment to reducing fuel use on drilling rigs.

5.5.1.2 Transitioning to low-carbon fuels can enable zero-emission operations

The shift toward alternative fuels, including dual-fuel engines using diesel and methanol or diesel and ammonia, offers considerable emissions reduction potential. A key challenge is the lower energy densities of the fuel, which requires larger storage tanks. However, incorporating energy efficiency measures reducing the number of engines required can free up space to make room for additional fuel storage.

According to drilling companies, retrofitting engines to handle alternative fuels could be feasible within a 5–10-year timeline, while a complete transition to alternative power sources is anticipated in a 15-20-year horizon. The feasibility of running the rigs on alternative fuels is dependent on fuel availability and proximity to supply infrastructure, which could be a challenge in more remote regions. Biofuels, such as hydrogenated vegetable oil (HVO), have shown promise, with Odfjell Drilling recently achieving an 80% emissions reduction on its Deepsea Atlantic unit using HVO. This option would not require major retrofits to the existing fleet, and Odfjell Drilling have concluded that their mobile offshore drilling units (MODU) are ready to operate on HVO. However, cost and availability of biofuel remain significant barriers to large-scale adoption. For this reason, many drilling companies see ammonia as a more flexible alternative, although diesel will still be required as backup and to support certain operations.

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[120] Songa providing Statoil with a new rig type - equinor.com
[121] https://www.noxfondet.no/en/news/energy-efficiency-measures-on-transocean-rigs/
[122] https://www.noxfondet.no/nyheter/deepsea-nordkapp-med-nye-tiltak-som-reduserer-320-tonn-nox/

5.5.1.3 Electrification remains challenging

Electrification via floating cables remains a limited option, especially for temporary drilling operations of only a few months. Feasibility would also depend on proximity to an electrified platform with sufficient capacity to support high-power drilling operations, which could be a challenge.

5.5.2 Main technical and commercial challenges

Deploying zero-emission technologies for drilling rigs presents several technical and commercial challenges, as outlined below.

5.5.2.1 Access to alternative fuels and supporting infrastructure

Access to low-carbon fuels, such as biofuels, ammonia, or methanol, is currently limited, with recent cancellations of low-emission fuel projects in Northern Norway increasing the risk. However, although still in the early stages of development, there are still several ammonia projects in the pipeline in Norway. If realised, the total production capacity could be up to 2.1 million tonnes per year[123].

Developments in EU regulation, such as the Renewable Energy Directive (RED) [124], are expected to increase both supply and demand for alternative fuels. While this could help boost availability, it could also lead to higher prices and tighter supply of limited resources like biobased feedstock. In the longer term, major exporters of biofuels and biobased feedstocks could become importers as their domestic targets for biofuels grow. For instance, China – currently the largest exporter of used cooking oil, a key feedstock for certain biofuels – may begin prioritising domestic biofuel demand, which could place additional strain on EU imports and tighten global supply chains[125].

A further logistical challenge for alternative fuels is the limited storage space available on rigs, which could require a more optimised and efficient supply chain of fuels to meet offshore needs. Costs related to sourcing, transporting, and storing alternative fuels are expected to be high, especially for more remote areas. The average fuel demand of the total Norwegian fleet is between 8,000 to 12,000 tonnes per year[126], equating around 184,000 to 276,000 tonnes of biofuel[127] or 373,000 to 559,000 tonnes of ammonia.

With biofuels and clean ammonia priced significantly higher than traditional fossil fuels on an energy-equivalent basis, as seen in Figure 5-13[128], the total annual fuel costs could escalate substantially. For example, at today's prices of 2700 USD/tonne equivalent for green ammonia, total annual fuel costs would be in the range of 4.9 to 7.5 billion NOK. However, this price would likely come down as technology develops and global supply increases. Additional costs for specialised carriers and base facilities also add to both CAPEX and OPEX. Transitioning carrier ships to alternative fuels could streamline infrastructure needs, ultimately benefiting both rig and vessel operations.

[123] https://afi.dnv.com/
[124] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A02018L2001-20240716
[125] https://www.transportenvironment.org/uploads/files/TE_UCO-Study_Stratas_11062024.pdf
[126] Assuming there are 23 rigs currently operating in Norway, according to Clarkson's World Offshore Register. Source: https://www.clarksons.net/wor/
[127] Assuming the same energy density as fossil diesel/MGO
[128] https://afi.dnv.com/statistics/2ae7811e-af73-4b93-bc9a-19c440816b2a

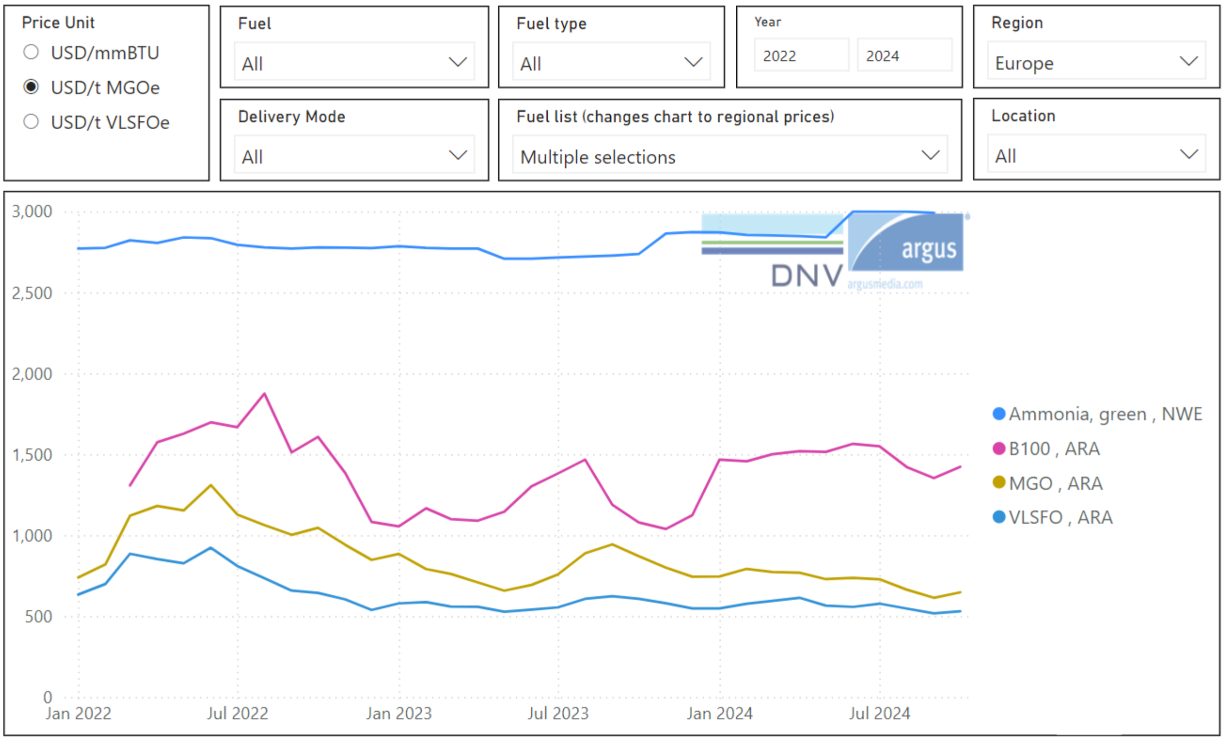

Figure 5-13: DNV's Alternative Fuels Insights Prices Dashboard showing recent prices for fossil and alternative fuels

5.5.2.2 Retrofitting the existing fleet is costly, but a more likely pathway than newbuilds

Before the oil market downturn in 2015, there was a boom in newbuild of rigs. Given that a lot of these rigs were designed for lifetimes of 40+ years, they are expected to operate well into the 2040s. Moreover, as activities have not picked up to pre-downturn levels, the market is saturated, with numerous stranded or even scrapped rigs. As banks and investors were over-exposed before the downturn, leading to significant losses and several financiers pulling out of oil and gas operations permanently, access to financing for new rigs remains challenging.

In addition, building new zero-emission rigs will require significant capital. Newbuild semi-sub rigs for harsh environments have seen average cost levels of 500 – 750 million USD over the past 5 years, according to Clarkson's World Offshore Register[129]. Due to more novel technologies, zero-emission newbuilds are likely more costly, with a high-level indication of 1 billion USD per rig, according to Odfjell Drilling. This translates to a total cost of around 23 billion USD for replacing the Norwegian fleet[130].

Combining high capital cost with limited access to financing, prolonged construction periods, and current long-term day rates not justifying investments, retrofits and alternative fuel integration are more likely pathways to achieving zero emission drilling operations than new builds.

However, adapting current rigs to run on alternative fuels (besides biofuels) poses complex technical challenges such as modifying the bunkering systems, expanding storage for alternative fuels, and reconfiguring engines. This requires substantial capital, although far lower than newbuilds. Conversations with drilling companies indicate capital costs in the range of 400 million NOK (around 36 million USD) for retrofitting a drilling rig to ammonia dual-fuel operations, totalling 9.2 billion NOK (800 million USD) for the total fleet. This includes converting existing engines and installing an ammonia

[129] https://www.clarksons.net/wor/

[130] Assuming there are 23 rigs currently operating in Norway, according to Clarkson's World Offshore Register. Source: https://www.clarksons.net/wor/

storage and transfer system onboard. However, significant cost reduction potential has been identified pending future developments in technology maturity and regulatory frameworks.

5.5.2.3 Harsh environmental conditions increases complexity

Operating in extreme weather, ice, and isolated regions significantly complicates logistics and limits the range of feasible technologies. These factors add complexity to maintenance, fuel transportation, and equipment durability.

5.5.3 Focus areas and R&D action list for zero emission drilling units

Transitioning to zero-emission drilling units will require a combination of improved operational efficiencies, new technology integration, and sufficient availability of alternative fuels. This chapter outlines the primary focus areas for achieving these goals, providing suggestions to R&D actions and examples of ongoing initiatives. Each focus area is designed to address the key technical and logistical barriers outlined above to move toward a long-term vision of zero-emission drilling operations on the NCS.

In addition to the technical advancements highlighted below, a **key success factor** to enable investments will be a **coordinated push from government**, through available funding, **and pull from operators** through long-term contracts at favourable day rates.

5.5.3.1 Engine optimisation and fuel testing

Goal: Increase fuel flexibility and optimise engines to maximise efficiency with alternative, low-carbon fuels.

Suggested R&D focus areas:

- Develop and test dual-fuel systems, focusing on increasing the blending rate of alternative fuels
- Improve load management capabilities with battery integration to support stable operations during peak demands.
- Address safety concerns of alternative fuels.

Examples of ongoing initiatives:

- Companies like Odfjell Drilling, Transocean, and STENA have explored dual-fuel options, focusing on ammonia blending.
- The Demo 2000 research project at Stord, led by Wärtsilä, is trialling ammonia-based dual-fuel engines. The engine is a smaller version of the same engines installed on Odfjell Drilling rigs, with initial tests showing 90%+ ammonia use is feasible, though a pilot fuel is still required for ignition. The test also includes closed engine room designs and other initiatives that minimise the risks of ammonia exposure[131]

5.5.3.2 Exploring alternatives to low-carbon fuels

Goal: Explore other alternatives to running the rigs on low-carbon fuels, including electrification or carbon capture options.

Suggested R&D focus areas:

- Investigate feasibility of renewable power sources for rigs, focusing on scalability to match rigs' power needs.

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[131] https://www.wartsila.com/nor/media/nyhet/30-06-2020-verdens-f%C3%B8rste-fullskala-test-av-ammoniakkmotor-et-viktig-skritt-mot-karbonfri-skipsfart

- Further advance floating cable technology and other energy transfer solutions for short-term drilling operations.
- Pilot scalable carbon capture technologies adapted for offshore rigs, including modular systems that can be deployed in confined spaces.
- Improve CO_2 capture efficiency at small scales.

Examples of ongoing initiatives:

- A 2021 RAM study led by Odfjell Drilling assessed using offshore wind power for drilling operations. Findings indicated that the scale mismatch between turbine output and rig requirements posed a significant challenge.
- An early-stage Climit proposal in 2019/20 investigated CCS options for rigs, but the study concluded that the technology was not yet sufficiently mature.

5.6 Additional technology pathways for emission reduction

A variety of technologies can be implemented to reduce emissions from oil and gas operations, with no one size fits all. An important part of this study has been to assess a broad range of options to determine which technologies should be prioritised for deeper analysis. In collaboration with OG21, we selected the four technologies outlined above based on their high potential to achieve the near-zero emissions target and their maturity, which enables immediate action.

The decision not to prioritise certain technologies was guided by factors such as technological maturity, feasibility of implementation, and anticipated impact on emissions reduction. However, their exclusion from prioritisation does not reduce their relevance; many of these technologies will be essential towards the near-zero target and may provide the final push necessary to achieve it.

For example, technologies that enhance energy efficiency, such as improved water management, can significantly contribute to emission reductions in both the short and longer term. These technologies complement electrification efforts by reducing energy import needs. Additionally, effective energy management and measures to streamline operations, such as better reservoir management, can save time and energy, further supporting emission reduction initiatives while improving corporate value through cost savings. Certain technologies, such as the electrification of blow-out preventers and Christmas trees, will rely on the successful implementation of electrification measures.

While some options may currently face challenges related to maturity or feasibility, they warrant continued research and innovation for their potential impact in the future. For a complete overview of the evaluation process and criteria, along with a summary of non-prioritised technologies, please refer to Appendix B and C.

6 A CASE STUDY ON ELECTRIFICATION

This case study explores four different measures to electrify offshore oil and gas assets on the NCS. These measures are evaluated against the base case of "doing nothing," where platforms continue operations using conventional gas-fired turbines. The four electrification options include:

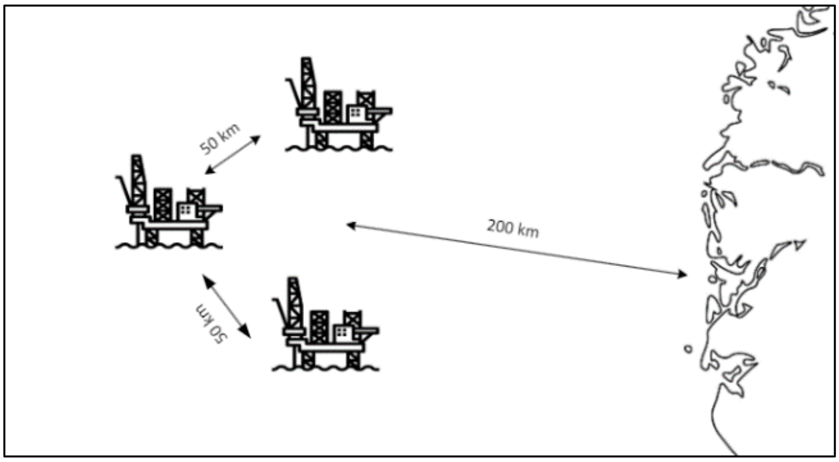
1. **Power-from-shore:** 200 km HVDC cable from shore with dedicated platform (jacket) for DC equipment with a power rating of 250 MW
2. **Power-from-shore + floating wind:** Same as case 1, including floating wind turbines with an installed capacity of 85 MW (similar to penetration level of Hywind Tampen) and capacity factor of 46%
3. **Offshore gas-fired power hub with CCS:** Sevan-cylinder floater with a gas-fired power station with CCS, power rating of 250 MW. The unit operates as a stand-alone solution and is located close to the platforms. The CO_2 is assumed to be transported and stored offshore through the Northern Lights value chain.
4. **Onshore gas-fired power plant with CCS:** Similar power-from-shore concept as Case 1. The power is supplied from an onshore gas-fired power station with CCS, power rating of 250 MW. The CO_2 is assumed to be transported and stored offshore through the Northern Lights value chain.

Each case is analysed on a NPV basis, comparing the economic viability of the various measures both for an early implementation (2024) and a late implementation (2040), with several key insights:

- Power-from-shore (Case 1) is the most favourable option, providing significant NPV improvements compared to doing nothing, especially with early implementation. Waiting until 2040 reduces the economic advantage but still yields positive results.
- Combining power-from-shore with floating offshore wind (Case 2) offers cost saving potential, although the overall potential is reduced compared with Case 1 due to the increased CAPEX. Early implementation provides the highest benefit also here.
- Gas-fired power hubs with CCS (Cases 3 and 4) are financially the least attractive options due to their high CAPEX and OPEX, irrespective of implementation time frame. These solutions remain economically uncompetitive compared to electrification and doing nothing.
- The sensitivity analysis shows that the power-from-shore solution remains the most economically favourable option within the uncertainty range, except in the case where retrofitting costs are significantly increased, underscoring the risk associated with electrifying existing assets. For the other cases, the key sensitivities include a rise in equipment cost and reduction in CO_2 taxes.

These insights highlight the importance of early action on electrification measures, strong carbon pricing policies, and managing cost and supply chain risks to ensure successful emission reduction in the oil and gas sector.

6.1 Assumptions and methodology



The case study involves a full electrification of three existing installations on the NCS, as shown in the illustration to the left. The platforms are located 200 km from shore and 50 km from each other, and each platform is run using conventional gas turbines with a peak load of 85 MW and a capacity factor of 50%.

Each case runs until 2050 and is analysed from two different timeframes: one where the platforms are fully electrified by 2026, and one where the platforms are not electrified until 2040. Where the solution is implemented in 2040, it is assumed that the current situation ("doing nothing") applies until the electrification measure is operational and that the investment has a remaining value of 35% in 2050.

The general assumptions are summarised in Table 6-A. Note that the following have not been considered: the petroleum taxation system, onshore grid investments, loss of revenue due to downtime, grid tariffs and taxes, and power losses. All costs are given in 2024 NOK.

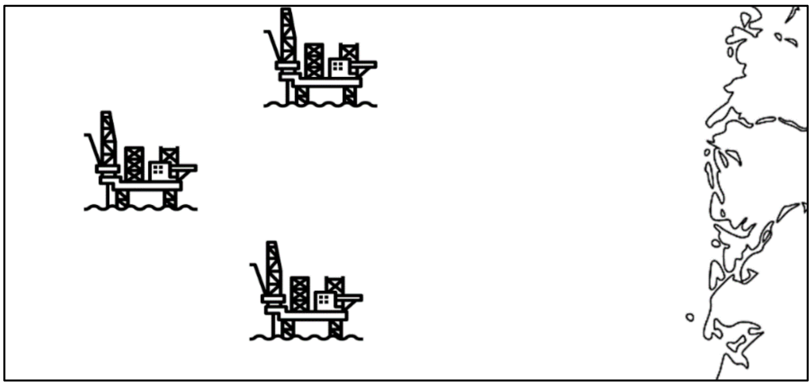
Table 6-A: General assumptions for the case study

Parameter	Assumptions 2024 | 2040	Comment
Discount rate (WACC)	8.5%	Real
Electricity price	530 | 400 NOK/MWh	Estimates for NO2/NO3 from Statnett's Langsiktig markedsanalyse[132]. Converted from EUR to NOK (1:10). Excluding tariffs and taxes.
Carbon tax	Yearly based on DNV ETO 2023	Additional Norwegian carbon taxes are not included
Natural gas price	3.5 NOK/Sm^3	
Exchange rate	10 NOK/EUR	
Platform retrofits	2000 MNOK	Estimated costs based on industry data, indicating a range of 1000 to 5000+ MNOK. Note that the costs are highly case dependent.
CO_2 emissions from gas turbines	2.2 kg/Sm^3	
Natural gas energy content	90 Sm^3/MWh	

132 langsiktig-markedsanalyse-2022-2050.pdf

6.2 Case descriptions

6.2.1 Case 0: Do nothing



In this scenario, the platforms continue operating using conventional gas-fired turbines, which leads to significant CO_2 emissions. No modifications are required.

The main assumptions are summarised in Table 6-B

Table 6-B: Assumptions for the NPV calculations of case 0: Do nothing.

Parmeter	Value	Unit
Gas turbine efficiency	30%	%
Natural gas consumption	3.65 (0.33)	TWh/year (billion Sm3/year)
CO_2 emitted	722,700	Tonne CO_2/year
CO_2 abated	0	Tonne CO_2/year
OPEX: O&M	83.33	MNOK
OPEX: Fuel cost	1150	MNOK/year

6.2.2 Case 1: Coordinated power-from-shore

This case involves the installation of a 200 km HVDC cable from shore to an offshore HVDC platform, including three 66 kV AC cables from the HVDC platform to each individual platform, as depicted in the illustration below. The main assumptions are shown in Table 6-C, with the CAPEX shown in Figure 6-1.

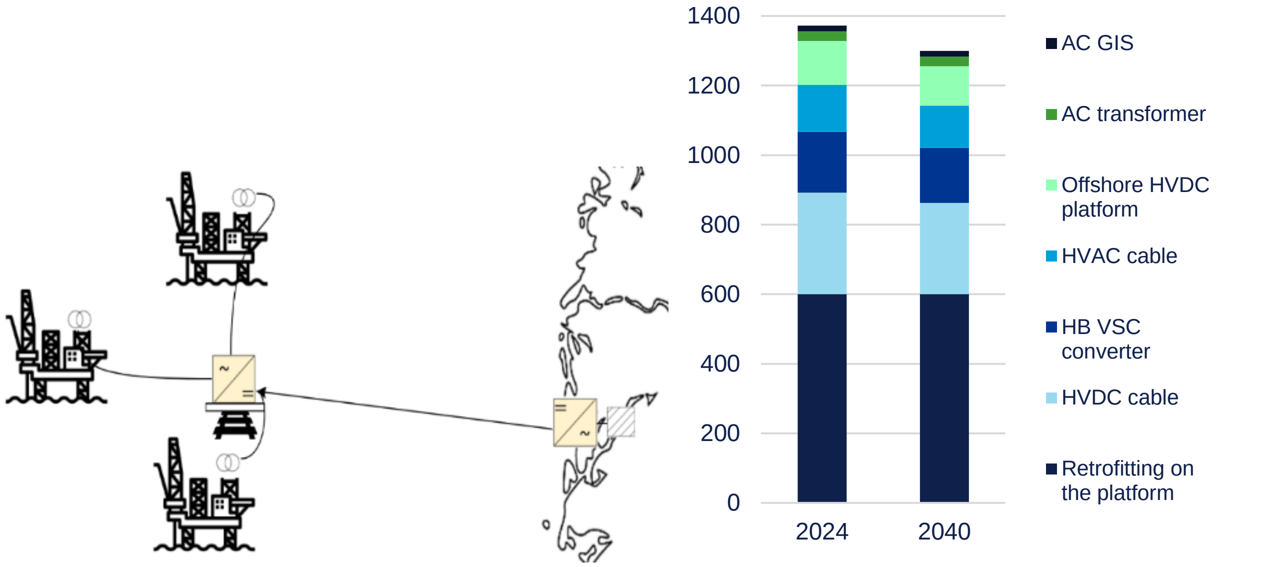


Figure 6-1: Overview of case concept and CAPEX breakdown (in MEUR) of different components for the power-from-shore case

Table 6-C: Assumptions for NPV calculations for case 1: coordinated power-from-shore electrification

Parameter	Value 2024 | 2040	Unit
Total power rating HVDC	250	MW
Electricity consumption from shore	1.095	TWh/year
CO_2 emitted	0	Tonne CO_2/year
CO_2 abated	722,707	Tonne CO_2/year
OPEX: operations and maintenance (O&M)	75.81 | 68.29	MNOK/year
OPEX: Electricity cost	580 | 438	MNOK/year

6.2.3 Case 2: Power-from-shore + floating wind

Similar to Case 1, this option includes the addition of floating wind turbines (FWT) with a capacity of 85 MW, reducing dependence on shore-based electricity. This combination is expected to further reduce cost of electricity but comes with higher CAPEX. The CAPEX breakdown for 2024 and 2040 is shown in Figure 6-2, and the assumptions are presented in Table 6-D.

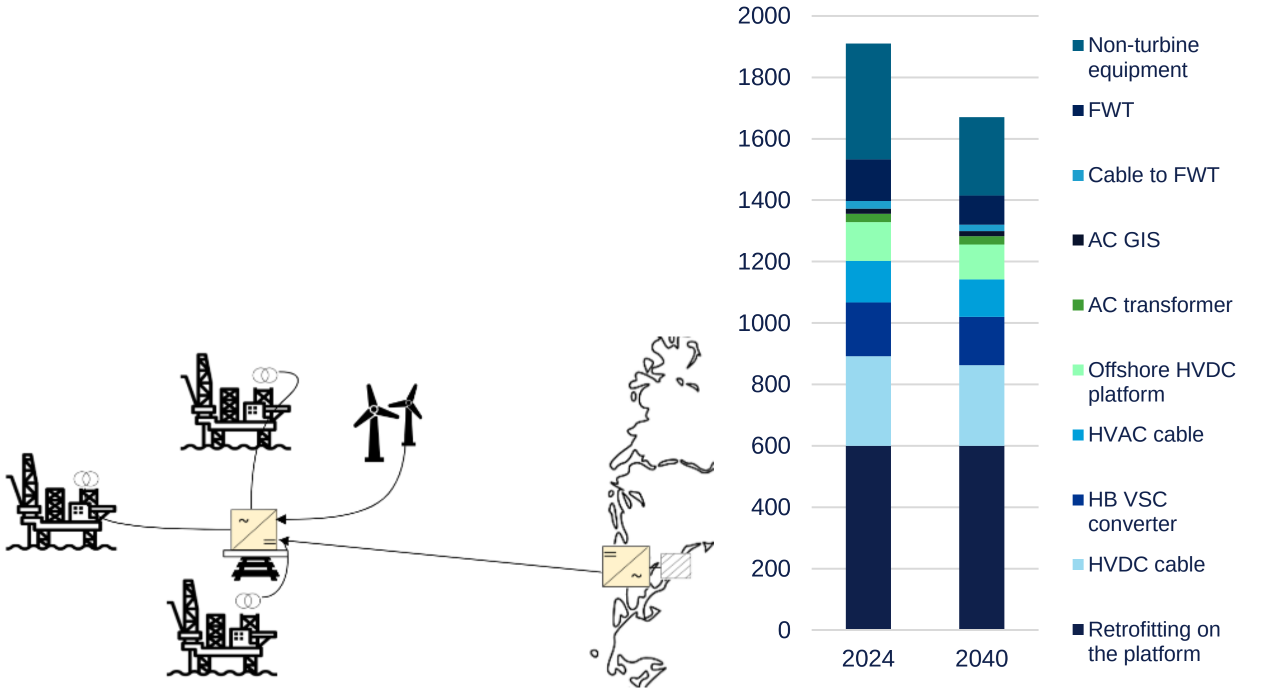


Figure 6-2 Overview of case concept and CAPEX breakdown (in MEUR) of different components for the power-from-shore + wind turbine

Table 6-D: Assumptions for NPV calculations for wind turbine + power-from-shore electrification. The cost assumptions are based on DNV's ETO 2024.

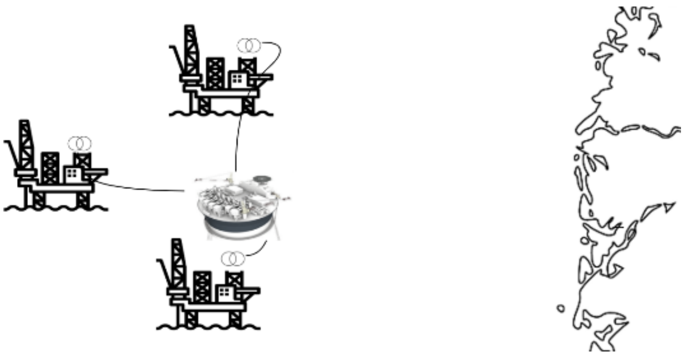
Parameter	Value 2024 | 2040	Unit
Total power rating HVDC	250	MW
Total power rating FWT	85	MW
Capacity factor FTW	46% | 47%	%
Electricity consumption from shore	0.75	TWh/year
Electricity produced offshore	0.34	TWh/year
CO_2 emitted	0	Tonne CO_2/year
CO_2 abated	722,707	Tonne CO_2/year
OPEX: O&M	185 | 143.48	MNOK/year
OPEX: Electricity cost	398.8 | 441.5	MNOK/year

6.2.4 Case 3: Offshore gas-fired power hub with CCS

In this case, a gas-fired power hub with a carbon capture unit in installed on a Sevan floater, supplying the platforms with AC-power similar through three 66 kV cables as illustrated below. The CAPEX numbers are shown in Figure 6-3[133]

The CAPEX for the gas-fired power plant is based on data from existing onshore projects and the capture equipment is based on Florez et al (2022) scaled to the right size[134]. The cost data for the floater and moorings draws from both an operator FEED study and a supplier concept estimate. Notably, the estimated costs for Sevan floaters and additional moorings vary significantly between these sources. To establish a balanced and reliable indicative cost, we consulted DNV's internal experts and arrived at a mid-point estimate of 1000 MEUR for the floater and moorings. However, it is important to note that, despite floaters being mature and widely used structures, they have not been specifically designed or tested with carbon capture equipment.

The OPEX for offshore carbon ship-transport and storage is based on estimates from the Longship project[135], adjusted to 2024-numbers. Table 6-E shows the case assumptions.



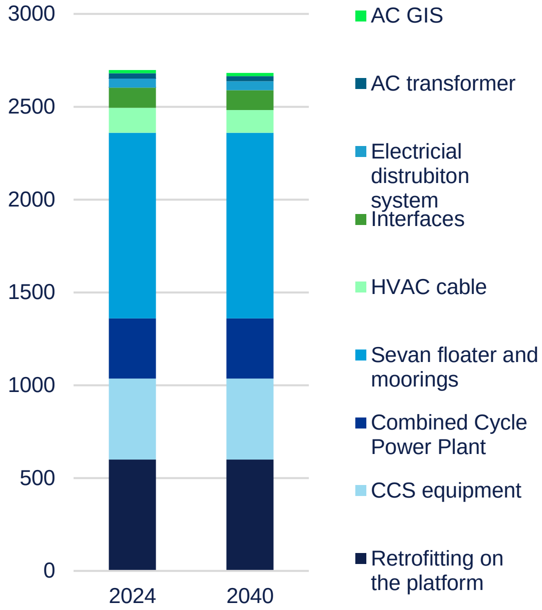


Figure 6-3: Overview of case concept and CAPEX breakdown (in MEUR) of different components for the offshore gas-fired power hub with CCS.

Table 6-E: Assumptions for NPV calculations for offshore gas-fired power hub with CCS.

Parameter	Value 2024 | 2040	Unit
Total power rating power plant	250	MW
Gas turbine efficiency power plant	55%	%
CO_2 capture rate	90%	%
Natural gas consumption	1.99 (0.18)	TWh/year (billion Sm3/year)

134 https://doi.org/10.1016/j.enconman.2021.115110
135 Report-Cost-reduction-curves-for-CCS-Gassnova-version-2b-1.pdf (ccsnorway.com)

CO_2 emitted	39,420	Tonne CO_2/year
CO_2 stored	357,784	Tonne CO_2/year
CO_2 abated	683,286	Tonne CO_2/year
OPEX: O&M	336 | 334	MNOK/year
OPEX: Fuel cost	627	MNOK/year
OPEX: CO_2 storage	1408	NOK/tonne CO_2

6.2.5 Case 4: Onshore gas-fired power plant with CCS

In this case, a gas-fired power plant with CCS is installed onshore with the same power-from-shore setup as for Case 1, as illustrated below. The total CAPEX for 2024 and 2040 are shown in Figure 6-4, and the main assumptions are highlighted in Table 6-F

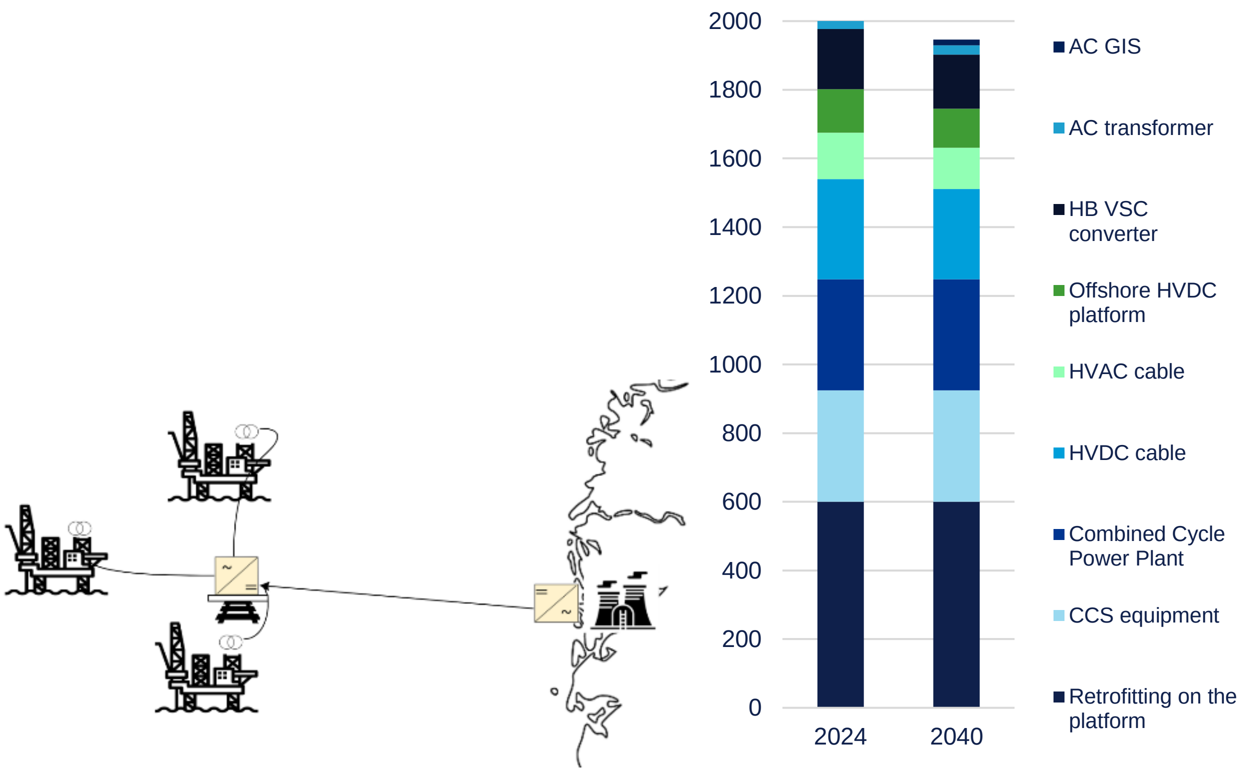


Figure 6-4: Overview of case concept and CAPEX breakdown (in MEUR) of different components for the onshore gas-fired power hub with CCS.

Table 6-F: Main assumptions for NPV calculations for onshore gas-fired power hub with CCS

Parameter	Value 2024 | 2040	Unit
Total power rating power plant	250	MW

Gas turbine efficiency power plant	55%	%
CO_2 Capture rate	90%	%
Natural gas consumption	1.99 (0.18)	TWh/year (billion Sm3/year)
CO_2 emitted	39,420	Tonne CO_2/year
CO_2 stored	357,784	Tonne CO_2/year
CO_2 abated	683,286	Tonne CO_2/year
OPEX: O&M	285 | 277	MNOK/year
OPEX: Fuel cost	627	MNOK/year
OPEX: CO_2 storage	1408	NOK/tonne CO_2

6.3 Results

The results of our NPV calculations are summarised in Figure 6-5. As no revenue is considered in our analysis, the NPVs are all negative, meaning that the lowest NPV (least negative) shows the most favourable option. Overall, the following key conclusions can be drawn from the results:

- **Case 1 (Power-from-shore):** This option presents the most economically favourable, with early implementation (2024) resulting in a 23% improvement over doing nothing (Case 0). This is largely driven by avoided CO_2 taxes and reduced fuel consumption. Waiting until 2040 (late implementation) reduces the benefits but still yields a slight improvement of 4%.
- **Case 2 (Power-from-shore with floating offshore wind):** While this option also demonstrates cost savings compared to doing nothing, its savings becomes marginal with late implementation due to the added cost of CO_2 tax and fuel consumption. The benefits are reduced compared to Case 1 due to the relatively higher CAPEX associated with floating offshore wind.
- **Cases 3 and 4 (Gas-fired power hubs with CCS):** Both onshore and offshore gas-fired power hubs with CCS are the least favourable options from a financial standpoint. Despite the potential for CO_2 abatement, the high CAPEX and OPEX associated with these solutions result in more negative NPVs than doing nothing, particularly in the 2024 scenario. Delaying installation to 2040 reduces CAPEX through discounting but remains economically inferior. The stand-alone offshore gas-fired power hub is more expensive than the onshore power plant with HVDC power transmission, largely due to the high costs related to the floater and mooring system.
- A **late implementation** is more expensive for Case 1 and 2 due to the OPEX of purchasing fuel and paying CO_2 tax during operation before the assets are electrified is more expensive than purchasing power-from-shore. This is true even though the discounting of CAPEX in the future results in a lot less CAPEX for the 2040 timeframe.

When analysing the results, it is important to remember that they are high-level and indicative only, with several key cost elements excluded. These include the petroleum taxation system, onshore grid investments, loss of revenue due to downtime, grid tariffs and taxes, and power losses. Including these cost elements could change the overall picture.

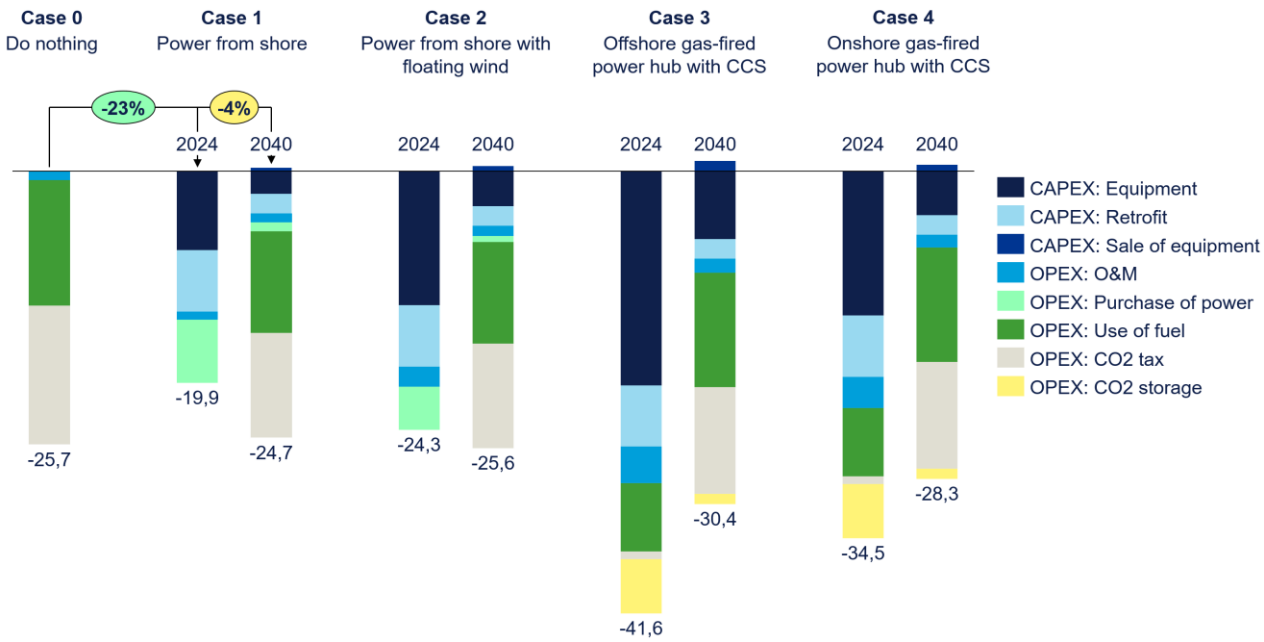


Figure 6-5: NPV results [in 1000 MNOK] from the case study for both 2024 (fully electrified in 2026) and 2040 (fully electrified in 2041).

6.4 Sensitivity analysis

Given the inherent uncertainties in the cost estimates and key assumptions, especially for a time horizon extending to 2050, we include a sensitivity analysis on critical parameters for all cases. Our analysis focuses on how variations in CAPEX, CO_2 taxes, and operational parameters impact the NPV, with the results shown in Figure 6-6 and Figure 6-7. Note that we have only applied the sensitivity for the early implementation scenario (2024).

The results show that:

- Case 1 (power-from-shore) consistently emerges as the most economically viable solution, except in a scenario where the CAPEX of retrofitting increases by 3000 MNOK, bringing total retrofitting costs to 5000 MNOK. In such cases, doing nothing becomes the most favourable option. This highlights the significant risk related to retrofitting costs, particularly for older installations where cost overruns could undermine the economic feasibility of electrification.

- A combination of power-from-shore and offshore wind (Case 2) becomes less favourable also with extreme CAPEX increases (+50%) or a substantial reduction in CO_2 taxes. An increase in CAPEX could be plausible if the current supply chain disruptions persist or worsen, although an extreme increase of +50% for all components is unlikely. The impact of lowering the CO_2 taxes on the business case underscoring the importance of ensuring carbon prices remain high.

- Both onshore and offshore gas-fired power hubs with CCS (Cases 3 and 4) remain more expensive than doing nothing, irrespective of CAPEX and operational variations. These results highlight the complexity and cost-intensiveness of CCS projects.

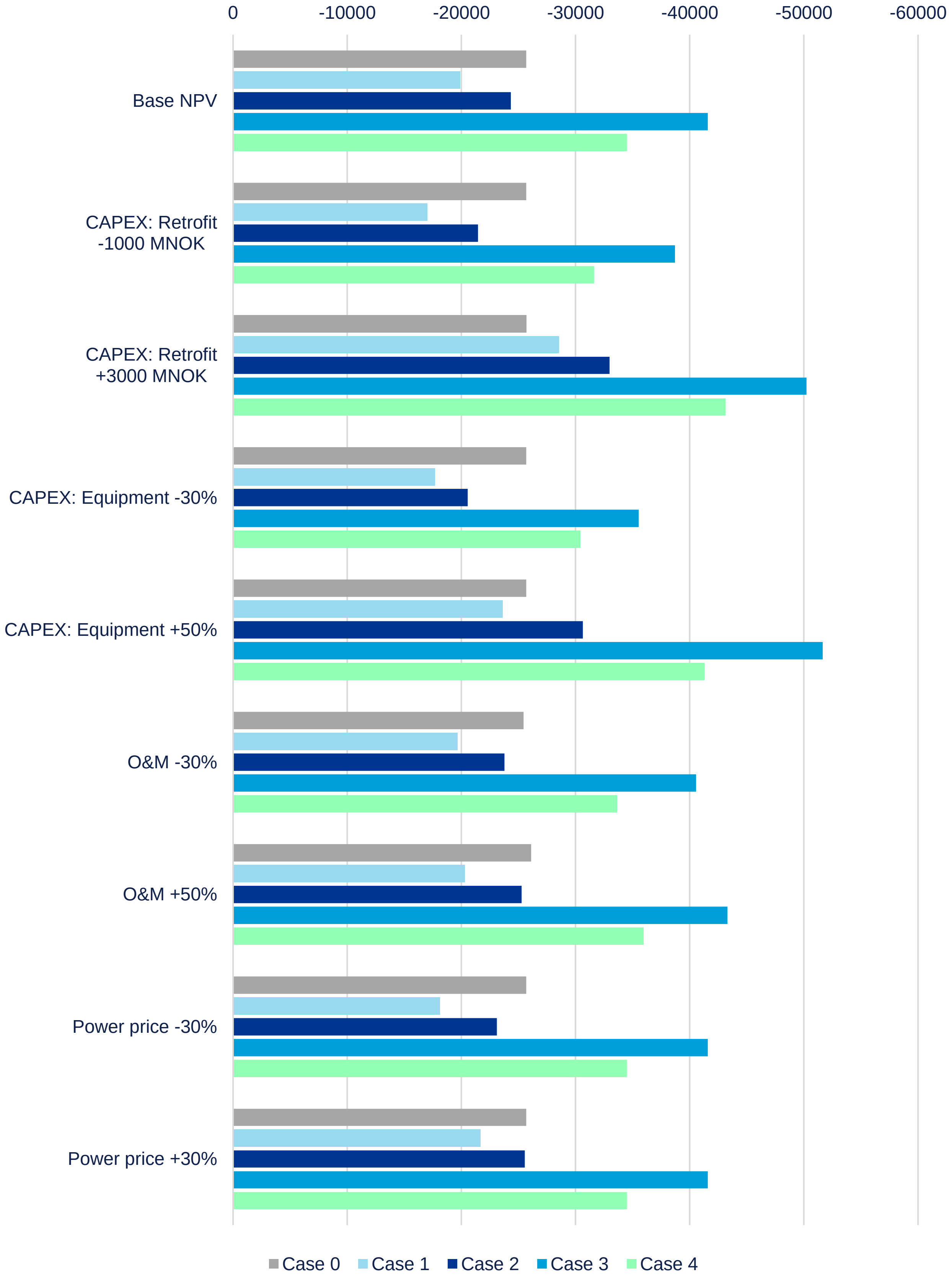


Figure 6-6: Resulting NPV [in 1000 MNOK] for each case when varying key parameters (1/2)

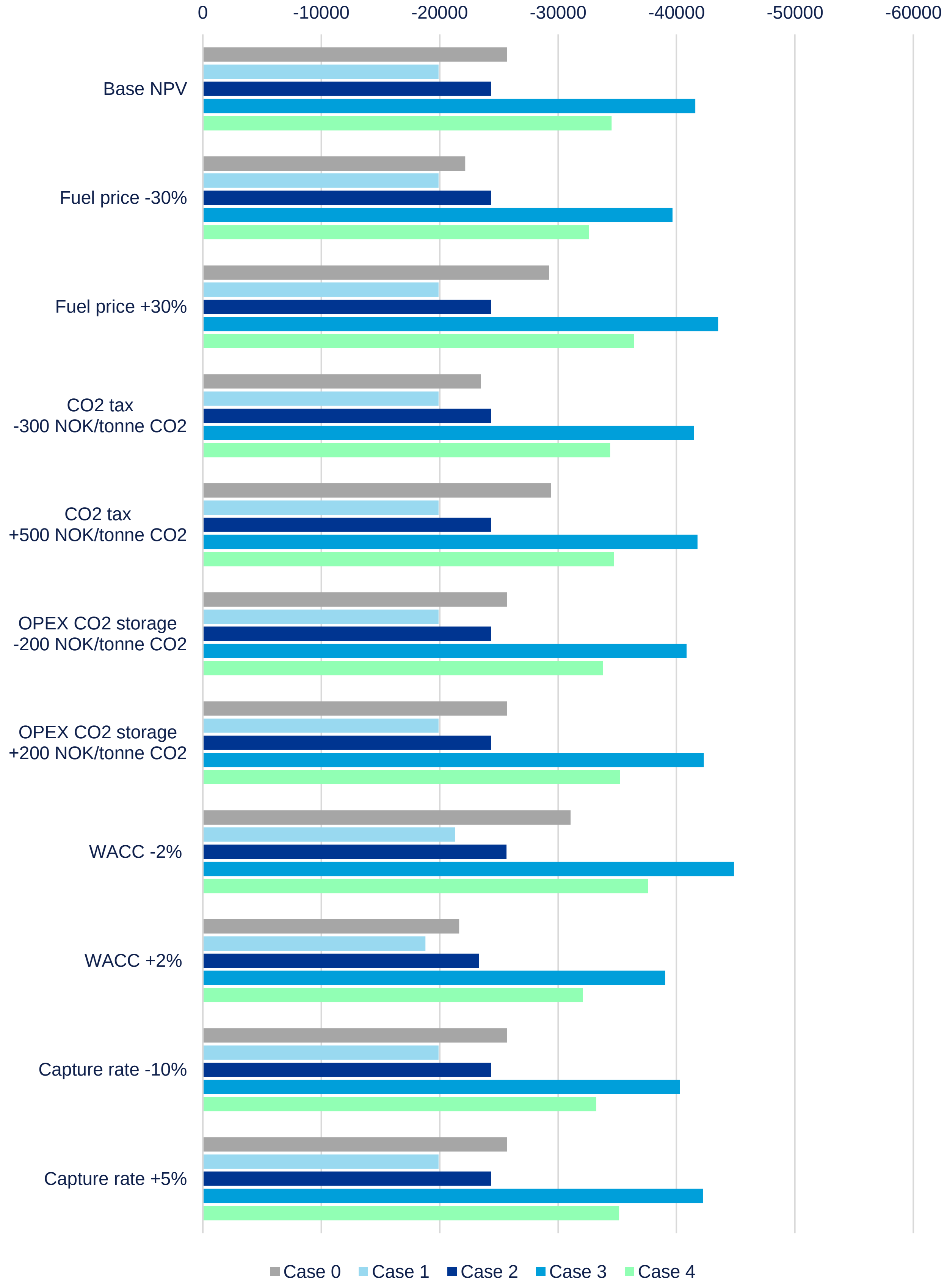


Figure 6-7: Resulting NPV [in 1000 MNOK] for each case when varying key parameters (2/2)

7 CLOSING THE GAP: EXPLORING ALTERNATIVE SOLUTIONS TO REDUCE HARD-TO-ABATE EMISSIONS

The Norwegian oil and gas industry has committed to scope 1 emissions reductions of 50% by 2030 and 90-95% by 2050 from 2005 levels. While these targets are voluntary, they align with Norway's and EU's climate goals. Achieving them will require tackling the remaining, hard-to-abate emissions sources, such as flaring and certain operational activities. To address these emissions, the industry is exploring carbon removal solutions, including options like Direct Air Capture (DAC) and Direct Ocean Capture (DOC), as well as participating in voluntary carbon markets.

In summary, DNV finds that Norwegian oil and gas companies can technically purchase voluntary carbon credits to offset emissions and meet their industry targets, as these targets are not legally binding. However, the current situation presents some important risks in doing so:

1. **It will (currently) not count under the EU ETS:** The Norwegian oil and gas companies are part of the EU Emission Trading System (ETS), meaning they must comply with strict requirements that limit how much CO_2 they can emit by either reducing emissions directly or buying carbon allowances to cover their emissions. Since the EU ETS does not currently allow the use of voluntary carbon credits, any emissions reductions achieved through such credits will not reduce the company's obligations under the ETS. They will still need to buy or surrender enough carbon allowances to cover all emissions, limiting the financial incentive to invest in carbon removal projects outside of own operations.

2. **It is not aligned with best practices and could pose significant reputational risks:** Using voluntary carbon credits does not align with best practices, which emphasise prioritising direct emissions reductions before relying on carbon credits. Using these credits to claim emission reductions could expose companies to greenwashing accusations and reputational risks.

Despite current restrictions, the regulatory landscape is evolving, which **could open up opportunities for Norwegian oil and gas companies to offset emissions through certified carbon removal projects.** Recent EU policy changes recognise the crucial role of carbon removal in reaching climate targets, especially for sectors where reductions are challenging, with the Commission required by 2026 to evaluate how carbon removal projects within the EU can be integrated into the ETS. The Commission is also working on a certification framework for carbon removals, which will set quality standards for carbon removal projects within the EU.

For carbon removal to be a viable tool for offsetting industry emissions, the following factors will be essential:

- **Regulatory adaption:** Policy shifts within frameworks like the EU ETS will be necessary to recognise carbon removal credits, ensuring they can complement direct emission reductions. The anticipated certification framework for carbon removals will play an important role by establishing standards to verify their credibility.

- **Focus on long-term CO_2 storage and additionality:** Best practices for carbon removal emphasise technologies with long-term CO_2 storage, ensuring durability. Credits should meet standards of additionality, proving they would not be viable without carbon credit revenue and that they contribute beyond Norway's national targets.

- **Targeted financial incentives:** Effective incentives – such as tax benefits, auction schemes, or investment support – can reduce barriers to entry, making it feasible for companies to integrate carbon removal projects into their decarbonisation strategies.

In conclusion, while Norwegian oil and gas companies face current limitations in using carbon credits to offset emissions within regulatory frameworks, ongoing policy developments may soon unlock this potential, provided that strict quality standards and robust certification systems are in place.

Important terms

- **Carbon credits:** Certificates representing the reduction, avoidance, or removal of one tonne of CO_2 from the atmosphere, which can be traded on voluntary carbon markets.
- **Carbon removal credits:** Carbon removal, or carbon dioxide removal (CDR), credits are the gold standard, as credits are generated from projects that actively remove CO_2 rather than just reducing emissions.
- **Carbon allowances:** Permits that companies must hold under the EU ETS to legally emit a certain amount of CO_2. Each allowance equals one tonne of CO_2.
- **Compliance carbon markets:** Regulated systems, like the EU ETS, where companies must buy and trade allowances to emit CO_2. These markets are mandatory for industries subject to emissions caps and are designed to meet national or international climate goals.
- **Voluntary carbon markets (VCMs):** Markets where companies or individuals voluntarily purchase carbon credits to offset emissions not regulated by mandatory systems.

7.1 Can oil and gas companies offset their emissions by purchasing carbon credits or investing in carbon removal projects?

The answer is both yes and no, as explained below. In short, the current EU framework sets strict requirements that limit the potential and financial incentives for doing so. However, regulatory developments may soon open up opportunities for Norwegian oil and gas companies to offset hard-to-abate emissions through carbon removal credits generated by their own projects or purchased from others within the EU.

To gain a foundational understanding of carbon credits and carbon markets before diving deeper into the discussions, we recommend reading the short introduction provided in Appendix F.

A short explanation to the link between investing in carbon removal projects and purchasing carbon removal credits

By investing in a carbon removal project, a company can either use the generated credits to offset its own emissions or sell them to earn revenue. Companies can also buy carbon removal credits on voluntary marketplaces to offset emissions. Throughout this chapter, we use the term “carbon removal credits” or “CDR credits” interchangeably to refer to credits generated from these projects, irrespective of ownership. There are other types of carbon credits, although carbon removal credits represent the gold standard.

7.1.1 The current situation presents limited opportunities

While Norway has multiple climate targets, each with different requirements for achieving emissions reductions[136], the Norwegian oil and gas industry’s goals are somewhat aligned but differ in some important ways.

- Under the **Paris Agreement**, Norway has a target of 55% emission reductions by 2030 from 1990 levels. This target will be achieved in collaboration with the EU through the climate agreement, which allows for the use of carbon allowances from other EU/EEA countries. If Norway fulfils its obligations under the climate agreement

[136] https://www.energiogklima.no/nyhet/sporsmal-og-svar-om-norges-klimamal

with the EU, but without this being sufficient to fulfil its obligations under the Paris Agreement, Norway can use carbon credits from outside the EU per Article 6. More details are provided in Chapter 7.1.1.1.

- The **Norwegian Climate Act** legally mandates a 55% emission reduction by 2030 and 90-95% by 2050 from 1990 levels. It does not state how Norway will achieve these targets or how much of the emission reductions that must be made within Norwegian borders.
- In addition, the current government's political platform (*Hurdalplattformen*) has a **transition target** of 55% emission reductions in 2030 compared to 1990 levels. In contrast to the abovementioned targets, this target must be made within Norwegian borders but is not legally binding.

The Norwegian oil and gas industry's targets are voluntary and do not directly align with these national legally binding targets. While companies theoretically could purchase voluntary carbon credits to offset emissions, these credits do not currently satisfy EU ETS obligations as described in Chapter 7.1.1.2, limiting financial incentives for companies to invest in carbon removal projects outside of their own operations. Moreover, these credits would not contribute towards Norway's national targets, and there is a risk that the government may discourage heavy reliance on voluntary offsets to address scope 1 emissions. Finally, using carbon credits to offset scope 1 emissions is not in line with industry best practices, as described in Chapter 7.1.3, which could impact both the industry's and individual companies' reputations.

7.1.1.1 The UN Paris Agreement

The Paris Agreement, adopted by 196 Parties under the UN Climate Change Conference (COP21) in 2015, is a legally binding international treaty, with the aim to limit global warming to well below 2°C, with a target of staying under 1.5°C. Countries set their own national determined contributions (NDCs) as part of this global effort. Norway has committed to achieving its NDCs alongside the EU, with this agreement being legally binding.

Article 6 of the Paris Agreement allows countries to cooperate by trading **internationally transferred mitigation outcomes (ITMOs)**, essentially carbon credits generated in one country that can help another country meet its NDCs[137]. To avoid double-counting, a corresponding adjustment (CA) mechanism ensures that only one country can claim the emissions reduction.

It is important to note that carbon credits traded on voluntary carbon markets (VCMs) are not the same as ITMOs. While voluntary carbon credits are used by companies to meet non-regulatory environmental targets, they do not meet the same regulatory standards as ITMOs, often face issues like double-counting. This limits their effectiveness in fulfilling national-level climate goals under the Paris framework.

There is still some uncertainty about how Article 6 of the Paris Agreement will affect the VCMs, as Article 6 does not directly regulate the VCMs. Some experts argue that VCM credits might become interchangeable with Article 6 credits, which would mean VCM rules would need to align with Article 6 guidelines, like corresponding adjustments (CAs). It is also unclear whether major credit registries, like Gold Standard and Verra, will update their methods to match Article 6, or if countries will prefer to attract investment through Article 6 carbon markets rather than the VCMs[138].

7.1.1.2 The EU framework

In contrast to the Paris Agreement, the EU climate framework is focused on domestic reductions, with a legally binding target of at least a 55% reduction in emissions by 2030 (compared to 1990) [139]. Moreover, EU aims to achieve net-zero by 2050. The EU achieves this through the EU ETS for high-emitting sectors and the Effort Sharing Regulation (ESR)

[137] More details on Article 6 of the Paris Agreement can be found in the Appendix.

[138] Fattouh, B., and Maino A. (2022): Article 6 and Voluntary Carbon Markets, The Oxford Institute for Energy Studies, OIES Energy Insight: 114; available at: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2022/05/Insight-114-Article-6-and-Voluntary-Carbon-Markets.pdf

[139] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32021R1119

for non-ETS sectors. Norway has no obligations towards the EU to reduce emissions covered by the EU ETS but is obliged to reduce emissions covered by the ESR (non-quota-liable sectors).

Currently, the EU ETS only recognises emissions reductions within its boundaries and does not allow for carbon credits to fulfil obligations. This means that companies can only reduce their compliance obligations by reducing emissions directly at their own facilities, such as from capturing CO_2 from their own emissions, or purchasing EU ETS allowances. The system is designed to progressively reduce the total number of carbon allowances available, ensuring a tightening carbon budget resulting in increased costs of emitting CO_2. Towards 2030, the available allowances will be reduced by 62% compared to 2005 levels, pushing companies to invest in emission reduction technologies or purchasing the increasingly scarce and expensive allowances to cover their emissions. By 2050, the number of allowances will likely be drastically reduced in line with the EU's net zero target, with any remaining emissions likely needing to be balanced by carbon removals.

Under the Paris Agreement, the EU submits a common NDC on behalf of the EU and all member states. In the recent version, EU clarified that it will not use international[140] carbon credits (ITMOs) to achieve their 2030 target, and that Article 6 of the Paris Agreement will only be used to account for the exchange of ETS allowances with EEA countries, such as Norway and Iceland[141]. As such, countries cannot meet their obligations under the ESR using carbon credits. This was confirmed when the Commission's proposal to amend an accounting regulation under the ESR approved in April this year[142], explicitly stating that negative emissions are excluded when countries calculate their emissions under the ESR.

Norway has notified the UN that carbon credits on emission reductions in accordance with Article 6 can be used to meet the country obligations under the Paris Agreement that may not be achieved through climate cooperation with the EU[143]. In their recent climate status and action plan, the Norwegian government states that *"it will be challenging to reach the emission targets until 2030 with national emission cuts alone. (…) The government plans to use some flexible mechanisms, such as buying quotas from other EU countries (…) to meet the commitment"[144].*

7.1.2 Future developments could open up opportunities

Although the current regulation does not allow for the use of carbon credits, **the rules around carbon dioxide removal (CDR) technologies are evolving, which could open up opportunities for Norwegian oil and gas companies to offset hard-to-abate emissions.**

In connection with recent regulatory changes, the EU Commission issued a statement acknowledging the key role that industrial carbon removal will play in meeting the EU's climate goals and compensating for emissions from sectors with limited reduction potential. In the revised ESR, the Commission was requested to address how negative emissions accounting could be included, once a final adoption of the Carbon Removal Certification Framework (CRCF) is in place. This framework is expected by 2024, at aims to promote high-quality carbon removal projects within the EU[145].

In addition, Article 30(5) of the revised EU ETS states that by July 31, 2026, the Commission must evaluate how CDR projects within the EU can be included in the EU ETS. This would allow participants to offset a share of their emissions by purchasing these carbon removal credits. Another option could be to create a separate regulated market for negative emissions (carbon removals) that might later connect to the EU ETS.

[140] Outside the EU or EEA
[141] https://unfccc.int/sites/default/files/NDC/2023-10/ES-2023-10-17%20EU%20submission%20NDC%20update.pdf
[142] https://www.altinget.no/klima/statsradensvarer/14803
[143] https://www.energiogklima.no/nyhet/sporsmal-og-svar-om-norges-klimamal
[144] https://www.regjeringen.no/no/aktuelt/forsterker-klimapolitikken/id3057428/
[145] More details on the CRCF can be found in the Appendix

However, strict standards would be needed to maintain the system's decarbonisation goals, including robust certification frameworks to ensure the CDR projects are measurable, verifiable, and permanent. Moreover, according to best practices further elaborated below, carbon credits generated from CDR projects must avoid double-counting, meaning reductions used to create credits should go beyond what is required to meet a country's national targets. The project must also demonstrate additionality, proving that they wouldn't have occurred without financial support from carbon credit revenues and should contribute beyond Norway's national targets.

To enable companies to successfully integrate carbon removal projects into their decarbonisation strategies, effective incentives reducing barriers to entry will be important. This will help reduce costs of investments which could further reduce the cost of purchasing carbon removal credits. Although no concrete incentives are in place in Norway yet, a recent study by Oslo Economics for the Norwegian Environmental Agency emphasised that a carbon contract for difference auction scheme could provide the necessary incentives to support investment in carbon removal projects[146].

7.1.3 Best practice for offsetting emissions should be followed

Carbon credits and offset projects have faced increasing criticism in recent years, with recent reports finding that fewer than 10% of offsetting projects meet quality standards[147]. This is due to issues related to **over-crediting**, **lack of durability and additionality**, **greenwashing**, **double counting**, and **negative local impacts**. For more information on these key issues, please refer to Appendix F.3.

To limit these issues, the **Oxford Offsetting Principles**, introduced in 2020 and updated in 2024, provide guidance on net-zero aligned offsetting. The four key elements are[148]:

1. Prioritise reducing your own emissions first, ensure the environmental integrity of any offsets used, and disclose how offsets are used;
2. Shift offsetting towards carbon removal, where offsets directly remove carbon from the atmosphere.
3. Shift offsetting towards long-lived storage, which removes carbon from the atmosphere permanently or almost permanently; and
4. Support for the development of a market for net zero aligned offsets.

The first principle is particularly relevant to the oil and gas industry's climate targets, emphasising the need for actors to reduce emissions from within **their own value chain as much as possible**, and to invest in mitigation outside their value chains to contribute towards net zero. Direct emissions reduction is important because there are limits to the global capacity for removals. According to the Oxford Principles, the volume of residual emissions is industry specific, based on available technologies, equity, and inclusivity. However, criteria to classify emissions as residual or unavoidable should be revisited regularly with technological progress.

The second and third principles state that companies should prioritise CDR projects which securely store CO_2 for several centuries. Examples include Direct Air Capture and Storage (DACCS), bioenergy with carbon capture and storage (BECCS), other biomass-based methods (BioCCS) chemically binding CO_2 permanently into products, as well as the more novel Direct Ocean Capture and Storage (DOCCS).

The **Science Based Targets initiative (SBTi)** echoes this approach, emphasising that companies should only use carbon credits to support global goals (i.e., the Paris Agreement climate goals), not to claim they have met own targets of reducing emissions. According to the SBTi's "mitigation hierarchy", priority should be given to implementing measures

[146] https://www.miljodirektoratet.no/aktuelt/fagmeldinger/2024/mars-2024/virkemidler-for-industriell-karbonfjerning/

[147] Carbon Direct (2023): State of the Voluntary Carbon Market.

[148] https://www.ox.ac.uk/news/2020-09-29-oxford-launches-new-principles-credible-carbon-offsetting; University of Oxford (2020): The Oxford Principles for Net Zero Aligned Carbon Offsetting, Smith School of Enterprise and the Environment, available at: https://www.smithschool.ox.ac.uk/sites/default/files/2022-01/Oxford-Offsetting-Principles-2020.pdf

towards emissions reduction within the companies' own value chains. Only when they have reached net-zero can companies with residual emissions within their value chain "*neutralize those emissions with an equivalent amount of carbon dioxide removals*" from removal-based carbon credits.[149]

SBTi has developed methodologies for emission reduction target setting in line with climate science and the Paris Agreement goals. An oil and gas-specific methodology is still under development, causing much debate[150], and SBTi has currently paused all commitments and validations of targets from the fossil fuel sector[151]. Until (and if) this is finalised, carbon offsets are generally not accepted for offsetting avoidable scope 1 or 2 emissions under science-based targets towards 2030[152], although developments in EU ETS frameworks might allow for the use of durable carbon removal credits as outlined above.

149 https://sciencebasedtargets.org/resources/files/Beyond-Value-Chain-Mitigation-FAQ.pdf
150 https://sciencebasedtargets.org/sectors/oil-and-gas#the-oil-and-gas-standard-expert-advisory-group
151 https://sciencebasedtargets.org/sectors/oil-and-gas#what-is-the-sb-tis-policy-on-fossil-fuel-companies
152 https://sciencebasedtargets.org/resources/files/Net-Zero-Standard.pdf; https://www.inogenalliance.com/blog-post/pros-and-cons-carbon-offsets

8 CHARTING THE COURSE: A ROADMAP TO NEAR-ZERO EMISSIONS IN 2050

The main purpose of this study is to evaluate how the Norwegian oil and gas industry can achieve near-zero direct emissions by 2050 whilst maintaining high production. This roadmap outlines a potential pathway, highlighting both the technological solutions available and the important initiatives that can enable a successful transition. Rather than showing a fixed future, our roadmap aims to inspire actionable dialogue on where to prioritise decarbonisation efforts, identifying key success factors and addressing the R&D focus areas necessary to meet the industry's ambitions.

8.1 What will it take to achieve near-zero emissions in 2050?

Our roadmap (illustrated in Figure 8-1) shows the potential within each decarbonisation pathway discussed in Chapter 5, presenting a range of emission reduction possibilities based on different technological and operational choices. This range underscores the need for a high level of commitment and collaboration across the industry. If the maximum decarbonisation potential is realised, **the sector could achieve a 93% reduction in emissions compared to 2005 levels, meeting the 2050 target.** However, realising this goal will require an accelerated adoption of key technologies, targeted R&D investments, and coordinated efforts across all disciplines. **If the full potential is not realised, there is a risk that the target will not be met.**

For emissions that remain beyond the reach of current technological solutions, high-quality carbon removal credits – such as from DAC or other carbon removal technologies – could be an option. However, their future use is uncertain, and advancements in regulatory frameworks, such as the potential recognition within the EU ETS, will be necessary to allow carbon removals to complement direct reductions towards meeting the 2050 target.

It is important to note that our findings are based on a series of assumptions affecting the results, notably regarding emission potential in 2050, the share of production from existing installations, the amount of drilling required, and more. For a full overview of the assumptions used in developing this roadmap, please refer to Chapter 8.2.

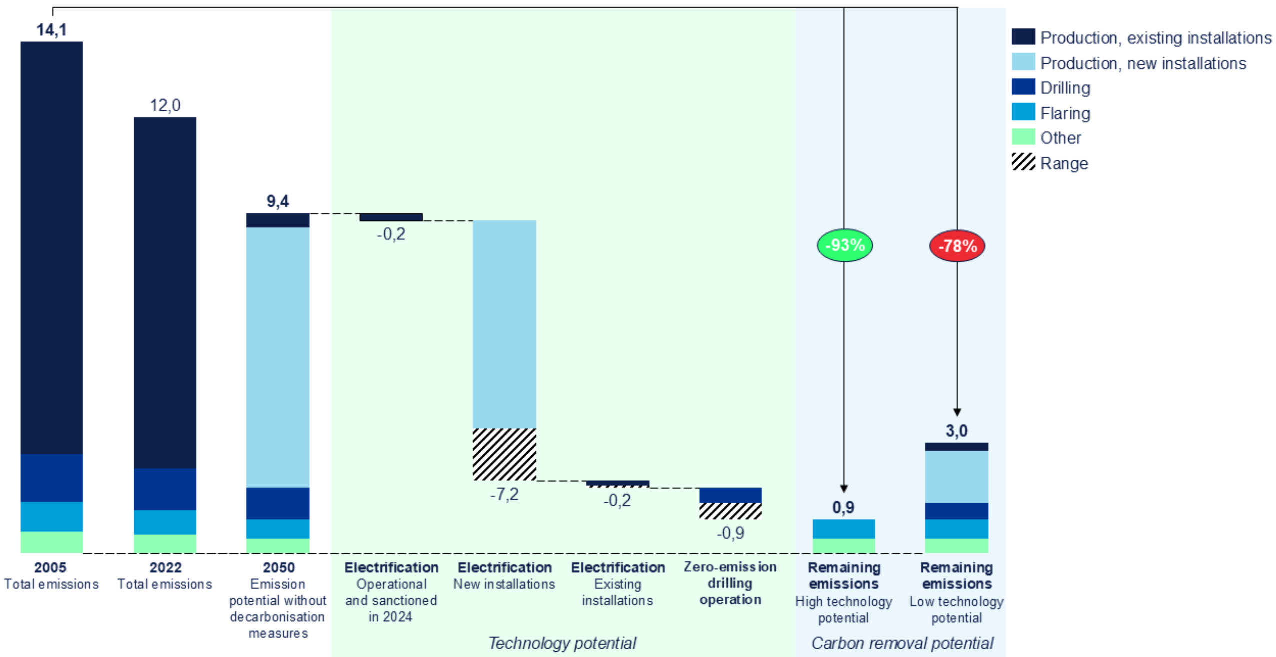


Figure 8-1: Roadmap to emission reductions in 2050 under NOD's high scenario [million tonnes CO_2e]

8.1.1 Technology potential and key factors for success

Within the technology potential, our roadmap provides a merit order on electrification measures, prioritising the simplest and most cost-effective solutions. Zero-emission drilling will also be essential for reaching near-zero emissions. Our findings highlight that the vast majority of emission reduction potential lies in electrifying new installations. As shown in the case study results (see Chapter 6.3), new installations should prioritise electrification from the outset to avoid the significant costs associated with retrofitting and can provide significant cost savings compared to business as usual.

For brownfield assets, full electrification of non-electrified assets remains challenging and costly and may not be economically viable if retrofitting expenses are high. Given the limited emissions expected to remain from these assets, full electrification will likely not be the measure that moves the needle. However, by strategically deploying decarbonisation technologies, both new and existing assets can achieve substantial reductions, especially where solutions are selected to match specific project conditions.

In our roadmap, the emission reduction potential of different electrification measures – including power-from-shore, offshore wind, and gas-fired power with CCS – has been bundled together, as these solutions offer comparable means of emission reduction, albeit with unique strengths and challenges. The preferred solution for each case will ultimately depend on specific project characteristics.

To realise the full technological potential, the following success factors should be prioritised:

- **Coordinated electrification strategies** to establishing shared infrastructure, such as power hubs serving multiple fields, can enhance scalability, improve resource utilisation, and generate significant cost savings. A grid-integrated offshore power system offers long-term benefits by ensuring a secure power supply and supporting the broader energy system as oil and gas production declines.
- **Focusing R&D on adaptable technologies with applications beyond the petroleum sector** can accelerate technology development and leverage economies of scale. Subsea power grids, for example, can benefit from scaling across other offshore industries, such as wind power, which will enable technological maturity and cost reduction through broader applications.
- **Predictable, long-term policy frameworks** are essential to enable high-stakes investments in decarbonisation initiatives. A clear policy direction will help mitigate project delays, especially in projects like power-from-shore where competition for grid capacity is a persistent issue. The need for a holistic energy plan with clear and predictable policy frameworks has also been highlighted in OG21's 2023 Annual Report[153].
- **Investing in large-scale build-out of new power generation** at competitive prices is essential in enabling power-from-shore solutions. There is an opportunity for the industry to take an active part in this, not only supporting electrification of the petroleum sector, but also the wider Norwegian industry.

In addition to these overarching success factors, each technology presents unique challenges that require focused R&D to unlock their full decarbonisation potential and make them viable at scale. Below, we outline the primary challenges and selected R&D efforts required to address them. More details can be found in Chapter 5.

[153] OG21, 2023, Årsrapport for 2023, og21-arsrapport-2023.pdf

Power-from-shore

Key challenges: Limited onshore grid capacity necessitates large-scale build-out of new power generation to meet the growing demand, especially for offshore electrification. Long-distance connections require high-voltage direct current (HVDC) systems, which face challenges related to space constraints, global supply limitations on cables and converters, and lower maturity for ship-based FPSO electrification.

R&D focus areas: Develop modular, standardized HVDC equipment to improve supply chain resilience and cost-effectiveness. Innovate in subsea or compact equipment to reduce topside footprint. Further advance dynamic DC cables and DC turrets for ship-based FPSOs to enhance flexibility, as well as long-distance HVAC.

Offshore wind

Key challenges: Intermittent power generation means backup is required to ensure continuous supply. The specific emission reduction potential varies by configuration, and zero-emission backup solutions are less developed than conventional gas turbines. For deep waters on the NCS, floating wind is predominantly needed, though it currently faces higher costs and lower maturity than bottom-fixed options.

R&D focus areas: Standardize designs for floating turbines, enhance floating platform and mooring systems, and strengthen supply chains to reduce costs. Develop dynamic DC cables for shore connections. For off-grid solutions, focus on developing zero-emission back-up systems, such as large-scale batteries and hydrogen storage.

Gas-fired power with CCS

Key challenges: Emission reductions rely on high capture rates, yet current amine-based capture systems often perform below the anticipated 90% efficiency. Offshore units are at early development stages, facing lower maturity compared to onshore systems. CO_2 transport and storage infrastructure remains limited, and challenges such as flow assurance, corrosion, and high capture system costs persist.

R&D focus areas: Innovate in capture technology, especially promising novel capture methods, to improve efficiency, real-world capture rates, and reliability while bringing down costs. Further innovate on equipment design, such as modular and compact solutions for cost reductions and standardisation. Increase collaboration, learning, and knowledge sharing to avoid cost overruns and project delays. Further develop transport and storage solutions to reduce costs and increase availability of supportive CCS infrastructure.

Zero-emission drilling

Key challenges: Retrofitting is more feasible than new builds due to extended construction times and financing constraints. Full electrification is limited by the need for long power cables, and biofuel supply faces challenges related to supply. Other low-carbon fuel alternatives present challenges such as toxicity, storage limitations, low maturity, and high costs.

R&D focus: Retrofit kits for alternative fuels are key to transforming the existing fleet. Focus on improving rig efficiency to enable dual-fuel operations, and further pilot and test rig operations using alternative fuels. Increase availability of affordable, low-carbon fuel supply. Additionally, a coordinated push from government through available funding, and pull from operators through long-term contracts at favourable day rates, will be essential to justify investment in zero-emission upgrades.

8.1.2 Carbon removal potential and key factors for success

While maximizing direct emissions reductions through technology is essential, some emissions will likely remain beyond the reach of electrification and operational efficiencies alone. Addressing these residual emissions will require high-quality carbon removal technologies, such as DACCS, BECCS or DOCCS, which can offer a viable pathway to offset hard-to-abate emissions.

However, within the current framework, companies can only reduce their compliance obligations to the EU ETS by reducing emissions directly from their own operations. To enable the use of carbon removal credits from such projects, they would need to be recognised within the EU ETS. There are ongoing discussions on how this could be implemented, with results expected by 2026. Should carbon removal credits be accepted for compliance, a robust certification process – such as the one currently under development by the EU Commission – will be essential to ensure these credits are measurable, verifiable, and meet quality standards.

In summary, for carbon removal credits to be a viable tool for offsetting industry emissions, the following factors will be essential:

- **Regulatory adaption:** Policy shifts within frameworks like the EU ETS will be necessary to recognise carbon removal credits, ensuring they can complement direct emission reductions. The anticipated certification framework for carbon removals will play an important role by establishing standards to verify their credibility.
- **Focus on long-term CO_2 storage and additionality:** Best practices for carbon removal emphasise technologies with long-term CO_2 storage, ensuring durability. Credits should meet standards of additionality, proving they would not be viable without carbon credit revenue and that they contribute beyond Norway's national targets.
- **Targeted financial incentives:** Effective incentives – such as tax benefits, auction schemes, or investment support – can reduce barriers to entry, making it feasible for companies to integrate carbon removal projects into their decarbonisation strategies.

By combining technology-driven emissions reductions with high-quality carbon removals for residual emissions, the Norwegian oil and gas industry can pursue a credible pathway to near-zero emissions by 2050.

8.2 Key assumptions underpinning the roadmap

The roadmap presented in this study is based on a series of assumptions that shape the projected emissions reduction potential. Given the inherent uncertainties in forecasting up to 2050, these assumptions are necessary to create a structured and realistic pathway but should be revisited regularly as conditions and technologies evolve. Below, we summarise the main assumptions made in our analysis:

- Historical emissions data (2005 and 2022): Using the emissions as reported by SSB. For more detail, see Chapter 3.2.2.
- Share of emissions from the different sources (production, drilling, flaring, other): Using the current (2022) NCS average share of emissions from the different sources. For more detail, see Chapter 3.2.2. There are regional differences in the share of emissions, but these are not considered as we do not have all the relevant information required to do so (e.g., future infrastructure build out in the Barents).
- Production from existing vs. new installations: Assuming all reserves and contingent resources in fields are allocated to existing installations, while all contingent resources in discoveries and undiscovered resources are allocated to new installations. This is based on the definition of maturity in the NOD resource report. For more detail, see Chapter 4.2.

- Change in activity: The change in emissions from 2022 to 2050 under NOD's high production scenario, given the assumed emission potential in 2050 (see below). For more details, see Chapter 4.2.
- Emission potential 2050: Using the baseline on emission potential in 2050 under NOD's high production scenario. For more details, see Chapter 4.2.
- Electrification (operational and sanctioned 2024): Assuming electrified installations (already operational or sanctioned, see also Chapter 4.2) will continue to be operational in 2050. The emission reduction potential from the 2050 baseline is based on existing installations only and is estimated using the same percentage share of emission reduction achieved in 2030 (when all sanctioned measures are assumed operational) against total production emissions from existing installations[154].
- Electrification (new installations): Assuming full electrification of all new installations. The range provided is dependent on the selected mode of electrification. With power-from-shore using a renewable grid mix, a full emission reduction could be achieved. Using dedicated power from a gas power plant with CCS, the emission reduction potential depends on the capture rate and emissions from transport and storage. Here, a conservative estimate assumes 80% emission reduction potential. For more detail on CCS, see Chapter 5.4.
- Electrification (existing installations): Assuming full electrification of existing installations not already electrified. The same assumptions on the range of emission reduction potential are applied as for new installations.
- Drilling (zero emissions): Assuming zero emission drilling rigs. The range is given as an uncertainty range of 50% on the amount of drilling rigs that will be zero emission in 2050.
- Remaining emissions: Shows the remaining emissions in 2050 assuming all decarbonisation measures are implemented. The low scenario reflects the highest share of decarbonisation potential within each measure, while the high scenario reflects the lowest share.

[154] Historical and sanctioned emission reduction potential is based on the following analysis by Energi og Klima: https://www.energiogklima.no/nyhet/disse-feltene-far-kraft-fra-land-innen-2030

APPENDIX

A List of abbreviations

ABBREVIATION	DESCRIPTION
AC	Alternating Current
AMP	2-amino-2-methyl-1-propanol
APS	IEAs Announced Pledges Scenario
BECCS	Bioenergy with carbon capture and storage
CAPEX	Capital expenditures
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CDR	Carbon dioxide removal
COP28	UN's 28th Climate Change Conference
CRCD	Carbon removal certification framework
DAC	Direct air capture
DACCS	Direct air capture and storage
DC	Direct current
DOC	Direct ocean capture
ETN	DNV's Energy Transition Norway report
ETO	DNV's Energy Transition Outlook report
EU	European Union
EU ETS	European Union Emissions trading system
FEED	Front-end engineering
FID	Final investment decision
FOAK VS NOAK	First-of-a-kind vs Nth-of-a-kind
FPSO	Floating production, storage, and offloading unit
FWT	Floating wind turbine
GHG	Greenhouse gas
GIS	Gas insulated switchgear
HVAC	High voltage alternating current
HVDC	High-voltage direct current
HVO	Hydrogenated vegetable oil
IEA	International Energy Agenda
IPCC	The Intergovernmental Panel on Climate Change
ITMO	Internationally transferred mitigation outcomes
JIP	Joint industry project
LCOE	levelized cost of energy
LFAC	Low-frequency alternating current
LNG	Liquefied natural gas
LO	Confederation of Trade Unions
MCR	Main component replacement
MEA	Monoethanolamine
NCS	Norwegian Continental Shelf
NDC	Nationally Determined Contribution

NGCC	Natural gas + carbon capture plant
NHO	Confederation of Norwegian Enterprise
NOD	Norwegian Offshore Directorate
NPV	Net Present Value
NZE	IEA net-zero emission scenario
O&G	Oil and gas
O&M	Operations and maintenance
OPEX	Operational expenditures
PZ	Piperazine
R&D	Research and development
REDII	Renewable Energy Directive – Recast to 2030
SBTI	Science based targets initiative
SSB	Statistics Norway
TAM	Total addressable market
TG	Technology group
TLP	Tension-leg platform
TRL	Technology readiness level
VCM	Voluntary carbon markets
VSC	Voltage-source converter

B Technology mapping and evaluation

This appendix presents the full set of technologies that were initially considered for reducing scope 1 emissions from Norwegian oil and gas operations. The evaluation includes key criteria such as technology maturity, scale-up timelines, and potential obstacles.

The work was conducted in a phased manner, starting with a technology mapping exercise. This involved identifying a long list of potential technologies, which were then evaluated against specific criteria such as emission reduction potential, technical maturity, scale-up timeline and potential, and main risks. Following this, a screening process was implemented to select a shortlist of promising technologies. For each shortlisted technology, an in-depth analysis is performed (see Chapter 5).

B.1 Technology mapping

The first step of the phased approach was to identify a wide range of technologies with a possible potential for reducing scope 1 emissions. The mapping exercise was performed in two separate workshop sessions alongside the five Technology Groups (TGs) of OG21, resulting in a long list of technologies. The list was further narrowed down to 21 selected technologies for evaluation and screening. The full list of technologies alongside a short reasoning for including/excluding them for the screening exercise is shown in the table below.

Decarbonisation measure for scope 1 emissions	Application scope	Selected for evaluation	Reasoning
Electrification: Coordinated from offshore power grid	Replacing gas turbines (partial or full electrification)	**Yes**	Impacts largest emissions source early on

Decarbonisation measure for scope 1 emissions	Application scope	Selected for evaluation	Reasoning
Electrification: Coordinated from onshore power grid	Replacing gas turbines (partial or full electrification)	**Yes**	Impacts largest emissions source early on
Electrification: Geothermal	Replacing gas turbines (partial or full electrification)	**Yes**	Impacts largest emissions source long term
Electrification: Individual from onshore power grid	Replacing gas turbines (partial or full electrification)	**Yes**	Impacts largest emissions source early on
Electrification: Local supply from offshore wind	Replacing gas turbines (partial or full electrification)	**Yes**	Impacts largest emissions source early on
Electrification: Offshore gas-fired power hubs with CCS	Replacing gas turbines (partial or full electrification)	**Yes**	Impacts largest emissions source long term
Electrification: Onshore gas-fired power hubs with CCS, directly connected to platforms	Replacing gas turbines (partial or full electrification)	**Yes**	Impacts largest emissions source long term
Electrification: Onshore nuclear, directly connected to platforms	Replacing gas turbines (partial or full electrification)	**Yes**	Impacts largest emissions source long term
Electrification: Onshore wind, directly connected to platforms	Replacing gas turbines (partial or full electrification)	**Yes**	Impacts largest emissions source early on
Electrification: Small modular reactors	Replacing gas turbines (partial or full electrification)	**Yes**	Impacts largest emissions source long term
Electrification: Floating solar	Replacing gas turbines (partial electrification)	**Yes**	Impacts largest emissions source long term
Electrification: Tidal power	Replacing gas turbines (partial electrification)	**Yes**	Impacts largest emissions source long term
Energy efficiency: Water management for high water cut	Reducing power consumption from injection. Reducing weight of fluid column and need for gas compression gaslift	**Yes**	Impacts large emission source from oil fields
Energy efficiency: Water management for stable	Reducing power consumption from injection	**Yes**	Impacts large emission source from oil fields

Decarbonisation measure for scope 1 emissions	Application scope	Selected for evaluation	Reasoning
displacement (w/ or w/o chemicals)			
Energy efficiency: Heat pumps	Reducing energy consumption from gas turbines	**Yes**	Can reduce energy consumption from gas turbines by utilising waste heat
Compact top-side CCS	Reducing emissions from gas turbines	**Yes**	Impacts largest emissions source long term
Hydrogen and hydrogen-derived fuels in gas turbines	Reducing emissions from gas turbines	**Yes**	Impacts largest emissions source long term
Reduce flaring	Reducing emissions from flaring	**Yes**	Reducing flaring will be important to reduce remaining emissions according to 2050 target
Energy efficiency: Better modelling for reservoir understanding	Reducing emissions from drilling rigs	**Yes**	Potential for reducing number of wells drilled and avoiding sidetracks, estimates of up to 25 - 50% less wells (from TG 2). This reduction is an order of magnitude lower than others on the list but acknowledge importance in the long term for reducing the final few percent of emissions
Zero emission drilling rigs	Reducing emissions from drilling rigs	**Yes**	Impacts second largest emissions source long term
Rigless P&A through use of vessels	Reducing emissions from drilling rigs	**Yes**	Impacts second largest emissions source in medium term
Energy efficiency	Unmanned facilities	No	Likely limited effect on emission reduction
Electrification: Fusion energy	Replacing gas turbines (partial or full electrification)	No	Highly uncertain and still very immature technology
Energy efficiency: Reducing cycling of water	Reducing power consumption from injection	No	Covered in water management topics

Decarbonisation measure for scope 1 emissions	Application scope	Selected for evaluation	Reasoning
Energy efficiency: Drilling mud treatment to reduce chemical useage	Reducing emissions from drilling rigs	No	Likely limited effect on emission reduction
Energy efficiency: Reduce drilling time through better targeted wells	Overarching (ties in with other work on AI and geo modelling)	No	Hard to measure and incremental - reducing direct emissions from drilling is already covered
Electrification: Subsea tie-backs	Overarching	No	Covered by other electrification topics
Energy efficiency: Campaigns of drilling/well operations	Overarching	No	Not a technology solution
Energy efficiency: Subsea intervention	Overarching	No	Likely limited effect on emission reduction
Energy efficiency: Subsea processing	Overarching	No	Likely limited effect on emission reduction
Energy efficiency: Use of AI/ML	Overarching	No	Might be a potential of reducing emissions through efficiency gains, although likely difficult to quantify and will be covered in other measures individually (difficult to isolate measure)
Field management: AI controlled	Overarching	No	Very broad concept - likely covered in other measures individually
Other: Improved collaboration	Overarching	No	Not a technology solution
Other: Reduce personel offshore	Overarching	No	Hard to measure emissions impact
Other: Regulation to keep pace with technology developments	Overarching	No	Not a technology solution
Other: Standardisation of well design	Overarching	No	Likely limited effect on emission reduction

Decarbonisation measure for scope 1 emissions	Application scope	Selected for evaluation	Reasoning
Other: Use of keeper wells i.e. exploration wells that are also designed for production	Overarching	No	Likely limited effect on emission reduction
Other: Well designed for flexible injection profiles	Overarching	No	Hard to measure against and would be part of other technologies covered e.g. electrification using wind
Enhanced oil recovery (EOR)	Increasing lifetime of fields. Impacts on emissions low.	No	Likely limited effect on emission reduction
Optimized gas turbines (batteries for better utilisation)	Improving gas turbine efficiency	No	From a business perspective, investing in more efficient gas turbines is a short-term and not long-term perspective for reducing emissions (not able to reach near-zero with this measure)
Optimized gas turbines (combinded cycle)	Improving gas turbine efficiency	No	From a business perspective, investing in more efficient gas turbines is a short-term and not long-term perspective for reducing emissions (not able to reach near-zero with this measure)
Optimized gas turbines (multiple turbines for better utilisation)	Improving gas turbine efficiency	No	From a business perspective, investing in more efficient gas turbines is a short-term and not long-term perspective for reducing emissions (not able to reach near-zero with this measure)
Optimized gas turbines (STIG)	Improving gas turbine efficiency	No	From a business perspective, investing in more efficient gas turbines is a short-term and not long-term perspective for reducing emissions (not able to reach near-zero with this measure)

Decarbonisation measure for scope 1 emissions	Application scope	Selected for evaluation	Reasoning
Electrification: Blow out preventer (BOP)	Electrification of hydraulics/pneumatics. Impacts on power and emissions unclear.	No	Might impact last emissions sources to reach 2050 targets
Electrification: Electric X-mas tree	Electrification of hydraulics/pneumatics. Impacts on power and emissions unclear.	No	Might impact last emissions sources to reach 2050 targets
Energy efficiency: Alternative lift methods	Alternative lift methods	No	Mulitple technologies that are dependent on electrification and other higher-level methods at the field
Direct injection of exhaust	Reduce emissions from gas turbines	No	Requires very large volumes of pore-space, more complex pre-modelling work to understand the behaviour of the injected gas mix in the subsurface, an order of magnitude higher pressure build-up compared with injection of pure CO_2, along with the considerably energy requirements to compress mostly nitrogen to reservoir pressures without the long experience that exists for CO_2.

B.2 Evaluation of selected technologies

Each selected technology was evaluated based on a set of criteria agreed with OG21. The evaluation was done through an iterative process with inputs being gathered by both subject matter experts in DNV and the OG21 Technology Groups (TGs). **Error! Reference source not found.** table below lists the technologies, categorised into targeted emission reduction measures.

Technology solution	Target emission reduction measure
Electrification: Offshore gas-fired power hubs with CCS	Replacing gas turbines (partial or full electrification)
Electrification: Coordinated from offshore power grid	Replacing gas turbines (partial or full electrification)
Electrification: Coordinated from onshore power grid	Replacing gas turbines (partial or full electrification)

Technology solution	Target emission reduction measure
Electrification: Individual from onshore power grid (radial)	Replacing gas turbines (partial or full electrification)
Electrification: Local supply from offshore wind	Replacing gas turbines (partial or full electrification)
Electrification: Offshore geothermal	Replacing gas turbines (partial or full electrification)
Electrification: Onshore gas-fired power hubs with CCS, directly connected to platforms	Replacing gas turbines (partial or full electrification)
Electrification: Onshore nuclear, directly connected to platforms	Replacing gas turbines (partial or full electrification)
Electrification: Small modular reactors	Replacing gas turbines (partial or full electrification)
Electrification: Floating solar	Replacing gas turbines (partial or full electrification)
Electrification: Wave power	Replacing gas turbines (partial or full electrification)
Heat pumps	Reducing power consumption from gas turbines
Water management for high water cut	Reducing power consumption from injection
Water management for stable displacement (w/ or w/o chemicals)	Reducing power consumption from injection
Compact top-side CCS	Reducing emissions from gas turbines
Hydrogen and hydrogen-derived fuels in gas turbines	Reducing emissions from gas turbines
Zero emission drilling rigs	Reducing emissions from drilling rigs
Rigless P&A through use of vessels	Reducing emissions from drilling rigs
Energy efficiency: Better modelling for reservoir undersanding ("get it right first time" approach)	Reducing emission from drilling rigs
Technologies for reduced flaring	Reduce flaring

The criteria used in the evaluation process of each technology are summarised below.

Criteria	Questions to be answered	Scoring
Technology maturity	How mature is the technology?	High: TRL 9+ (should be deployable at commercial scale)

See information below on technology readiness level (TRL)		Medium: TRL 7-9 (should be close to demonstration projects) Low: TRL <7 (could be years or more from demonstration project)
Obstacles to technology development	How limiting are the obstacles to the technology reaching commercial deployment?	High: TRL 9+ achievable today/without major delay Medium: TRL 9+ achievable by 2030 Low: TRL 9+ achievable by 2040
Scale-up timeline	When would we expect technology implementation at scale?	High: 2030 (commercial deployment across multiple sites relevant for 2030 target) Medium: 2040 (commercial deployment across multiple sites relevant for 2050 target) Low: 2050 (commercial deployment across multiple sites not likely to enable 2050 target)
Obstacles to implementation	How limiting are the obstacles to commercial implementation at scale?	High: Multiple-site commercial deployment can begin construction today/without major delay Medium: Multiple-site commercial deployment can begin construction by 2035 Low: Multiple-site commercial deployment cannot begin construction before 2045+
Industry opportunities	Are there other industry opportunities with this type of technology?	High: Multiple other opportunities available Medium: Some other opportunity available Low: Limited/no other opportunities
Value chain risks	Does this expose you to external value chains?	High: Stand-alone solution Medium: Medium complexity, relies on other value chains to some degree Low: Complex, high chance/history of failure
Technology risks	Are there any significant technology risks?	High: Few technology risks, easily solvable Medium: Some technology risks, solvable within timeframe Low: High and critical technology risks, difficult to solve
Political and societal risks	Are there any societal/political risks involved?	High: High acceptance or active push from politicians and/or society, or neutral Medium: Some opposition in political environment or societal

		Low: High opposition seen, either politically or in society
Environmental risks	Are there any environmental impacts involved (biodiversity, noise, etc)?	High: Few environmental risks Medium: Some environmental risks, solvable within timeframe Low: High environmental risks, difficult to solve
Relative CAPEX	Where does this technology sit in terms of CAPEX vs. the other options?	High: Lower CAPEX Medium: Average/medium CAPEX Low: High CAPEX
Relative OPEX	Where does this technology sit in terms of OPEX vs. the other options?	High: Lower OPEX Medium: Average/medium OPEX Low: High OPEX
Technical GHG emission reduction potential	How much emissions reduction will this technology have on the application scope? *e.g. it can reduce the emissions from a gas turbine by 60%*	High: 90+% (compatible with 2050 target level) Medium: 50-90% Low: <50% (incompatible with both 2030 and 2050 target levels)
Opportunity costs	Will this technology be the most effective in the long term?	High: Best option for emissions reductions, does not prevent further reductions Medium: Good option for emissions reductions, easy to replace/improve in the near future Low: Likely not the best option currently or in the future, risk of locking in low emissions reduction potential

B.3 Note on technology readiness level

Technology readiness levels (TRLs) for the identified technologies is scored based on the IEA's technology readiness level scale as used in their innovation gaps framework[155]. This is particularly relevant as the scale is designed for clean energy technologies and is based on NASA's original TRL scale[156] with adjustments and additional levels relevant to the energy transition. The scale runs from 1 (least mature) to 11 (most mature) as follows:

1. **Initial idea**: basic principles have been defined
2. **Application formulated**: concept and application of solution have been formulated
3. **Concept needs validation**: solution needs to be prototyped and applied
4. **Early prototype**: prototype proven in test conditions

155 https://www.iea.org/reports/innovation-gaps
156 https://www.nasa.gov/directorates/somd/space-communications-navigation-program/technology-readiness-levels/

5. **Large prototype**: components proven in conditions to be deployed
6. **Full prototype at scale**: prototype proven at scale in conditions to be deployed
7. **Pre-commercial demonstration**: solution working in expected conditions
8. **First-of-a-kind commercial**: commercial demonstration, full-scale deployment in final form
9. **Commercial operation in relevant environment**: solution is commercially available, needs evolutionary improvement to stay competitive
10. **Integration at scale**: solution is commercial but needs further integration efforts
11. **Proof of stability**: predictable growth

For conversions between API and IEA/Nasa TRL levels see Yasseri & Bahai (2018)[157].

Scoring and prioritising of technologies

After the input was gathered, the technologies were given scores for each criterion (high, medium, low). The aim was to assess the overarching potential of each technology on a high level, as well as to identify and visualise potential barriers and opportunities. It should be noted that low scores do not necessarily imply that a technology is not relevant for emission reduction, but that there are certain areas that require attention for the full potential to be reached. Please find the scoring attached to this publication.

Based on the scoring and discussions with OG21, four technologies were selected for a deep-dive assessment (see Chapter 5).

C Short description of non-prioritised technologies

Below is a brief description of the non-prioritised technologies.

C.1 Offshore geothermal

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. Onshore geothermal power is a proven technology deployed onshore with over 15 GWe in operation worldwide. There might be a potential for offshore geothermal power plants on the NCS, especially if re-using existing or abandoned oil and gas wells and platforms. However no offshore geothermal power plants are currently operational.

The offshore geothermal concept recovers heat from produced fluids in oil and gas fields to generate power on the platform. Replacing gas turbines at platforms for power production and heat demand by geothermal power plants. Although geothermal plants use some electricity for operation (e.g. ESP-pumps, cooling tower), this can be self-supplied. The theoretical GHG emission reduction potential can be up to 100%. The potential per geothermal power plant is typically broken down into two categories: geothermal binary technology provides 2-3 Mwe, and geothermal flash or dry steam technology provides 17 to 23 MWe[158.]

The realistic reduction potential is case specific and has not been studied in detail for this report. The main requirements for deployment of offshore geothermal energy are geological conditions and subsurface temperatures/flowrates available. The platform should be suitable for the construction of geothermal plant (conversion technology), or a platform in use or close to shore for power distribution if abandoned.

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[157] Yasser & Bahai (2018), https://www.ijcoe.org/article_149297.html

[158] Calculations by DNV based on Zarrouk and Moon (2014) https://doi.org/10.1016/j.geothermics.2013.11.001 The potential 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 typical power plant sizes. In case of "increasing operational platform efficiency' gas turbines on the platform can be replaced by geothermal electricity. For this a reference case of 75 MWe per platform could be used (3x25 MWe gas turbine per platform).

Developing and implementing offshore geothermal energy systems face several significant obstacles. First, there is a limited availability of thermal aquifer systems near offshore platforms that meet the necessary conditions for geothermal energy production, such as high temperatures and mass flow rates. Current analyses indicate that only around 10% of reservoirs on the Norwegian Continental Shelf (NCS) exceed 120°C, with an even smaller percentage above 180°C, though some hot spots do exist. This underscores the need for further assessment of geothermal potential. Additionally, the possibility of repurposing existing oil and gas wells for geothermal use might be constrained by factors like casing, insulation, well heads, and tubing. The harsh offshore environment also presents significant challenges.

The return on investment is another concern, particularly since the remaining lifecycle of a platform should be at least 20 years to justify the investment, or alternative uses for the geothermal plant must be identified. The installation of subsea electricity cables is necessary if power is to be transported to shore, adding to the complexity. Furthermore, obtaining the required permits and licenses for exploration, exploitation, environmental considerations, and grid access can be challenging. The installation of technical rooms on the platform, as well as the higher drilling costs compared to onshore geothermal plants, are additional factors that complicate development.

The offshore geothermal concept itself is quite old but has only begun to be investigated seriously as a viable decarbonisation/efficiency technology in the past few years. The Net Zero Technology Centre in Aberdeen (previously the Oil and Gas Technology Centre) has been working with CeraPhi Energy to investigated how offshore wells can be retrofitted for geothermal with the Magnus Platform in the UK North Sea used as the base case[159].

C.2 Floating solar

Solar panels can be attached to floating platforms and deployed in offshore environments. Solar technology itself is very mature, however the application in the offshore environment is still in the test phase with projects such as SolarDuck running tests with the Merganser pilot in the North Sea[160] and the Teal project in Japan[161]. Offshore wind developers in the Netherlands are also adding floating solar to their projects: 50MW in a joint venture from Vattenfall and CIP[162], and 5MW in RWE's OranjeWind project[163]. A benefit with floating solar is the possibility of placing these between wind turbines or other floating structures, which improves system utilisation, however floating solar has never been tested at great water depths and in the rough conditions that surrounds the NCS oil and gas assets. Here, mooring to other floating structures would be required. Floating solar has substantially lower CAPEX than offshore wind, but requires either integration with the grid, energy storage or other power sources – as power generation is highly fluctuating.

C.3 Wave power

Wave energy converters convert the kinetic energy of waves into electrical power. The technology is currently undergoing pilot testing at TRL level 6/7[164]. A recent case study[165] found that using wave power for oil and gas platforms would involve less balancing requirements than for offshore wind due to the more consistent nature of waves. For example Ocean Harvesting is planning a full-scale sea trial of their technology in 2024-2026[166]. Limited testing of wave power in rough conditions have been done, which in turn yields a way to go before this technology is likely to be commercially available across multiple sites. Full electrification cannot be done with this technology alone, but requires synergies with other power sources, storage, or grid connection.

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159 https://www.netzerotc.com/news-insights/ceraphi-energy-awarded-funds-to-undertake-pioneering-decarbonisation-study/
160 https://solarduck.tech/merganser-pilot/
161 https://solarduck.tech/teal-pilot/
162 https://www.offshorewind.biz/2024/06/12/vattenfall-cip-to-integrate-large-scale-floating-solar-green-hydrogen-systems-with-new-2-gw-dutch-offshore-wind-farm/
163 https://www.offshorewind.biz/2024/03/04/work-starts-on-worlds-largest-floating-solar-project-part-of-rwes-oranjewind/
164 https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide
165 https://www.offshore-energy.biz/case-study-of-oil-and-gas-platform-electrification-with-wave-energy-delivers-promising-results/
166 https://oceanharvesting.com/our-technology/

C.4 Nuclear power

Onshore large scale nuclear power is a mature and proven technology, which generally is considered safe, and could provide an emission-free replacement of conventional gas turbines. Building a nuclear power plant on shore would also yield a base-load power production that onshore industries could benefit from. There are however some challenges that have caused this option to be excluded for further analysis. Nuclear power is dependent on suppliers of nuclear fuel, nuclear plant developers and storage sites for waste. All of these are currently external to Norway. This technology also has a rather low public acceptance of 51% in a recent survey in Norway (Opinion AS Samfunnsmonitor). Further, CAPEX is very high in Europe, due to low build rate. As Norway has no nuclear power construction capabilities currently, CAPEX is likely to be even higher. OPEX is also likely to be high due to high fuel costs, security, waste treatment, and waste disposal (which is currently not available in Norway). Lastly the construction times are long, and the lifetime are likely to exceed that of the platforms it supplies – which, in the frames of platform electrification, would yield a high levelized cost of energy.

For the less mature Small Modular Reactor (SMR) technology, additional challenges include its low Technology Readiness Level (TRL) and limited experience in Europe, making large-scale deployment unlikely before the 2040s. However, a notable advantage of SMRs is their potential to be placed offshore.

C.5 Water management for high water cut

Managing and reducing high water cut can lower the energy intensity of oil production. Handling, lifting, separating, and disposing of water is energy intensive. Reducing unnecessary water production decreases the energy required per barrel of oil produced, directly lowering emissions. There are various ways in which to do this, with one of the most effective measures being the use of automated inflow control devices/valves. These can reduce the amount of water produced by several 10s of percent (Inflow Control claim 70% reduced water in light oil reservoirs[167]) and are potentially low effort to install as there are many well interventions annually on the Norwegian Continental Shelf which could include these devices[168]. It is worth noting that this technology is aimed at oil production rather than gas.

GHG emission reduction potential is dependent on how much power consumption can be reduced from today's level. Also, the reduction is highly dependent on choice of technology and from case to case. To achieve active implementation of high water cut, there needs to be a focus on reducing power consumption as currently it is cheaper to use more gas lift than to decrease the water cut.

C.6 Water management for stable displacement (w/ or w/o chemicals)

Reducing the produced water during flooding processes can reduce energy requirements for handling the water once it is produced. This requires more efficient displacement of oil which can be achieved by flooding either with or without chemical additives e.g. surfactants. Reducing the amount of injected water through use of these chemicals or a better understanding of the reservoir is also possible. This is highly case specific between reservoirs and would only have a minor effect on emissions if the platform/rig/vessel is still powered using fossil gas and/or diesel.

C.7 Compact top-side CCS

For capturing GHG emissions that are hard to abate through electrification measures, such as from FPSOs or direct-driven equipment, CO_2 capture and storage can be implemented directly at the installation. Compact topside CCS units

[167] https://www.inflowcontrol.no/

[168] https://www.spe-aberdeen.org/uploads/1605_DEVEX-2024-Experience-from-implementation-of-autonomous-inflow-control-AICD-at-the-Troll-field-on-the-Norwegian-continental-shelf-27052024.pdf

capture CO_2 directly from the turbine exhaust. Due to weight and volume constraints on the installations, lighter and smaller units are needed. Developments are progressing and the first commercial products for offshore applications are recently made available on the market, however not implemented[169]. Availability of topside capacity and small CO_2 volumes is a concern.

Existing offshore installations might allow limited weight and volume additions when it comes to including or retrofitting CO_2 capture systems. Floating platforms need special designs to account of motion effects of the CC units. Tailored CO_2 capture systems optimized for offshore applications are being developed, including systems designed for floating applications (i.e. FPSO). Aker Carbon Capture has presented versions of their technology specifically tailored for FPSO applications but can be applied to all offshore installations[170]. 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.

Significant topside capacity is required, likely only being applicable for FPSOs for brownfield installations. With few FPSOs on the NCS, the application scope is limited. The volume of CO_2 captured is up to 4 kt/y for each MWe installed (a 30 MW GT corresponds to up to 120 kt/y captured). For most installations, volumes will be too small to justify the cost of CCS infrastructure.

C.8 Hydrogen and hydrogen-derived fuels for gas turbines

One technical solution for reducing emissions from the gas turbines is by replacing natural gas (fully or partly) with 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) however has not been applied offshore. Firing hydrogen in gas turbines for fully commercial reasons depends on the attractiveness of the various power markets or power needs (island-operation). Note that hydrogen also can be used in combination with other technologies such as offshore wind to provide flexibility and storage. Though none of the fuels emit CO_2, both hydrogen and ammonia combustion with air entails particularly high temperatures compared to fossil fuels, and potential NOx formation, especially in the case of ammonia.

Hydrogen- and ammonia powered turbines are currently only in the demonstration phase, and low-emission hydrogen/ammonia production in Norway is currently scarce, though emerging. The OPEX is expected to be very high for hydrogen and derivatives, not only due to high fuel price, but the need for special carriers, and new base infrastructure. In addition, the use of these fuels is not widely adopted, and safety considerations of using these fuels offshore must be properly understood before applied.

C.9 Heat pumps

Offshore heat pumps are commercially available (for example Kanfa has an offshore offering[171]) and can replace electric heaters and gas-fired boilers. Their use in combination with platform electrification projects results in energy savings and can reduce emissions. The CAPEX is currently high, but the technology is moving fast, and is expected to be scalable by 2030, which will bring costs down.

[169] There is one project due to start operation in 2025 in Angola with carbon capture on part of the flue gas from turbines on the FPSO Agogo. https://www.carboncircle.com/carbon-circle-as-signes-pioneering-epc-contract-for-offshore-carbon-capture

[170] https://akercarboncapture.com/offerings/just-catch-offshore/

[171] https://www.kanfa.energy/carbon-reduction-solutions/

C.10 Reduced flaring

Flaring on the Norwegian continental shelf has been heavily regulated since production started. Flaring is only allowed in connection with safe start-up, shutdown, and pressure blowdown and accounted for 4% of emissions in 2023. With the exploration of new areas and development of new discoveries in the high production scenario there is likely to be some increased flaring as can be seen in the emissions data in the late 1990s and late 2000s – this can be mitigated through implementation of systems for closed flaring with gas recovery. Getting flaring volumes as close to zero as possible will be significant for reaching the final incremental reductions for the 90-95% by 2050 target.

C.11 Rigless P&A (plugging and abandonment) through use of vessels

Some of the well scope is being performed rigless today, however performing tubing removal to facilitate logging operations and barrier placement require more expensive rigs and are not able to be done fully rigless today. There are lighter rigs available today, however they do not fully provide a drastic cost saving advantage due to their current rig rates. Vessels are available and can be converted or built to specification for rigless P&A. There are continued challenges in the main obstacles of tubing removal / through tubing permanent well barrier placement.

Two main obstacles exist to enable rigless P&A by vessels on subsea well and/or using wireline or coiled tubing until on platforms. Firstly, through tubing (dual string) logging technology needs to be fully qualified and industry accepted, which is happening, with solutions nearing the market. Secondly, the ability to set downhole barriers inside of tubing that can create cross-sectional barriers inside or extending outside of the production casing/liner at the cap rock depth. This technology may take 10+ years to develop.

Several companies on the operator and supplier side, both based in Norway and abroad are working on the two main obstacles as well as other options including cheaper rigs (modular drilling/hydraulic workover units) and other technologies. There is a willingness in the industry to invest in these cost saving technologies.

Existing offshore Oil & Gas value chain and supply chain should be available, once technology matures and is ready. Complex solutions to new downhole barrier technology need to be solved as well as assuring the stakeholders that newer, more cost-efficient solutions are robust and can function fully as permanent well barriers.

Well abandonment and offshore decommissioning is funded 78% by the taxpayer/Norwegian government[172]. There is an extremely significant decommissioning liability, which should be optimized to save costs for all stakeholders. Well P&A operations including current and future technology are performed according to regulations and, in general, no significant well leakages/releases are observed. Wells are planned for zero leak for eternity, and risk-based solutions are also implemented as well.

Should the overall P&A scope/time required to plug wells be reduced significantly, there would be many positive consequences in terms of the overall environmental impact from the P&A operations.

Significant R&D costs for technology development in newer rig solutions, logging technology and downhole barrier solutions are ongoing and will continue to be needed. Should the solutions be realized, the operational cost of implementing them would be relatively low, as they can follow conventional oil & gas operational best practice. There is a risk that the technology required is too complex, too arduous, or too difficult to qualify to bring to the market and implement. However, the upside gained in performing rigless P&A is high and can achieve significant cost savings.

C.12 Better modelling for reservoir understanding

Future developments in big data processing, reservoir modelling, and subsurface understanding could lead to improved drilling commercial success rates. This could lead to reduced emissions from drilling, assuming market forces do not

[172] SWIPA - Centre for Subsurface Well Integrity, Plugging and Abandonment

then act to make drilling cheaper and increase the number of wells drilled again. This is not one specific technology and relies on cross-discipline cooperation and improvement.

D More details on CAPEX estimation for gas-fired power plants with CCS

The DNV Capture Cost Database is based on public information on the cost of post-combustion capture facilities. This information is available for a range of scales, flue gas types and regions, and include published reports from capture projects in operation, academic simulation-based estimates and feasibility, pre-FEED or FEED studies for capture on existing assets. As the capital cost estimates were published over a significant period (2008 to 2024) and using different currencies, efforts have been made to convert them to 2024 USD[173].

The key output of our database is the “2024 CAPEX (million USD) per mtpa CO_2” value, which is the capital cost in 2024 USD of a capture plant expressed per mtpa CO_2 capacity. Due to economies of scale, this value is normally expected to be lower for larger capacity plants.

To enable meaningful comparison and trend observation, efforts are made to use a consistent basis for the costs listed in the database. These include total capital costs associated with capture plants, such as materials, construction, labour, and more; total capital costs associated with CO_2 compression or liquefaction units; integration with the host facility; and auxiliary boilers to provide steam to the capture facility. The following are not included: any form of operating cost, transport and storage costs (capital or operating), and net increases to power generation or production capacity, such as additional heat or power generation facilities.

D.1.1 Capture plant sizing

Based on emission factor from the US Department of Energy Cost & Performance baselines, a new gas power plant with net output of 200-250 MWe using state-of-the-art H-Class gas turbines is expected to generate 0.5 – 0.6 mtpa CO_2 with a concentration of ~4.5 vol% CO_2 in the flue gas. Assuming a capture rate target of 95%, the capture plant capacity will be 0.475 – 0.57 mtpa CO_2 captured.

D.1.2 Gas power with carbon capture: CAPEX cost estimates

Eight gas-power CO_2 capture references are available in our database, in the range of 0.16 – 2.61 mtpa CO_2 captured. All reference cases use amine solvent capture systems from various providers. Figure 0-1 illustrates the relationship between capture plant capacity and CAPEX per mtpa capacity, showing limited economies of scale relative to capture applications in other industries. This is likely due to the low CO_2 concentrations in gas power applications, meaning modest reductions in flue-gas handling equipment for incremental CO_2 capture capacity. The high outlier – the cancelled Peterhead capture project, not to be confused with SSE’s ongoing Peterhead 2 capture project – is due to high site integration costs associated with the retrofit of the CO_2 capture system to the existing site. This is not considered representative for a greenfield gas power with CO_2 capture application.

[173] Currency conversion was performed using the average USD exchange rate from the year of publication. Costs are adjusted to 2024 USD based on inflation, as measured by the US Producer Price Index: Machinery and Equipment. No adjustments were made for technology improvements or "learning rate" effects since publication; all near-future deployments are considered to remain in the “first-of-a-kind” phase.

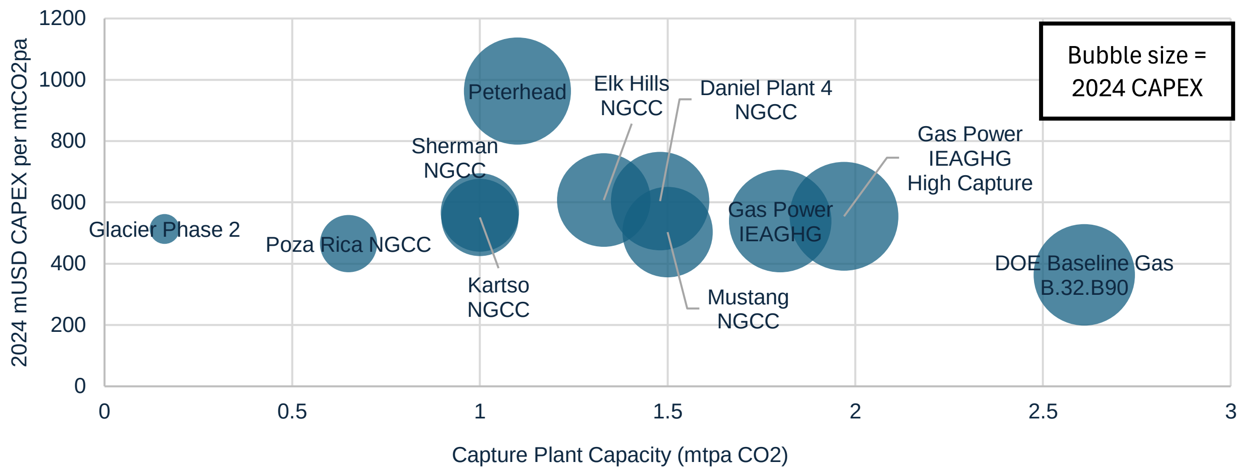


Figure 0-1: Adjusted CAPEX/tonne CO_2 vs. plant size

Based on the relevant reference projects, especially the similarly sized Karstø (Norway), Sherman (USA) and Poza Rica (Mexico) capital cost estimates, a range of **450 – 600 million USD/mtpa** capacity is expected. Figure 0-2 shows the costs by year of study, adjusted to 2024 levels. When the Peterhead outlier is removed, there is no clear cost reduction trend for gas power references over the past 16 years, with recent studies since 2020 all within the 500-600 million USD/mtpa region.

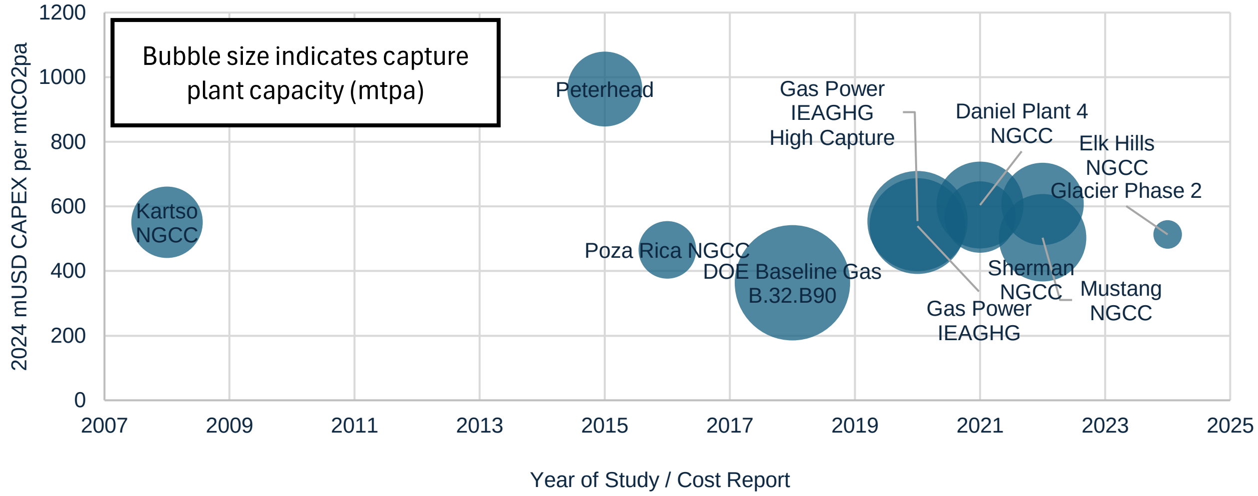


Figure 0-2: Year of study vs CAPEX per mtpa. When the Peterhead outlier is removed, no learning rate is shown over the past 16 years

The facility CAPEX of a new-build combined cycle gas turbine power plant is **not** included in our Capture Cost Database. Instead, the cost of the facility is estimated using the following references:

US Department of Energy Cost & Performance Baselines

- Case B32A – H Class Gas Turbine
  - 962.7 MUSD (2018) for a net power of 992 MWe
  - 1222.6 MUSD (2024) for a net power of 992 MWe

- 1230 USD (2024) per kWe output

US Energy Information Administration

- H Class Turbine (Case 8)
  - 1084 USD (2020) / kWe capacity
  - 1333.3 USD (2024) / kWe capacity

E More details on emerging capture technologies

In this section we will focus mainly on emerging technologies within the **post-combustion** category relevant for the long-term 2050 emissions reduction target. We consider the most promising to be those with a TRL of 5 or higher, as lower TRLs have a lower likelihood for commercialization in the next decade – which is the relevant timeframe if multiple projects are to be realised prior to 2050. Development and commercialization of new capture technology typically requires more than a decade when bringing the technology to market from low maturity levels.

There are many developers working on absorption technologies, some of which use novel materials and others advanced amine-based systems. These technologies are currently at the pilot level and include solutions such as water-lean solvents, rotating packed bed absorbers and desorbers, chilled ammonia, and salt-based solvents. Similarly, new technologies are also appearing in the sorbent space, namely metal organic frameworks (MOFs), microporous sorbent materials, polymeric membranes, and alumina-based capture. Finally, membranes are seen as a key area for development with various types being investigated including nanoporous, hydrophobic, polymeric, amine-doped, and cryogenic membranes.

Advanced solvents rely on chemical absorption of CO_2 in liquid solvents, involving exothermic reactions and temperature swings for stripping/desorption. They have a long history of commercial use with good heat integration, making them effective for capturing CO_2 from low-concentration gas streams. However, their diluted nature, low tolerance to acid gases, and high regeneration energy requirements are significant challenges. They also have high CAPEX requirements. **Research** is focused on developing non-corrosive, high-capacity solvents with improved reaction kinetics and lower regeneration energy, and higher degradation resistance. Promising approaches include water-lean solvents, catalysts, novel solvents that phase-change with CO_2, process intensification, and hybrid systems.

Advanced sorbents work by adsorbing CO_2 onto a solid surface through either chemical or physical interactions. Regeneration is achieved via pressure swings, temperature swings, or a combination. The absence of water reduces sensible heating and stripping energy requirements, and they provide high capacity and fast kinetics allowing capture from low concentration gas streams. The main challenges include durability, maintaining high mass transfer, system design, pressure drops vs reaction rates, and scaling-up. **Research** is focused on developing low-cost, stable sorbents with high CO_2 selectivity and improving process equipment designs.

Advanced membranes use permeable materials to selectively separate CO_2 from flue gases based on physical or chemical interactions, offering simple, compact operations without chemical reactions or moving parts. They have a higher tolerance to acid gases and no steam requirements. Their challenges lie in balancing flux and selectivity, often requiring multiple stages or feed compression. **Research** is directed toward improving membrane durability, permeability, and selectivity, as well as exploring hybrid systems and novel conditions like cryogenic operations.

It is not a straightforward exercise to compare different technologies. The technologies themselves may be fundamentally different, and the environment and system at which the technology is demonstrated may be different. To aid comparison, a benchmark technology is typically defined in combination with a case definition. Such an approach helps assessment of emerging technologies. Chemical absorption by using 30 wt% monoethanolamine (MEA) has historically been used as the benchmark technology for such purposes. In recent years, the Cesar-1 solvent (amine blend of piperazine (PZ) + 2-amino-2-methyl-1-propanol (AMP) at 40 wt%) has been proposed as a new benchmark.

This open solvent shows cost reductions compared to MEA, with the required heat energy for solvent regeneration similar to commercial proprietary solvent systems.

IEAGHG have developed a techno-economic framework and assessment of emerging capture technologies for the power sector – focusing on coal and gas-fired power plants – revisiting the assessment on a 5-yearl basis[174] . IEAGHG emphasizes that costs are typically underestimated for low TRL technologies. Potential issues might not be visible yet because the technology has not yet been exposed to realistic environments. At lower maturity levels, information to support cost estimation with confidence may be missing. As the latest comprehensive techno-economic assessment was published in 2019, the assessment will likely be revisited and republished this year.

F A short introduction to carbon markets

In this chapter, we aim to give a brief introduction to carbon markets and the difference between compliant and voluntary markets, the different types of carbon credits, and best practices for using carbon credits to offset emissions.

F.1 What are carbon markets?

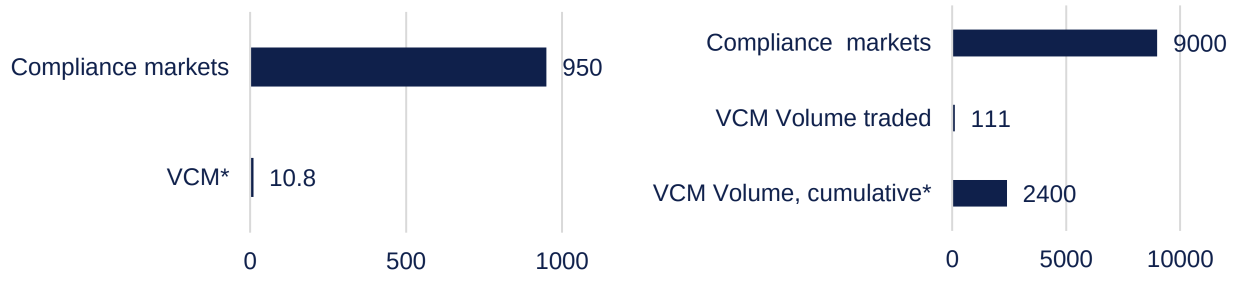
Economists call carbon emissions a "*negative externality*", as they impose costs on society (such as environmental damage) which are not reflected in the market prices of the goods and services that produce those emissions. This leads to a market failure, where too high emissions are generated because the true societal cost is not considered. The solution to this market failure is to internalise the externality by implementing carbon pricing, through mechanisms such as carbon taxes or cap-and-trade systems, incentivising reductions in emissions by making polluters bear the full cost of their activities. These mechanisms are implemented in **carbon markets**, and we can distinguish between two types: **compliance markets** and **voluntary markets**.

- **Compliance carbon markets** are government-regulated systems, like the EU ETS, where companies must buy and trade allowances (or permits) to emit CO_2. These markets are mandatory for industries subject to emissions caps and are designed to meet national or international climate goals.
- **Voluntary carbon markets** operate outside legal requirements, allowing companies or individuals to purchase carbon credits to offset their emissions voluntarily[175]. These credits typically come from projects that reduce, avoid, or remove carbon emissions, and are created when an entity under-utilises their right to emit or creates an opportunity to capture carbon. There is not one centralised "market" where credits are traded at a unified price such as the EU ETS – most of the credits are verified and sold "over the counter" through registries, such as through Verra (the Verified Carbon Standard). Voluntary carbon credits are used for corporate responsibility or to meet voluntary climate commitments, not regulatory obligations.

While the size of the VCM has grown significantly over the past years, both in terms of value and volume of traded carbon credits, it is dwarfed by compliance markets as seen in Figure 0-3: the cumulative value of all carbon credits traded on the VCM from pre-2005 to 2023 is around 1% of the 2023 value traded on compliance markets.

[174] https://ieaghg.org/publications/further-assessment-of-emerging-CO_2-capture-technologies/

[175] Historically, there were other voluntary crediting mechanisms as well, such as international crediting mechanisms and regional, national, and supranational crediting mechanisms. However, especially the international crediting mechanisms, such as the Clean Development Mechanism and the Joint Implementation Mechanism which have been created under the UN Kyoto Protocol, have been discontinued. More information on this can be found in Appendix A.



*Cumulative number, 2023 value is 0.7 billion USD

*Cumulative number includes volumes from pre-2005 to 2023

Figure 0-3: Comparison of value (billion USD) and volume (million tonnes CO_2) of traded credits/allowances in 2023 on compliance markets and the VCM[176]

F.2 What are carbon credits?

Not all carbon credits are created equal. There are three main types of carbon credits traded on VCMs, depending on whether the project it comes from is avoiding, reducing, or removing emissions:

- **Carbon avoidance** projects relate to an action that prevents a carbon-emitting activity from happening. An example of avoiding emissions would be a new renewable energy project which would generate electricity instead of building a new fossil-fuelled generator or a project avoiding deforestation which would result in the release of CO_2 into the atmosphere. They are based on the emissions that might have existed had a project not been funded. However, setting this baseline is challenging, since the baseline is not observable. Therefore, there is a high risk of over-crediting.[177]
- **Carbon reduction** projects relate to an action that decreases the amount of greenhouse gas emissions, compared to prior practices. Examples of carbon reduction credits are reducing methane generation by converting a landfill gas into a fuel used for combustion or reducing fossil fuel use by improving fuel efficiency. These reduction credits are measured against a baseline of emissions of the existing technology or process. Setting the baseline of emissions that would have happened in the absence of the carbon reduction project can be challenging since this baseline is not observed. Moreover, there is an incentive to set a pessimistic baseline to maximize the reduction credits claimed. This might lead to over-crediting.[178]
- **Carbon removal** projects (also known as Carbon Dioxide Removals, CDRs) involves the process of removing CO_2 from the atmosphere and permanently storing it. These projects can either be nature-based or technology based:
    - **Nature-based carbon removal** involves conserving, restoring, or better managing ecosystems to remove CO_2 from the atmosphere. Examples encompass afforestation, the restoration of coastal wetlands, and switching to restorative agricultural practices. These ecosystems then capture CO_2 from the air and sequester it in plants, soils, or sediments.
    - **Technological carbon removal** would encompass using technology, such as DAC to remove CO_2 from its natural cycle and permanently store it in geological storage.

Carbon removal credits are considered "best in class" as they directly remove CO_2 from the atmosphere and provide long-term or permanent storage solutions. However, there are differences within them:

[176] Sources: Ecosystem Marketplace (2024): State of the Voluntary Carbon Market, carboncredits.com, World Bank Group (2024): State and trends of carbon pricing
[177] https://www.carbon-direct.com/insights/how-do-carbon-credits-actually-work-removal-reduction-and-avoidance-credits-explained
[178] https://link.springer.com/article/10.1007/s10584-010-9802-0; https://www.researchsquare.com/article/rs-2606020/v1

- **Durability:** Carbon stored in biological carbon sinks can re-enter the atmosphere through deliberate action, such as deforestation or the ceasing of restorative agricultural practices, or through accidents, such as wildfires. This makes them less durable. Technological removals, in contrast, can offer high durability, being able to store CO_2 for hundreds of years.
- **Baselining:** For technological removals, where the baseline is zero, determining baselines for nature-based removals can be more challenging as one needs to measure or estimate a non-zero baseline for natural carbon removal. Moreover, measuring creditable removals are more challenging to determine since (net) changes in the carbon stock need to be measured or approximated over time.

To obtain a carbon credit, a project needs to fulfil certain criteria, such as additionality, permanence, and a third-party validated methodology for baseline and emissions reduction/removal/avoidance calculation. After implementation, the greenhouse gas mitigation needs to be verified by another audit process. One of the independent crediting mechanisms, such as the Gold Standard or the Verified Carbon Standard, can then register the carbon mitigation and issue a carbon credit.

In contrast to carbon allowances traded under EU ETS, where each allowance has a unified price, prices for carbon credits on the VCM can differ widely depending on the type of credit (whether CO_2 is avoided, reduced, or removed), the location and size of the project they are derived from, whether these projects provide social and environmental co-benefits, and whether the credits are directly sold to buyers or through intermediaries. Figure **0-4** displays average VCM transaction prices from 2022 and 2023 by project category (not including carbon removals), while Figure **0-5** shows share of credits per credit type in the same period. According to Ecosystem Marketplace[179], projects with reported co-benefits are priced higher than those without, and credits from carbon removal projects typically have a +200% premium, although the price is highly variable depending on the type of removal project with durable, technology removals seeing significantly higher prices. For volumes traded of carbon removal credits, nature-based credits currently make up over 99% of the carbon removal credits traded[180]. Nevertheless, Carbon Direct notes that the demand for high-quality, durable carbon removal credits is rising, although a majority of these credits are still in development and limited in number. [181]

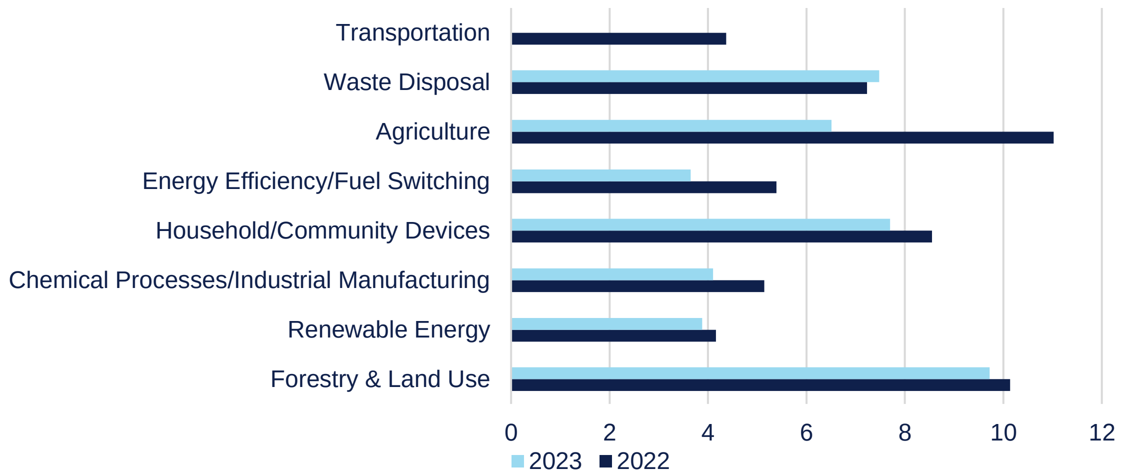


Figure 0-4: VCM transaction prices by project category, 2022 and 2023, in USD/ton CO_2eq[182]

[179] Ecosystem Marketplace (2024): State of the Voluntary Carbon Market
[180] https://www.carbon-direct.com/insights/how-do-carbon-credits-actually-work-removal-reduction-and-avoidance-credits-explained
[181] Carbon Direct (2023) : State of the Voluntary Carbon Market
[182] Ecosystem Marketplace (2024): State of the Voluntary Carbon Market

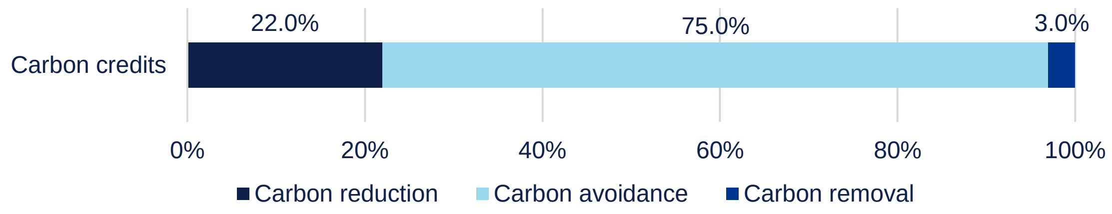


Figure 0-5: Shares of carbon reduction, carbon avoidance, and carbon removal projects in carbon credits traded on VCMs in 2022 and first half of 2023[183]

F.3 Issues related to carbon credits

Carbon credits and offset projects have faced increasing criticism in recent years, with some described as "junk" [184] despite the standards upheld by registries in the VCMs. This is due to several key issues:

- **Over-crediting:** Measuring baseline emissions is challenging, often leading to inflated claims of emissions avoided or reduced. Research shows that forest protection schemes (so called REDD+[185]) often overestimate how much deforestation has been prevented and hence overestimate the emissions they have been able to offset.
- **Durability:** Some projects, such as forest protection, lack permanence (durability) due to risks like wildfires, political shifts, or deforestation moving to unprotected areas (known as leakage, where deforesters log another area of forest which is not under protection).
- **Additionality:** Many projects, especially renewable energy projects today, would likely have happened without carbon credit funding, undermining the true impact of credits.
- **Greenwashing:** Companies often claim climate neutrality through offsets, although these projects don't lead to real emissions reductions – they are only compensating for emissions elsewhere.
- **Double counting:** Emissions reductions are sometimes counted by both the project country and the company purchasing the credits towards their climate targets, creating a misleading picture of the actual impact.
- **Negative local impacts:** Offset projects can negatively affect local communities, as investigations into offsets issued under the Clean Development Mechanism have revealed[186].

A 2023 report from Carbon Direct found that fewer than 10% of offsetting projects met quality standards[187], with carbon reduction and avoidance projects – particularly forest schemes – most prone to these risks[188]. Despite this, many large companies, including Shell, Volkswagen, and AUDI, continue to buy carbon credits[189].

However, the use of offsets is increasingly scrutinized, with lawsuits emerging over greenwashing claims: according to the *"Global trends in climate change litigation"* report, more than 25 lawsuits were filed over misleading claims in 2021

183 Carbon-direct.com
184 https://www.theguardian.com/environment/2023/sep/19/do-carbon-credit-reduce-emissions-greenhouse-gases
185 'REDD' stands for 'Reducing emissions from deforestation and forest degradation in developing countries. The '+' stands for additional forest-related activities that protect the climate, namely sustainable management of forests and the conservation and enhancement of forest carbon stocks.
186 https://carbonmarketwatch.org/wp-content/uploads/2018/10/CMW-THE-CLEAN-DEVELOPMENT-MECHANISM-LOCAL-IMPACTS-OF-A-GLOBAL-SYSTEM-FINAL-SPREAD-WEB.pdf
187 Carbon Direct (2023): State of the Voluntary Carbon Market.
188 https://www.carbon-direct.com/insights/assessing-the-state-of-the-voluntary-carbon-market-in-2022
189 https://interactive.carbonbrief.org/carbon-offsets-2023/

and in 2022 respectively[190]. Moreover, using offsets to claim scope 1 emission reductions is not in line with industry best practices, as explained in Chapter 7.1.3.

The future of voluntary carbon markets hinges on restoring trust in credit quality, after several companies have abandoned offsets for fear of reputational risks. As an example, Shell has now joined companies like Nestle, Gucci and Leon in moving away from carbon offsets[191], despite being the largest player in carbon credit purchasing last year with announced investments of around USD 100 million per year on offsets by 2030[192]. If confidence is regained, BloombergNEF predicts rising demand and prices for carbon credits, potentially reaching USD 170-200/ton by 2050[193], driven by initiatives like the Integrity Council on Voluntary Carbon Markets[194] setting global standards for VCMs, and the European Carbon Removal Certification Framework (CRCF).

G More details on frameworks of climate targets relevant for Norway

G.1 Article 6 of the Paris Agreement

Article 6 of the Paris Agreement allows countries to voluntarily cooperate with each other to achieve emission reduction targets set out in their NDCs. It allows transfer of carbon credits generated in one country to help other countries meet its climate targets. To ensure that only one country counts the emission reduction toward its NDC, a mechanism for “corresponding adjustment” (CA) has been established: when Parties transfer a mitigation outcome internationally to be counted toward another Party’s mitigation pledge, this mitigation outcome must be “un-counted” by the Party that agreed to transfer it.

Article 6.1 emphasizes the importance of ‘voluntary cooperation’ in countries implementing their NDCs to allow for ‘higher ambition in their mitigation and adaptation actions, and to promote sustainable development and environmental integrity’.

Article 6.2 sets out guidelines covering internationally transferred mitigation outcomes (ITMOs) between two governments that are parties to the Paris Agreement. It hence establishes a cooperative approach in the form of bottom-up bilateral or multilateral agreements. ITMOs can be transferred from the credit-generating, so called host country, and (i) transferred to credit-buying countries towards achieving their NDCs, (ii) used in market-based schemes, such as the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) (referred to as ‘other international mitigation purposes’, and (iii) used by companies to offset their emissions (‘other purposes’). The host country needs to authorize the use of ITMOs for the various purpose and apply CAs if mitigation outcomes are exported to help other countries with their NDCs.

Article 6.4 establishes a new centralized crediting mechanism, resembling the function of the former Clean Development Mechanism, for trading in GHG emissions reductions between countries under the supervision of the Conference of Parities, the decision-making body of the UNFCCC. It will approve methodologies, set guidance, and implement procedures, such that Emission Reductions (ERs) are generated of assured quality and environmental benefits. Projects will need to be registered with the Supervisory Board and project activity will need to receive host country approval for Article 6 transactions. Article 6.4 basically establishes a centralized, UN-run carbon credit registry or carbon market.

Carbon markets come in two forms. In *compliance markets*, where regulated entities obtain and surrender emission permits or offsets to comply with imposed regulation. The EU ETS could be interpreted as a multilateral mechanism under Article 6.2 of the Paris Agreement, based on voluntary cooperation of the EU/EEA countries to achieve their mitigation outcomes. On the *VCM*, in contrast, carbon offsets are not purchased to be used in a regulated market, but

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190 https://www.lse.ac.uk/granthaminstitute/wp-content/uploads/2023/06/Global_trends_in_climate_change_litigation_2023_snapshot.pdf

191 https://www.esgtoday.com/nestle-moves-away-from-carbon-offsets-to-focus-on-emissions-reductions-across-brands/

192 https://www.reuters.com/sustainability/climate-energy/shell-has-given-up-specific-targets-carbon-offsets-ceo-2023-10-17/; https://www.theguardian.com/environment/2023/sep/08/shell-signals-retreat-from-carbon-offsetting

193 https://about.bnef.com/blog/carbon-credits-face-biggest-test-yet-could-reach-238-ton-in-2050-according-to-bloombergnef-report/#:~:text=2024%20is%20set%20to%20be,%241.1%20trillion%20annually%20by%202050.

194 https://icvcm.org/about-us/

rather to re-sell, retire or meet environmental claims or targets. Carbon credits traded on the VCM are used in non-compliance markets by the private sector. The underlying mitigation outcomes are typically not required to be authorized as CAs by the host country, leading to double counting towards the host country's NDC and the private buyers' climate target. Climate offsets on the VCM cannot be equated with ITMOs regulated by Article 6 of the Paris Agreement.

G.2 EU climate policies and the CRCF

In 2020, the EU set an updated climate target for 2030 of a net domestic reduction of at least 55% in greenhouse gas emissions by 2030 compared to 1990. In 2021, the EU published a Regulation setting out a binding objective of climate neutrality in the EU by 2050 at the latest, aiming to achieve negative emissions thereafter. This legal framework for achieving climate neutrality is known as the European Climate Law.[195] It confirmed the 2030 climate target of 55% greenhouse gas reductions, setting it as a legally binding target. This was part of the Green Deal to set the EU on a path to a green transition.

Under the EU legislation, emission reduction targets are covered by the EU ETS, the Effort Sharing Regulation (ESR), and the regulation on land-use related emissions and removals (LULUCF).

Participants in the EU ETS were allowed to use international credits from the Clean Development Mechanism[196] and the Joint Implementation[197] mechanism, two instruments established by the Kyoto Protocol for issuing foreign emission reduction certificates, until 2020, subject to qualitative and quantitative restrictions. However, there is no possibility of using international credits or other carbon offsets for EU ETS compliance after 2020.

The revised ESR sets individual binding reduction targets for Member States for GHG emissions not covered by the existing EU ETS, i.e., domestic transport, buildings, agriculture, waste, and small industries with an EU-level GHG reduction target of 40% by 2030 compared to 2005.

The LULUCF regulation introduces targets for net carbon removal in the land sector for Member States, aiming to increase the EU's net removals by 15%, reaching net greenhouse gas removals of 310 million tonnes of CO_2eq by 2030 in the sector.

In addition, the "Fit-for-55" legislative package revises climate-, energy- and transport-related legislation to align EU laws with the updated climate goals.

The EU Green Deal and corresponding legislation packages did not focus on carbon dioxide removal (CDR). However, CDR technologies are considered necessary for the EU in achieving its net-zero climate targets and net negative emissions after 2050. In the first half of 2024, the EU reached a provisional deal on the Carbon Removal Certification Framework (CRCF), a unified but voluntary certification scheme, which should "enhance the environmental integrity and transparency of permanent carbon removals, carbon farming and carbon storage in products and promote trust in their certification while reducing the associated administrative costs". The agreement sets rules for (i) carbon farming, such as restoring forests and soils, rewetting of peatlands, efficient use of fertilizers and innovative farming practices, (ii) industrial carbon removals, such as BECCS or DAC, and (iii) binding carbon in long-lasting products and materials. The CRCF aims to standardize carbon removal efforts for the EU, given the currently fragmented certification landscape for CDRs and other carbon offsets. It aims to establish EU quality criteria and outline EU monitoring and reporting processes.[198] The implementation of the CRCF should include the adoption of EU certification methodologies for different carbon removal activities through delegated acts, rules for third-party verification requirements and the recognition of certification schemes as aligned with CRCF rules. It is important to note that the CRCF does not include any activities related to carbon removal or avoidance, such as renewable energy projects or prevention of deforestation. In addition, only activities taking place in the EU will be eligible for certification. All certified activities "should contribute

[195] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32021R1119
[196] https://cdm.unfccc.int/
[197] http://unfccc.int/kyoto_protocol/mechanisms/joint_implementation/items/1674.php
[198] https://www.europarl.europa.eu/meetdocs/2014_2019/plmrep/COMMITTEES/ENVI/DV/2024/03-11/Item9-Provisionalagreement-CFCR_2022-0394COD_EN.pdf

to the achievement of the Union's NDC and its climate objectives" and can therefore not be contribute to third party NDCs or compliance schemes.[199] Also the impact of CRCF on the VCM cannot be appraised yet.

[199] https://www.europarl.europa.eu/meetdocs/2014_2019/plmrep/COMMITTEES/ENVI/DV/2024/03-11/Item9-Provisionalagreement-CFCR_2022-0394COD_EN.pdf

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