Wood Mackenzie

Impact of Dual CO_2 Policy on the Norwegian Oil & Gas Sector

November 2026

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About Wood Mackenzie Consulting

Wood Mackenzie is the global leader in analytics, insights and proprietary data across the entire energy and natural resources landscape. For over 50 years our work has guided the decisions of the world's most influential energy producers, utilities companies, financial institutions and governments. As the trusted source of commercial intelligence in the industry, we empower clients to make better strategic decisions by arming them with independent and objective analysis. Wood Mackenzie's consulting teams provide bespoke advisory services leveraging the expertise, data and models of Wood Mackenzie's broader research business.

1 Executive Summary

1.1 Background and context

Wood Mackenzie conducted a scenario-based analysis to assess the potential impacts of CO2 taxes in addition to the EU Emissions Trading System (EU ETS) on Norway's oil and gas sector. Specifically, it evaluates the implications for future supply from the Norwegian Continental Shelf (NCS), the net present value of oil and gas production, associated emissions, and the sector's net contribution to the state. Understanding these effects is essential for the Norwegian Ministry of Energy as it seeks to ensure the long-term, profitable development of national petroleum resources and to maintain an incentive structure that supports emission reduction targets/ambitions and alignment between industry and the state as resource owner.

The scenario analysis also assesses the impact of CO_2 taxes on the economic viability of electrified, partially electrified and non-electrified projects, and, for pre-FID projects and yet-to-find (YTF) prospects, the impact of CO_2 taxes on their 'investability'[1]. In addition, it evaluates the financial implications of potential early cessations across the NCS, the associated production-emissions outcomes under each scenario, and the resulting net income to the state.

This analysis has been conducted by a team drawing on Wood Mackenzie's extensive expertise, proprietary data, and sector-wide analytical capabilities, supported by specialists in upstream NCS activity and carbon policy. Engagement with oil and gas companies operating on the NCS has also helped perform a quality check of assumptions and results. The findings contained in this report reflect Wood Mackenzie's experience in advising governments, regulators, and industry stakeholders on asset valuation, fiscal frameworks, carbon markets, pricing, and scenario development.

Two key scenarios have been considered:

- **Low Case:** ETS only (NOK 872 by 2030, NOK 945 by 2035 and NOK 1,204 by 2050 in real 2026 terms). This scenario assesses the implications for Norway's oil and gas sector if the CO2 tax were removed, leaving only ETS prices in place.

- **High Case:** ETS + Increased CO2 Tax (NOK 2,621 by 2030, NOK 3,500 by 2035 and NOK 6,138 by 2050 in real 2026 terms). This scenario evaluates the impacts of a higher CO2 tax trajectory on upstream activity, asset value and emissions across the sector.

The results focus on the analysis and comparison of the low- and high-case scenarios, with the aim of illustrating the impacts of highly divergent carbon policy scenarios on the future of the NCS.

It must be noted that these results are based on Wood Mackenzie's current outlook for prices, costs, production and resource volumes, including yet-to-find potential, IOGR and the timing of resource development (as shown in Section 2) and could change materially under alternative assumptions for any of these inputs. The valuation figures shown in this report are also sensitive to the discount rate used. Wood Mackenzie's standard discount rate is 10%. We have provided aggregate valuation figures using a 5% discount rate in Appendix F, consistent with the rate typically applied by the Norwegian Ministry of Energy for internal analysis.

The report is structured into four main sections following the executive summary:

1. Section 2 provides Wood Mackenzie's current outlook for Norwegian oil and gas production and emissions from upstream oil and gas operations, which form the basis of the analysis done in this study. The scenario results throughout this report are therefore conditional on this outlook and on Wood Mackenzie's associated assumptions for prices, costs, resource volumes and the timing of resource development, and could differ materially under alternative assumptions. The results of the scenario analysis are presented in Sections 3, 4 and 5.

2. Section 3 examines the impact of high and low carbon pricing scenarios on discovered fields which are classified as On production, Approved for Development, Justified for Development or Economically Viable under the Petroleum Resources Management System (PRMS) classification system.

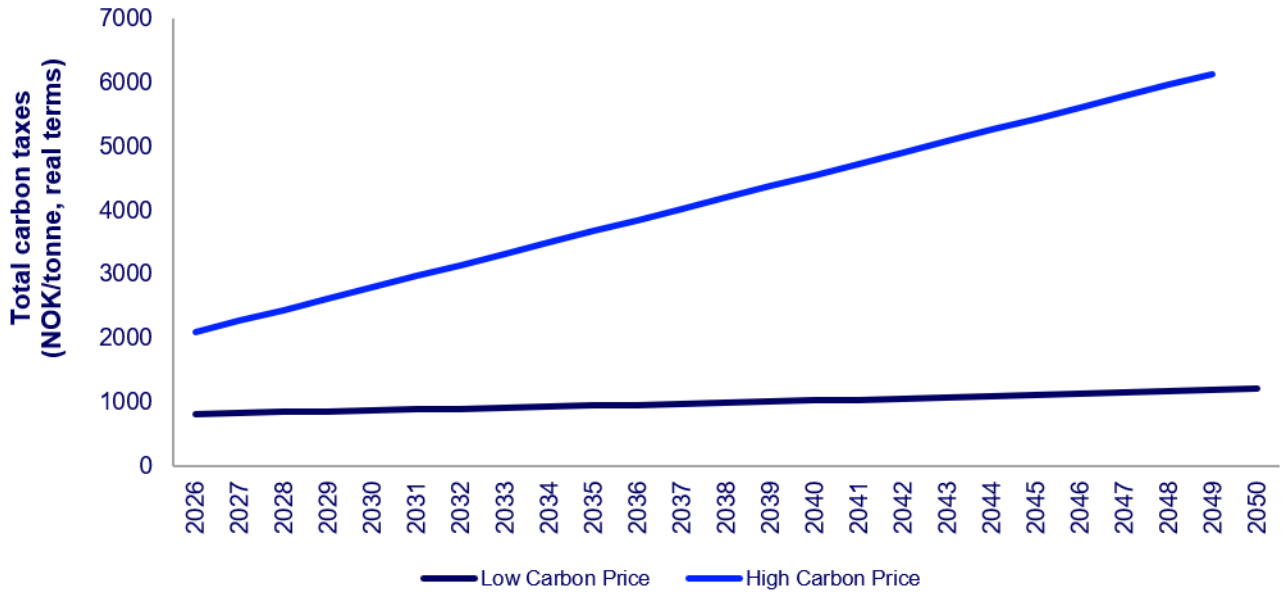
3. Section 4 looks at the impact of the carbon pricing scenarios on new resources including YTF and improved oil and gas recovery (IOGR). This section also looks at the impact of high carbon pricing on the exploration outlook

[1] *For the purpose of this study, a pre-FID asset or the yet-to-find prospect is defined as investable if it achieves a minimum IRR of 15%*

for Norway.

4. Section 5 illustrates the impact of high and low carbon pricing on existing infrastructure and project economics via selected case studies.

Figure 1.1 Low and high carbon tax scenarios used to model the impact on the NCS



Source: Norway Ministry of Energy. Real costs in 2026 terms.

1.2 Key findings of the study

The findings of this study rest on a bottom-up remodelling of Wood Mackenzie's 164 commercial and economically viable field models[2] and 179 yet-to-find (YTF) prospects on the NCS, using the carbon-price scenarios provided by the Ministry of Energy. Every asset and prospect was re-evaluated under the low and high case scenarios. Comparing these two extremes isolates the effect of CO_2 tax policy on production, value, state revenue and emissions. The key impacts[3] of the high case CO_2 tax are summarised below:

- Around 490 million boe of commercial and economically viable reserves (2.8%) become uneconomic, between 600 and 850 million boe of yet-to-find resources (12-19% of investable volumes) are not developed, and an indicative 420 to 640 million boe of improved-recovery upside is lost.

- On a pre-tax[4] basis, US$2.9 billion (NOK 28.0 billion[5]) or 0.7% of value (NPV10) is lost from commercial fields, US$2.5-4.0 billion (NOK 24-37.6 billion) from the yet-to-find portfolio (a 9-14% fall) and around US$1.8-2.9 billion (NOK 17.4-28.0 billion) from improved-recovery upside.

- Government tax revenue (NPV10) from commercial and economically viable fields falls by US$13.2 billion (NOK 127.6 billion) (3.8%), although higher CO_2 tax receipts leave total government take broadly flat. Total government take declines by US$1.8-3.0 billion (NOK 17.8-29 billion) (8-13%) from yet-to-find resources and by US$1.2-2.6 billion (NOK 11.7-26 billion) (7-15%) from improved-recovery projects.

- Cumulative emissions to 2050 are around 3.2% (3.6 MtCO2e) lower for commercial and economically viable fields, and 9-10% (12.2-14.1 MtCO2e) lower once yet-to-find resources are included, driven largely by earlier field and hub closures rather than by decarbonisation initiatives.

The analysis indicates that there is a limited impact of the high CO_2 tax on the production and reserves of commercial and economically viable fields. For these fields, the higher CO_2 tax reduces NPV without materially affecting near-term production. Because carbon costs are deductible at Norway's 78% marginal tax rate, the government effectively covers around 78% (and more via the State's Direct Financial Interest (SDFI) stake) of the carbon taxes through forgone tax revenue. The impact is concentrated in non-electrified fields (for example Statfjord loses around 13% of its pre-tax value, compared with 0.1% for partially electrified Troll).

For commercial and economically viable fields, higher carbon costs bring forward the average cessation of production by around 2 years and cause 15 fields to shut in 5 to 16 years earlier, as compared to the low case. This results in a reduction of produced reserves by ~490 million boe (2.8%). Government take (from profit-based taxes, CO_2 tax and SDFI stake) from the commercial fields nevertheless remains broadly flat (+0.1%), as CO_2 tax receipts almost exactly offset forgone profit-based taxes. The impact on pre-FID fields is limited, largely because these projects are expected to be developed in the near term and are expected to come online and reach plateau production relatively quickly; much of their value is realised before the effects of higher taxes become significant.

In contrast, the YTF prospective resources see a much bigger impact of a higher CO_2 tax. Because the development decision is still open, a high CO_2 tax reduces the commercial attractiveness of smaller discoveries, preventing them from being developed. YTF volumes (expected to achieve a minimum IRR of 15%) fall from 4.6-4.7 billion boe to 3.7-4.2 billion boe as marginal prospects drop below the threshold; more than half of the investable prospects below 20 mmboe drop out (from 30 down to 14). Prospects tied to non-electrified hubs lose 16-22% of resources and 10-15% of pre-tax value, while those tied to fully electrified hubs are largely insulated (4-6% and 4%, respectively). The range of results for the YTF volumes signifies the knock-on impacts as fewer tie-backs increase the share of CO_2 for the other fields tied into the hub and reduce any future possibility for extending and electrifying host hubs. Additionally, the minimum economic field size increases, and exploration activity falls, echoing the decline observed on the UK Continental Shelf as a result of a higher tax burden.

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[2] Commercial fields include producing fields and fields approved for development and classified as justified for development. Further details are available in Appendix C.

[3] As mentioned in this document elsewhere, the quantitative analysis undertaken as part of this study excludes any contingent fields which are not considered economically viable under our current price projections. As per Wood Mackenzie's exploration outlook for Norway, new discoveries are expected to be developed via sub-sea tiebacks to existing hubs. As such the analysis excludes the impact on potential standalone discoveries. The new discoveries are assumed to be on active and inactive acreage in open areas on the NCS. Wood Mackenzie has made no assumption about parts of the NCS that could be opened to exploration in the future.

[4] Throughout this report, NPV10 represents the nominal PV (either pre- or post-tax) calculated using a 10% discount rate discounted to 1 January 2026. The pre-tax value is calculated before deducting profit-based taxes (corporate income tax and special tax) and adding back the CO_2 tax paid (CO_2 tax is treated as an operating cost).

[5] Using an average conversion rate of 9.60 NOK/USD.

The impact on Norway's total production is felt more prominently over the longer term. Combined output in the high-case is effectively unchanged through the early 2030s, runs 3-4% below the low-case by 2035, and the gap widens to 11-13% by 2040 and 14-18% (155-200 kboe/d) by 2045 as undeveloped YTF volumes fail to replace declining commercial fields. The higher tax, therefore, acts less as a uniform cut to output and more as a progressive thinning of the resources that would replace today's producing fields.

Emission reductions are real but stem primarily from non-development, not decarbonisation. The effect is modest for producing commercial fields, where output is largely unchanged before the mid-2030s, and grows materially once undeveloped yet-to-find volumes are taken into account. The high tax is unlikely to incentivise costly emission reduction measures like power from shore, carbon capture or offshore wind: projects face prohibitive capital costs for electrification (Halten, Tampen and Balder/Grane were cancelled in 2025-2026), and operators are more likely to absorb the tax and cease production earlier than to invest in abatement. The high case, therefore, cuts emissions primarily by leaving resources in the ground and closing hubs earlier.

The results identify the point at which a rising CO_2 tax ceases to function primarily as an emissions instrument and becomes a fiscal drag on resource maximisation. For the commercial and economically viable assets, the effect is limited before the mid-2030s. For future resources it becomes an increasingly important factor in determining whether exploration, development and hub life-extension investment happens at all. In the short term there will be some gains in state income from commercial fields, but in the longer term, significant resources are not produced as fields cease early, and YTF prospects remain undeveloped.

2 Base Case view of Norway's Oil & Gas production including ETS and CO_2 tax (2026-2050)

2.1 Production

Norway is Europe's largest oil and gas producer and a key gas supplier to the region. Liquid production has held steady at around 2 million b/d since 2020 and is expected to remain at this level through 2027, after which we anticipate a sustained long-term decline. Gas output reached a record high in 2024, exceeding 12.3 bcf/d, as operators maximised exports to continental Europe and the UK. With relatively modest domestic consumption, nearly all of Norway's oil and gas production is exported. The rate of expected decline will be determined by the pace and scale of new developments and improved recovery.

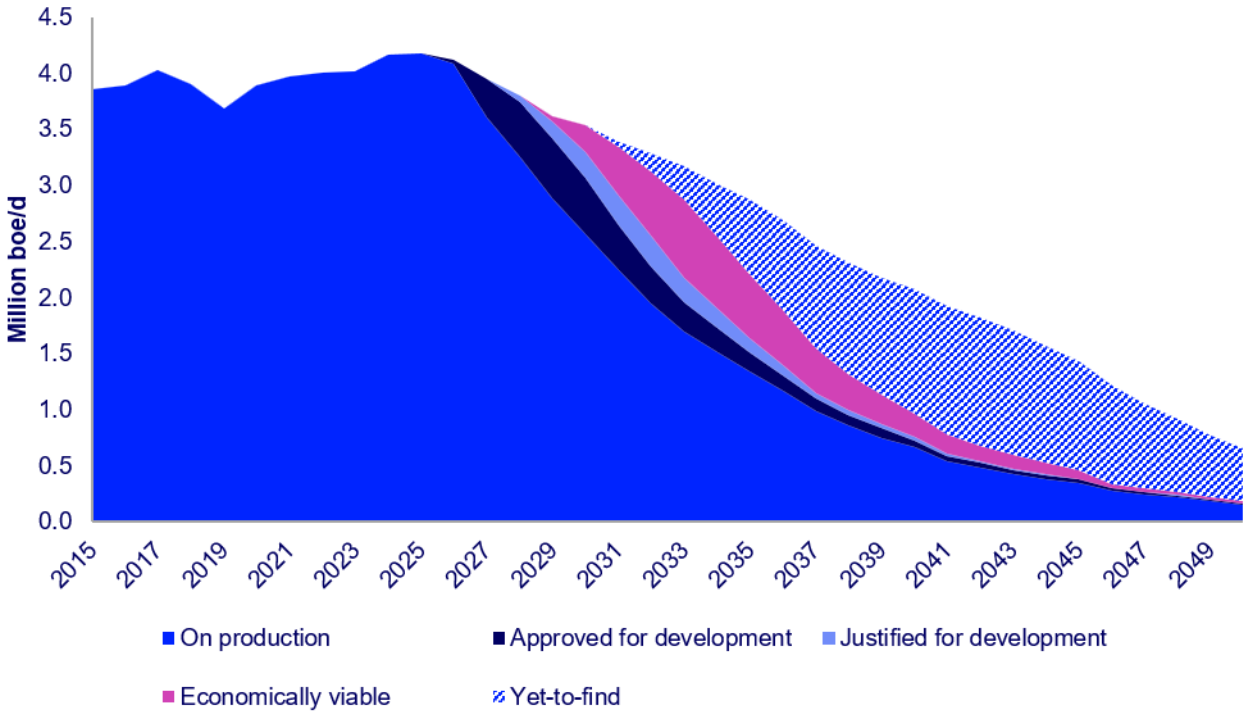
Since the 1990s, Norway has maintained production above 3 million barrels of oil equivalent per day (mmboe/d), reflecting a stable fiscal framework and a regime supportive of oil and gas development. Production peaked in 2004 before entering a period of decline; however, output on the NCS has remained broadly flat at around 4 mmboe/d since 2010. This plateau has been underpinned by reserve growth and new discoveries – notably Johan Sverdrup, which has been critical in sustaining oil supply – while declining liquids production has been offset by growing gas output. As a comparison, the UK's output has fallen by 70% in the same timeframe due to fiscal instability reducing investor appetite.

Looking ahead, the Norwegian government is seeking to mitigate production declines expected in the 2030s and has resisted committing to a phase-out of oil and gas exploration, with an active licensing regime and regular licence rounds. Equinor (which is partly state owned) plays a central role in this strategy, focusing on near-field exploration, subsea tie-backs and measures to extend the productive life of existing assets. The major operators on the Norwegian continental shelf – Equinor, Aker BP, and Vår Energi – have set ambitious long-term production goals, supported by plans for increased exploration drilling, incremental oil and gas recovery (IOGR[6]) activity, faster development of existing discoveries and closer collaboration. These targets are strategically designed to counteract the expected production declines in the 2030s, demonstrating a proactive approach to sustaining Norway's energy output.

Based on current projections, Norway is well-positioned to maintain production above 3.5 million barrels of oil equivalent per day until 2030 as shown in Figure 2.1. However, it is important to note that beyond this point, improved recovery, development of existing fields and further exploration will be crucial to offset the expected declines from the existing fields. In this study, the results of the static effects of carbon tax are shown in Section 3, covering the "on production", "approved for development", "justified for development" and "economically viable" tranches. The dynamic effects of the carbon tax are considered in Section 4, where we evaluate the impact of the carbon tax on Norway's "yet-to-find"[7] volumes shown below.

[6] *IOGR is the additional hydrocarbons recovered from an existing field beyond the original recovery expectation, achieved through improved reservoir management, additional drilling, EOR techniques or late-life asset optimisation.*
[7] *Yet-to-find (YTF) - Recoverable reserves of oil and/or gas which have yet to be discovered.*

Figure 2.1 Total production by status, million boe/d



Source: Wood Mackenzie (Data cut taken in April 2026)

2.2 Resources and corporate overview

Norway's remaining reserves are estimated at 23.3 billion boe as shown in Figure 2.3. In addition, yet-to-find discoveries represent potential upside. The Norwegian shelf is split into three distinct producing areas; the North Sea, Mid-Norway (Norwegian Sea) and the Barents Sea:

- The Central and Northern North Sea is a mature producing region but holds about 70% of Norway's remaining reserves, with the Troll field accounting for roughly one-third of the total. Despite ageing infrastructure, the area continues to draw significant exploration and development activity across most key hubs. Johan Sverdrup, which started producing in 2019, reached peak annual output in 2023 after phase two came online. Aker BP's 680 mmboe Yggdrasil project is the largest development underway and will introduce new infrastructure to the region that could unlock further upside.

- The Norwegian Sea hosts major developments such as Ormen Lange, Åsgard and Skarv, and contains around 20% of Norway's remaining – mostly gas-prone – reserves. The eastern area consists of frontier acreage, with water depths over 2,000 metres, while recent activity has centred around Skarv and Haltenbanken. The 2018 Polarled pipeline connected Aasta Hansteen to Nyhamna, creating a hub for new gas projects like Irpa. The region also includes Linnorm, Norway's largest undeveloped gas field.

- The Barents Sea, located within the Arctic Circle, remains relatively underexplored. Johan Castberg's 2025 start-up added a third processing hub alongside Snøhvit, which supplies the LNG facility, and the Goliat oil field, onstream since 2016. Limited gas export capacity – restricted to the Snøhvit terminal – remains a key challenge for new developments. Even so, exploration has continued, with a growing focus on near-field prospects. The Wisting oil project is likely to be the next major development but was postponed in late 2022 due to rising costs and execution risks. A revised development concept is expected in 2026.

Out to 2050, this study includes around 5.4[8] billion boe of yet-to-find resources in Norway, distributed across three key basins:

[8] *This study excludes 500 mmboe of West Barents gas resources, which Wood Mackenzie considers non-viable under current commercial and development assumptions due to lack of infrastructure, market access, and cost challenges.*

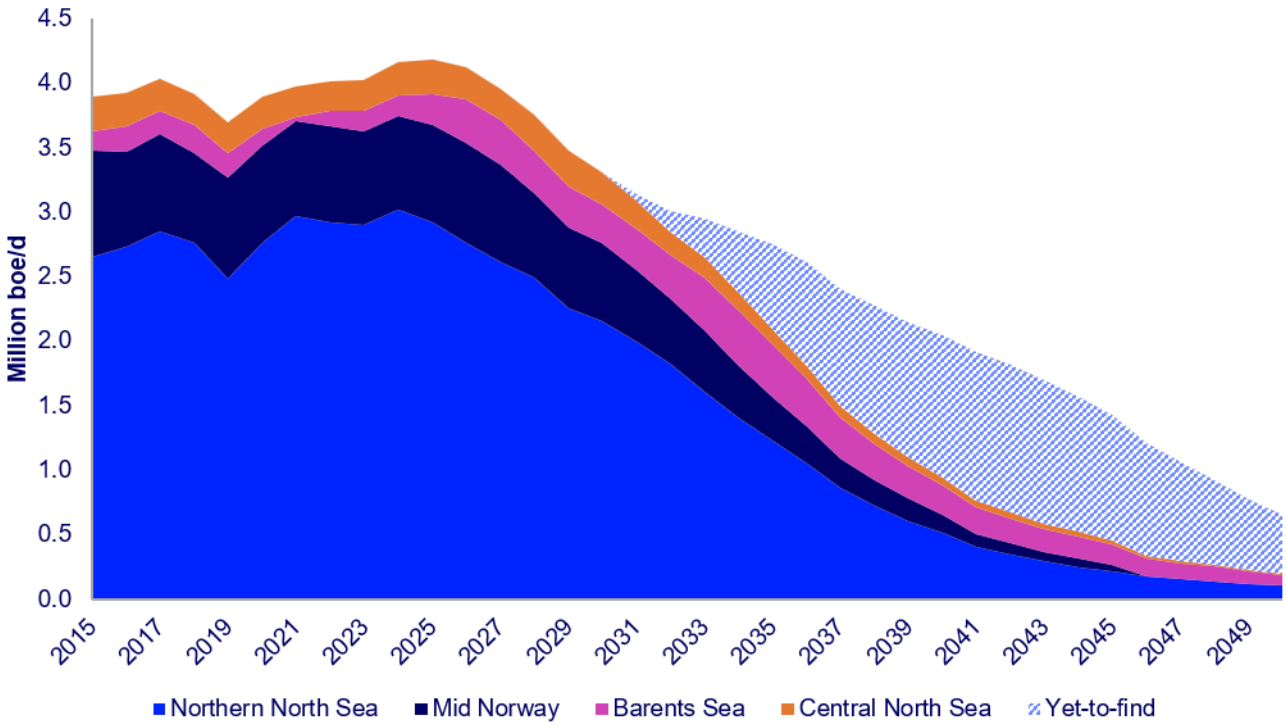
- The **Northern North Sea** basin contains approximately 2.9 billion boe of yet-to-find resources and is the most heavily explored basin in Norwegian waters, with over 600 exploration wells drilled to date. The basin architecture is dominated by the Viking Graben, with the Jurassic plays accounting for the majority of both well activity and volumes. These plays are expected to remain the primary focus of future exploration.

- The **Vøring** Basin holds an estimated 1.5 billion boe of yet-to-find resources. Located on the Mid Norwegian Shelf, this predominantly gas-prone province extends from shallow shelf areas into ultra deepwater exceeding 2,000 metres. Exploration has historically focused on Early to Middle Jurassic sandstones which were accessible along the Halten and Dønna Terraces in shelf environments. As the shelf plays are maturing, explorers are increasingly targeting near-field prospects within the thick Cretaceous and Paleogene stratigraphy in the deeper waters.

- The **West Barents Sea** basin contains approximately 0.8 billion boe of yet-to-find resources and represents one of Norway's most promising frontier areas. Following the Snøhvit discovery in 1984, the basin was long regarded as predominantly gas prone; however, discoveries over the past two decades have established clear liquids potential, significantly improving its exploration outlook.

- We also hold minor YTF volumes of around 150 mmboe in the **Central Graben** basin, which is a mature basin situated in the Central North Sea. Much of the exploration in the basin to date has focused on the Jurassic Sandstone and Upper Cretaceous Carbonate plays. However, the Julius (2015) and Othello (2024) discoveries renewed interest in the Jurassic and Paleocene Sandstone plays, where we forecast exploration drilling to continue with a focus on oil prospects.

Figure 2.2 Total production by basin, million boe/d



Source: Wood Mackenzie (April 2026). Includes Commercial (Onstream, Approved for Development and Justified for Development), Economically Viable, and YTF resources. Excludes Contingent and IOGR resources.

Figure 2.3 Remaining resources by product type, billion boe (2026)

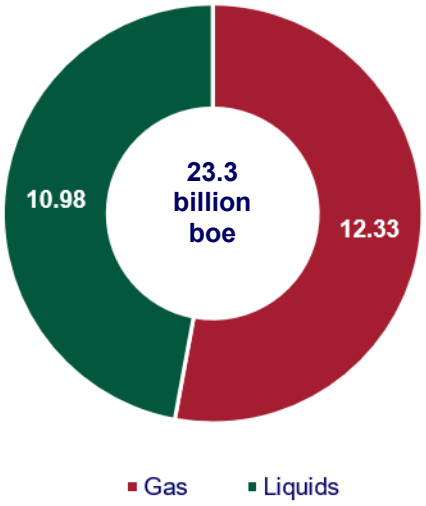
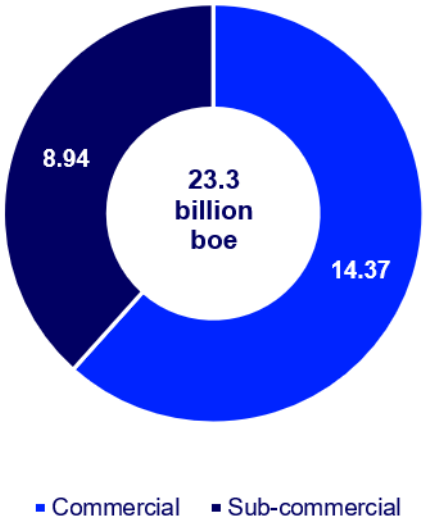


Figure 2.4 Remaining resources by commerciality, billion boe (2026)



Source: Wood Mackenzie. Includes Commercial (Onstream, Approved for Development and Justified for Development) and Sub-commercial (Contingent and Economically Viable) resources. Excludes IOGR and YTF resources. Contingent resources are considered economically unviable and are not included in the scenario analysis in Section 3.

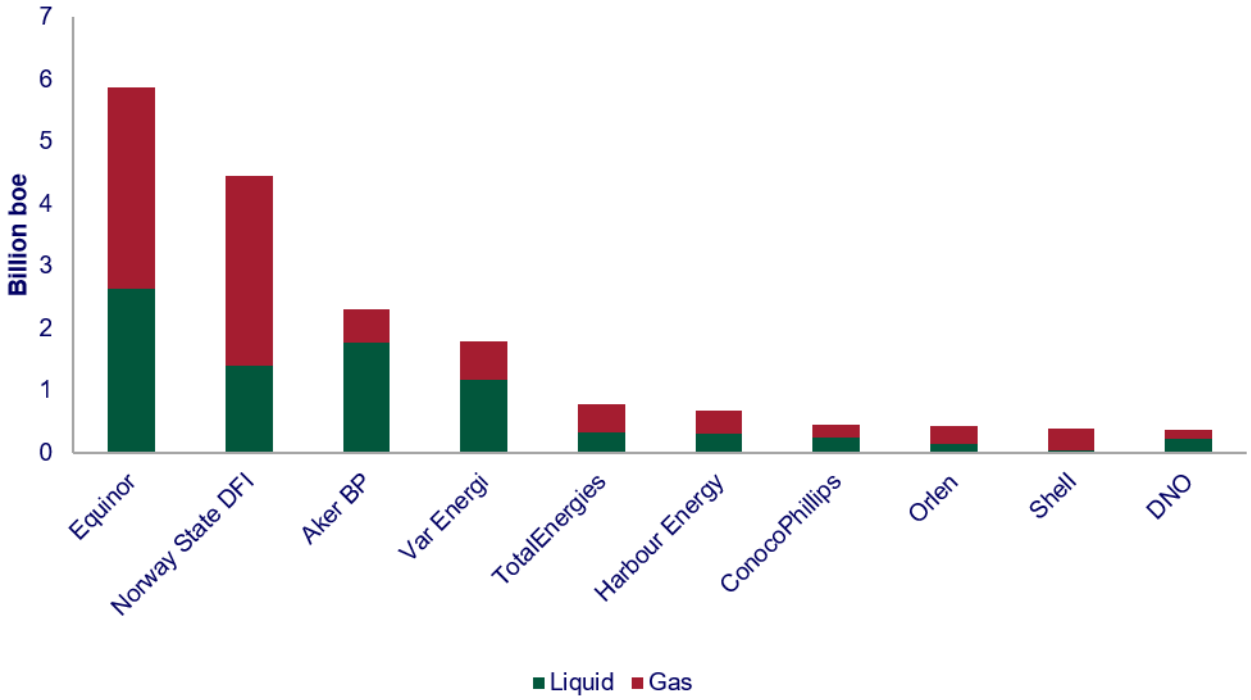
Norway's upstream sector is dominated by Equinor and the State Direct Financial Interest (State DFI[9]), which together account for around 60% of the country's remaining commercial reserves and value. Equinor has set ambitious goals to sustain production and investment, targeting 1.3 mmboe/d through 2035.

The corporate landscape has evolved over the past decade, becoming more consolidated. This shift was driven by the rise of private-equity-backed players in the 2010s, evolving strategic priorities among the Majors and IOCs, and the emergence of Norway-focused independents such as Aker BP[10] and Vår Energi[11], which act as dedicated operating vehicles for BP and Eni on the NCS, respectively. More recently, Harbour Energy has strengthened its Norwegian position through the acquisition of Wintershall Dea, while Orlen and DNO have also increased activity. DNO is pursuing rapid production growth through acquisitions and active exploration, while Orlen has been one of the most active buyers in recent years, focusing on pre-FID and producing gas assets alongside a portfolio of development projects largely operated by Aker BP. These players have grown rapidly and now rank among the largest independent oil and gas companies globally.

Norway's upstream sector has shifted from a fragmented mix of majors and smaller players to a concentrated group of scaled, well-capitalised independents, which now have the size and operational depth to drive investment, consolidation and production outcomes on the NCS – making capital allocation decisions by a small number of players increasingly more important for the basin. However, the basin is now exposed to the investment priorities of a handful of dominant operators, meaning any shift in their investment focus could disproportionately reduce exploration, development and long-term production across the basin.

[9] *State DFI's portfolio of oil and gas assets is managed by Petoro AS, which is a wholly state-owned company.*
[10] *Aker BP ownership – Private Investors (62.97%), AKER (21.16%), BP (15.87%)*
[11] *Vår Energi ownership – Eni (63.04%), Private Investors (36.96%)*

Figure 2.5 Net remaining resources by company (top 10), billion boe



Source: Wood Mackenzie (April 2026). Figure 2.5 includes 2P + 2C volumes.

2.3 Investment outlook

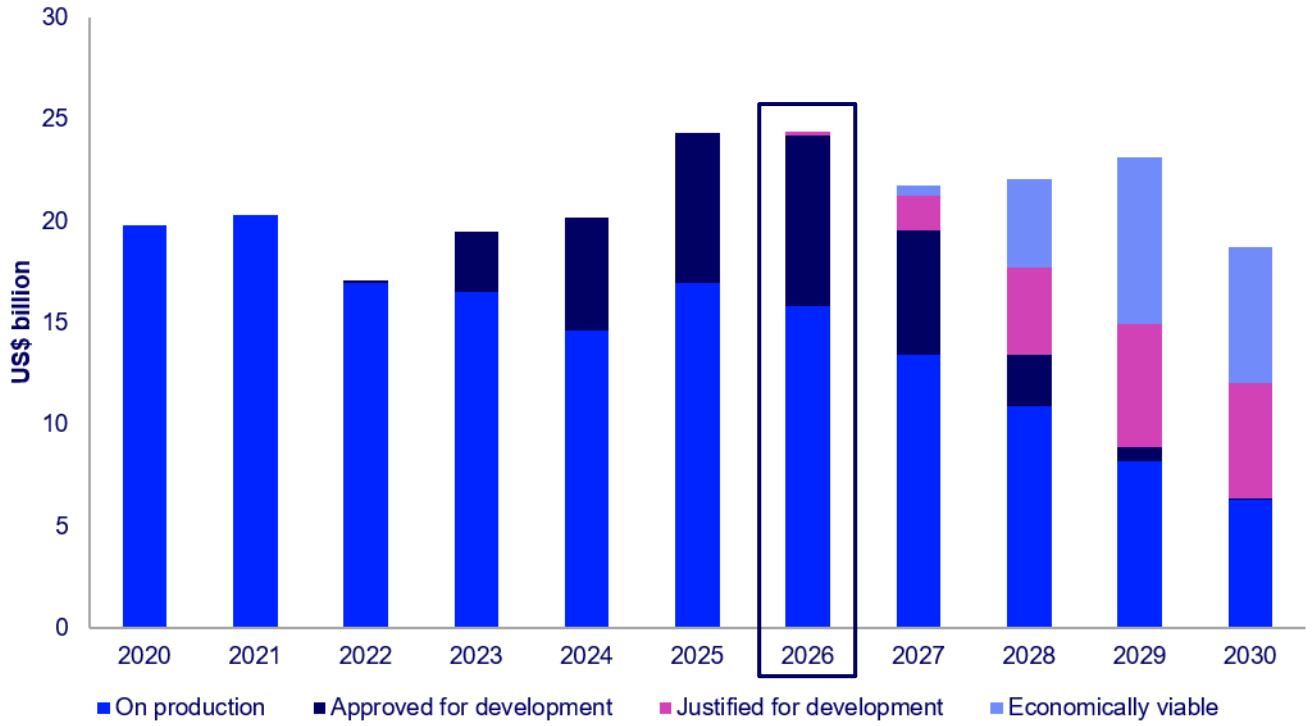
The temporary tax terms have underpinned the current cycle of development and investment. In June 2020, the Norwegian Government introduced a fiscal package to support and maintain investment levels as oil prices fell due to the Covid pandemic. The fiscal changes included immediate capital allowance against special tax for all investment in 2020 and 2021 and for any project sanctioned before end-2022. Thirty-five projects with a combined total investment of US$40 billion (NOK 386.8 billion) (2022 terms) were sanctioned in the window. The total reserves estimate for the 35 projects at the time of PDO submissions was around 2.5 billion boe.

Despite recent volatility and cost inflation, investment in Norway's oil and gas sector remains robust. We expect total capital development to decrease slightly from a 10-year high in 2025 as several projects move to the end of heavy investment phases. Pre-FID projects will become increasingly important toward the 2030s as operators look to restock project pipelines and start the next investment cycle. A substantial share of future projects will be subsea tiebacks to existing hubs.

Current projects will keep capex over US$20 billion (NOK 193.4 billion) in 2026. After that, the investment cycle begins to taper, and attention shifts to IOGR and a new wave of pre-FID projects to fill the emerging gap. There are already up to 60 projects currently near FID or in early phase evaluation. However, there is uncertainty, both in terms of scale and timing of these investments.

Overall, Wood Mackenzie estimates US$40 billion (NOK 386.8 billion) in justified and economically viable investment through 2030 – around 35% of total expected spend. Equinor, Aker BP and Vår Energi account for more than 70% of expected spending, underscoring their dominance in the sector. This also highlights potential concentration risk in Norway. The dominance of Equinor, Aker BP and Vår Energi brings clear advantages such as greater stability, capital discipline and infrastructure-led efficiency, enabling higher resource recovery and more reliable long-term gas and oil supply.

Figure 2.6 10-year investment horizon 2020-2030, US$ billion



Source: Wood Mackenzie (April 2026)

2.4 Scope 1 & 2 emissions analysis

Norway is a global leader in upstream decarbonisation. The Norwegian government aims to reduce its emissions by 70-75% by 2035 in comparison to 1990 levels[12]. Additionally, the country targets to become a low-emission society by 2050 and to reduce greenhouse gas emissions by 90-95% (as compared to the reference year 1990).

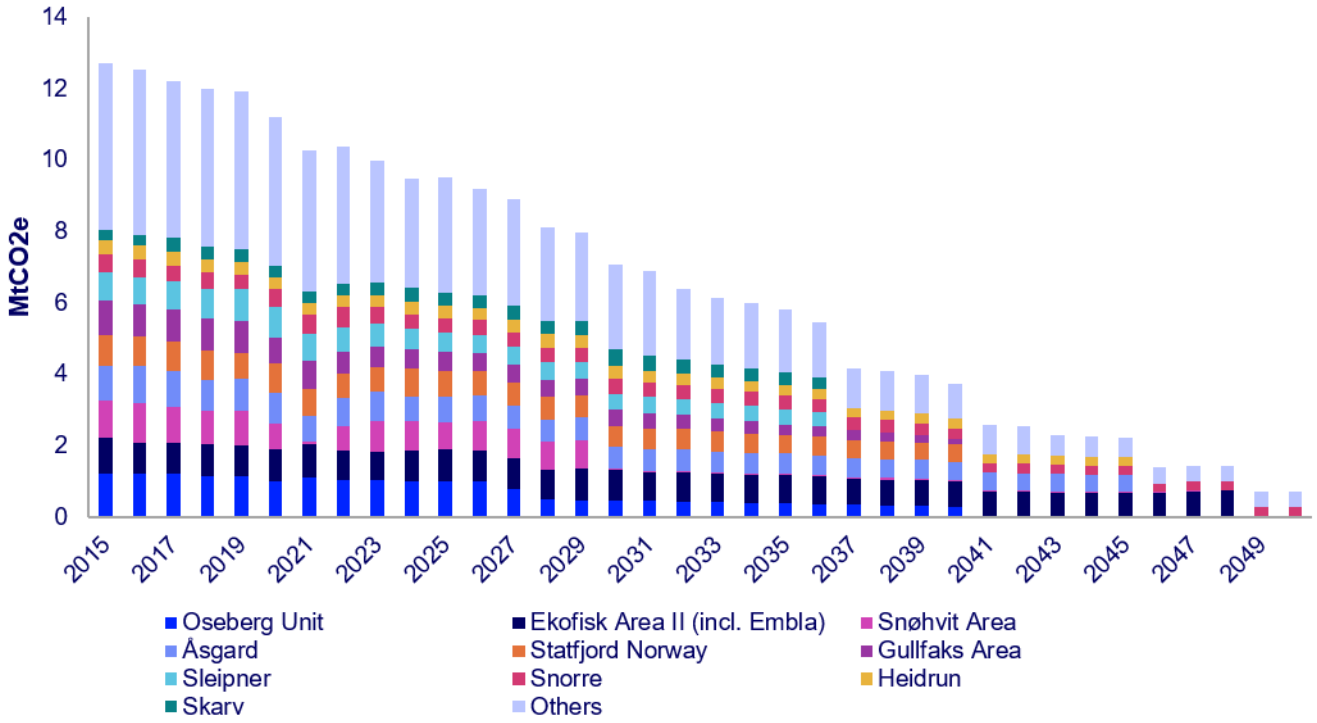
Norway has one of the lowest upstream carbon intensities in the world, driven largely by the progressive electrification of offshore facilities with power from shore. This shift has been driven by the combined cost of Norway's domestic CO2 tax and the EU ETS, which impose additional costs on emissions. Several of Norway's largest processing hubs – including Troll, Johan Sverdrup, and Ormen Lange – draw power from shore. As of 2026, over 50% of production is produced from either partially or fully electrified hubs (Figure 2.9).

Power from shore has supported Norway's drive to decarbonise and contributed to ambitious operator emissions reduction targets. Equinor is targeting a 50% absolute emissions reduction by 2030, compared to 2005 levels[13]. Project delays and cancellations pose downside risk to these targets. Since late 2025, three projects with power from shore to existing installations – Halten, Tampen and Balder/Grane – have been cancelled, as rising costs pushed electrification projects beyond their carbon value. Additionally, two offshore wind projects connected to oil and gas installations – Ekofisk and Brage – were also cancelled.

Emission taxes for the oil and gas sector are already the highest in the world, and authorities have set a goal to increase it to over US$260 per tonne (NOK 2,514 per tonne) by 2030. However, Norway's high carbon costs are tax-deductible against a high corporate tax rate (~78%) so the effective cost to operators is much lower.

[12] *Source: Norway's nationally determined contribution for 2035*
[13] *Source: Equinor Energy transition plan 2025*

Figure 2.7 Total annual emissions by hub, $MtCO_2e$ (Top 10 by emissions, 2026)



Source: Wood Mackenzie (April 2026). Figure does not include emissions from terminals or plants.

2.5 Status of electrification in Norway

Norway remains the global leader in offshore electrification. Today, over half of Norwegian oil and gas production is either partly or fully electrified resulting in an average emission intensity of around 7 tCO_2e/kboe compared to the global average of 22 tCO_2e/kboe, as per Wood Mackenzie's data.

Offshore power demand is also expected to rise from 11 TWh in 2023 to 16 TWh by 2030 from projects such as Troll B & C, Oseberg, Snøhvit LNG, Draugen/Njord and Yggdrasil. Several projects such as Snøhvit and Njord/Draugen are investing in grid upgrades to connect to power from shore. However, supply-chain pressures and permitting challenges are also driving up costs and extending timelines.

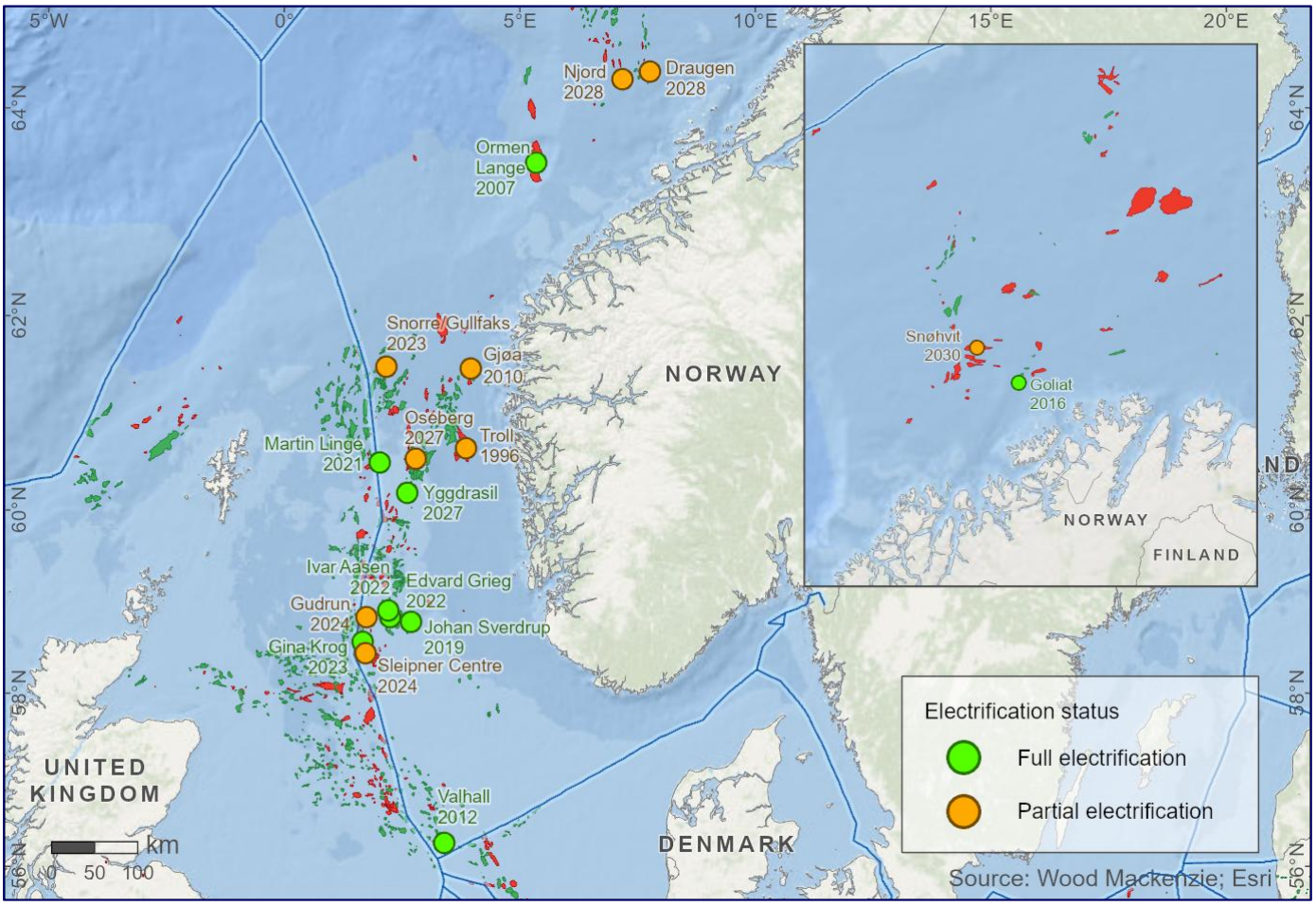
Figure 2.7 shows that Norway has already avoided over 3.5 million tCO2e per year since 2015, primarily driven by power from shore electrification – with more than 2 million tCO2e of additional annual reductions forecast by 2030.

Yet future progress is becoming harder. After significant investment decisions in 2022, several planned projects have been cancelled due to high project and abatement costs. Cost estimates have been reported between NOK 5,000 and 7,000 per tCO_2e. Projects discontinued in 2025 and 2026 included Halten (Åsgard B, Heidrun, Kristin and Skarv[14]), Snorre (Snorre A and B, Gullfaks) and the Grane Balder Energy Project. The three projects had combined capacity requirements of 435 MW and estimated annual emissions savings of over 1 million tCO_2e, equivalent to approximately 10% of total reported emissions in 2025.

Further, political uncertainty regarding the prioritisation of power grid access for the oil and gas sector – rather than a strict lack of physical power generation – has also emerged as a key risk going forward.

[14] *Skarv was included in the initial phase before being removed from the Halten development concept and assigned its own power-from-shore solution.*

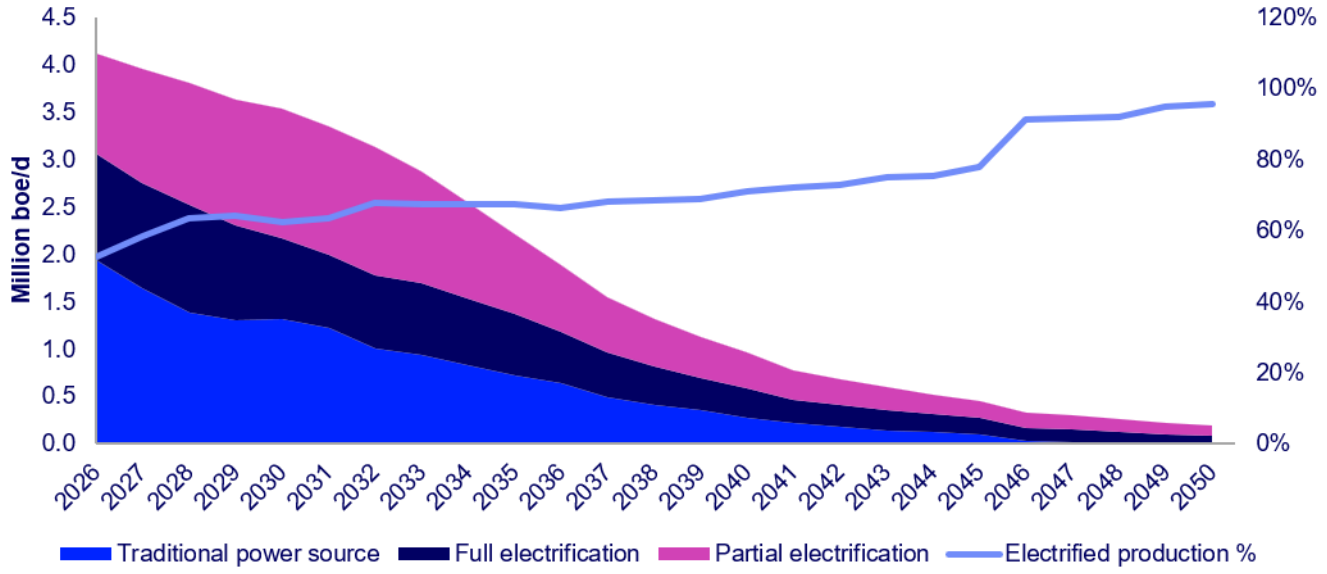
Figure 2.8 Norway oil and gas electrification field hub by status



Source: Wood Mackenzie

Electrification and carbon reduction have allowed Norway to position itself as a low-emission, reliable energy supplier. And replacing offshore gas turbines with grid power remains the most effective way to cut emissions. However, the recent cancellation of several large-scale power-from-shore projects calls into question the long-term viability of offshore electrification as a cornerstone of Norway's decarbonisation strategy. These were among the most feasible unsanctioned opportunities left on the shelf. Alternative abatement routes offer little relief: carbon capture and storage and offshore wind have both been assessed as even less feasible than power from shore, facing higher costs and weaker project economics. Their removal suggests that the era of relatively cost-effective, high-impact electrification is largely over. Future projects will face even tougher economics, implying a slower pace of deployment and greater reliance on production cutbacks rather than abatement investments to meet emissions targets. This also increases operators' exposure to rising carbon prices in future.

Figure 2.9 Total production by power source, million boe/d



Source: Wood Mackenzie (April 2026)

3 Scenario analysis on commercial and economically viable resources

The study assessed the impact of carbon taxes on oil and gas fields on the NCS for low- and high-case carbon tax scenarios. The model included a total of 164 fields across the entire NCS, with both commercial (onstream, approved for development and justified for development discoveries) reserves and economically viable discoveries, included in the analysis[15].

The 'static effects' analysis examined the impact of the low- and high-carbon tax scenarios on the following metrics:

1. NPV10[16] valuation of the NCS (sum-of-the-parts), pre- and post-tax
2. Government share (NPV10)
3. Remaining reserves (commercial plus economically viable) and field life
4. Decarbonisation initiatives
5. Emissions from the NCS

To examine the impact of the high carbon tax scenario on pre-FID developments, we apply a 15% IRR hurdle rate (the minimum threshold assumed to be used by oil and gas companies operating on the NCS) that fields must make to be considered for sanction. The key results from this section are summarised in Table 3.1 and discussed in detail in later sections.

Table 3.1 Summary results of the impact of low- and high-case CO2 taxes on commercial and economically viable fields

Metric Name	Low-case value	High-case value	Change (Abs/%)
Reserves (billion boe)	17.1	16.6	-0.5 (-2.8%)
Field life (Average year of field cessation)	2040.6	2038.6	-2 years
Pre-tax NPV10 (US$ billion)	434.5	431.6	-2.9 (-0.7%)
Investor Post-tax NPV10 (US$ billion)	63.5	59.8	-3.7 (-5.8%)
Government take (from profit-based taxes, CO2 tax and SDFI stake) (US$ billion)	371.5	371.8	0.3 (0.1%)

Source: Wood Mackenzie. Note: Investor Post-tax NPV10 excludes State DFI stake

The analysis in this section excludes 4.8 billion boe of contingent oil and gas resources in Norway which are considered 'Not Viable' under PRMS at the time of the study. These fields are not expected to be developed under our current costs and price projections due to reasons such as poor reservoir conditions, technological constraints, lack of infrastructure, contractual issues, etc. Several such fields are being evaluated on the NCS. Should they be considered for development in the future, then the impact of high CO_2 taxes could be similar to the analysis done in Section 4.

3.1 Impact on field life and reserves

The results of the scenario modelling presented in Figure 3.1 show that higher carbon taxes also have a measurable negative effect on both total recoverable reserves and field lifetimes on the NCS.

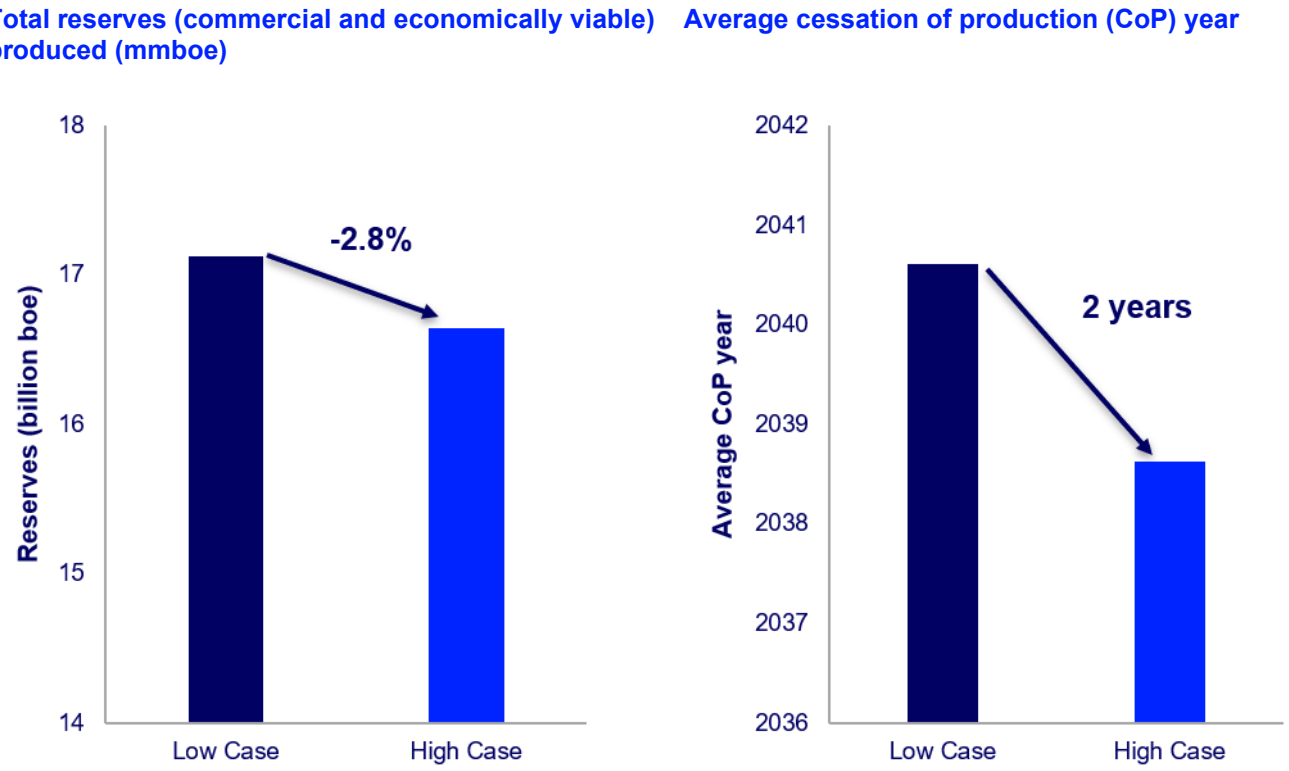
Higher carbon taxes reduce the economic viability of marginal production towards the end of a field's life. As a result, some production that would be profitable under a low carbon tax case becomes uneconomic under the high-case scenario.

[15] *This analysis excludes any contingent fields, which we do not expect to be developed under current costs and price projections*
[16] *Throughout this document, NPV10 refers to the net present value at our default central discount rate of 10% nominal. Discount date is 1 January 2026*

This leads to:

- **Remaining reserves declining** from around 17.1 billion boe in the low-case to 16.6 billion boe in the high-case – a reduction of 2.8% or approximately 490 million boe.
- **Average cessation of production (CoP)** occurring approximately two years earlier for most of the fields (2040–2041 in the low case versus 2038–2039 in the high case).

Figure 3.1 Impact of low- and high-case carbon tax scenarios on resources and field life



Source: Wood Mackenzie. This analysis excludes any contingent fields, which we do not expect to be developed under current costs and price projections. It also excludes IOGR and YTF resources.

The relatively modest 2.8% reduction in total reserves reflects the maturity of the NCS, where a large proportion of reserves are in large, long-life fields that remain robust even under higher carbon taxes. However, the impact is concentrated on smaller or higher-cost fields, where late-life production is particularly sensitive to increased opex.

The two-year earlier cessation of average field life is a direct consequence of the carbon tax which increases operating costs. Operators accelerate the point at which fields are shut in once marginal operating costs (including carbon tax) exceed marginal revenue. This effect is more pronounced on non-electrified fields, which face significantly higher CO2 costs per barrel. Our detailed methodology and approach to CoP modelling are described in Appendix A.

While the average advancement in cessation of production (CoP) is only two years in the high carbon tax scenario, the range varies widely, with 15 fields ceasing production between 5 and 16 years earlier. For example, Snorre and Ekofisk Area will reach their economic end of life 7-8 years earlier with a 7-8% reduction in reserves, as compared to the low case. Given that these fields act as hubs for the development of additional discoveries in the area, an earlier decommissioning of the fields could have a further impact on the economic viability of nearby discoveries, which could have been developed via the field's infrastructure.

The table below (Table 3.2) sets out the fields most affected under the high-case carbon tax scenario, detailing the reduction in reserves and the number of years by which CoP is brought forward relative to the low case, together with each field's electrification status, reflecting that the largest impacts fall on non-electrified fields.

Table 3.2 Fields with the largest changes in reserves and cessation of production between the low- and high-case carbon tax scenarios

Field	Low to High Reserves change (mmboe)	Low to High CoP year change (years)	Electrification Status
Yme Phase III	-6.7 (-46%)	-5	Non-electrified
Statfjord Nord	-7.8 (-43%)	-14	Non-electrified
Statfjord	-15.8 (-21%)	-11	Non-electrified
Tommeliten Alpha	-16.2 (-15%)	-16	Non-electrified
Tommeliten Gamma Ph. 2	-2.7 (-12%)	-7	Non-electrified
Tor II	-1.3 (-9%)	-7	Non-electrified
Ekofisk PPF	-6.1 (-8%)	-7	Non-electrified
Vigdis	-2.8 (-7%)	-8	Partial electrification
Snorre	-27.3 (-7%)	-8	Partial electrification
Visund Area	-7.3 (-5%)	-5	Non-electrified
Ekofisk Area	-13.7 (-4%)	-7	Non-electrified
Johan Castberg	-9.8 (-2%)	-5	Non-electrified
Åsgard	-2.4 (-1%)	-6	Non-electrified

Source: Wood Mackenzie. Ekofisk PPF comprises the joint re-development of the previously producing Vest Ekofisk, Albuskjell and Tommeliten Gamma fields. Tommeliten Gamma and Ekofisk PPF are modelled separately due to different participating interests in the assets.

Although higher carbon taxes have a limited aggregate impact on total reserves produced in absolute terms (~490 mmboe), they meaningfully accelerate the decline phase of the NCS, with material implications for long-term Norwegian petroleum revenue and government tax take, excluding the additional impact on employment and the oil and gas supply chain during the 2030s.

3.2 Impact on NPV10 of Norwegian oil and gas production

The results of the scenario modelling presented in Figure 3.2 show that a higher carbon tax reduces NPV10 in both pre- and post-tax cases. This is expected on a post-tax basis, since a higher CO_2 tax increases opex, lowering net cash flows. Since the CO_2 tax is tax-deductible, its net impact is partially offset by lower profit-based taxes. On a pre-tax basis the reduction in value is primarily due to the reduction in field life and reserves caused due to the early cessation of the fields.

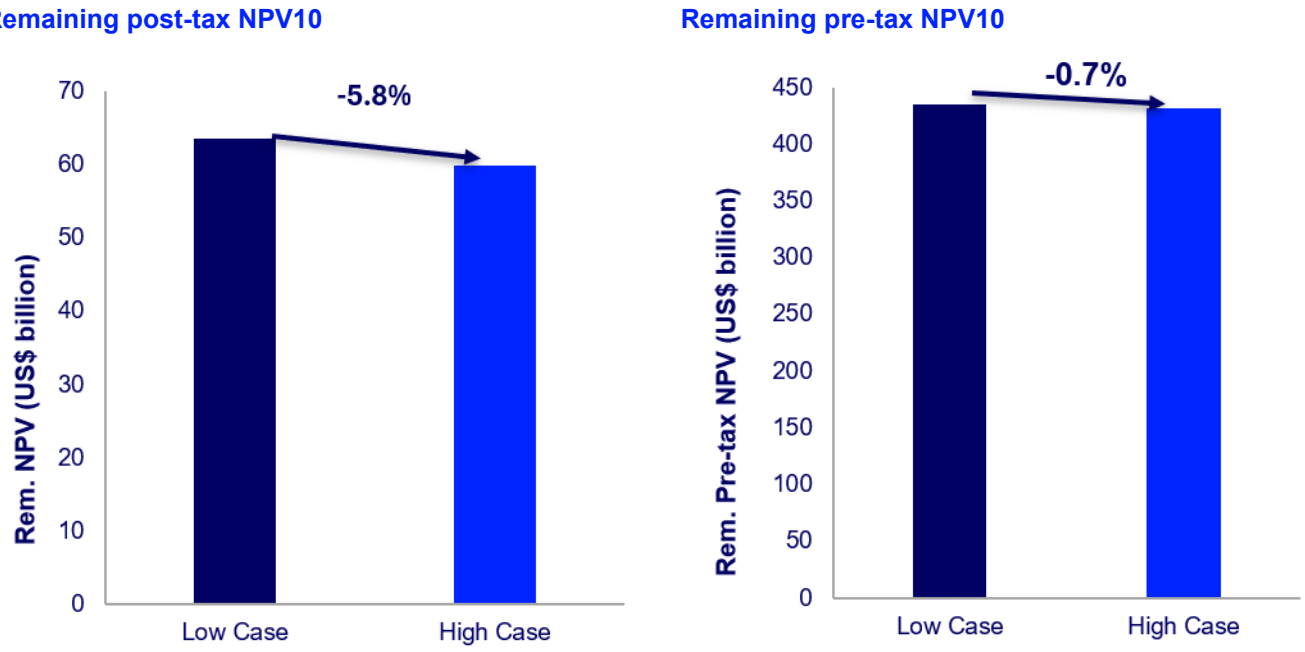
The impact on post-tax NPV10 is higher compared with the pre-tax impact. Value erosion rises from 0.7% (pre-tax) to 5.8% (post-tax). Overall, CO2 tax increases affect upstream economics, but the effect is significantly buffered by the tax deductibility and Norway's high baseline taxation rate.

The impact is greater on non-electrified, high-emission fields than on electrified, low-emission ones (Figure 3.2). For example, from an investor's point of view, Aasta Hansteen – a non-electrified field – loses around 17% of its post-tax value under the high carbon tax scenario. In contrast, a fully electrified field of similar size, such as Martin Linge, experiences a 3.4% loss in post-tax NPV10 valuation because of higher carbon taxes.

Comparing large non-electrified, partially electrified, and fully electrified fields – such as Johan Castberg, Troll, and Johan Sverdrup, respectively – reveals a more significant impact on the non-electrified Johan Castberg field, which loses around 2.9% of its value due to higher carbon taxes. In contrast, the values of Johan Sverdrup and Troll are hardly affected, with both losing only around 0.4–0.6% of their post-tax NPV10 in the high carbon tax case.

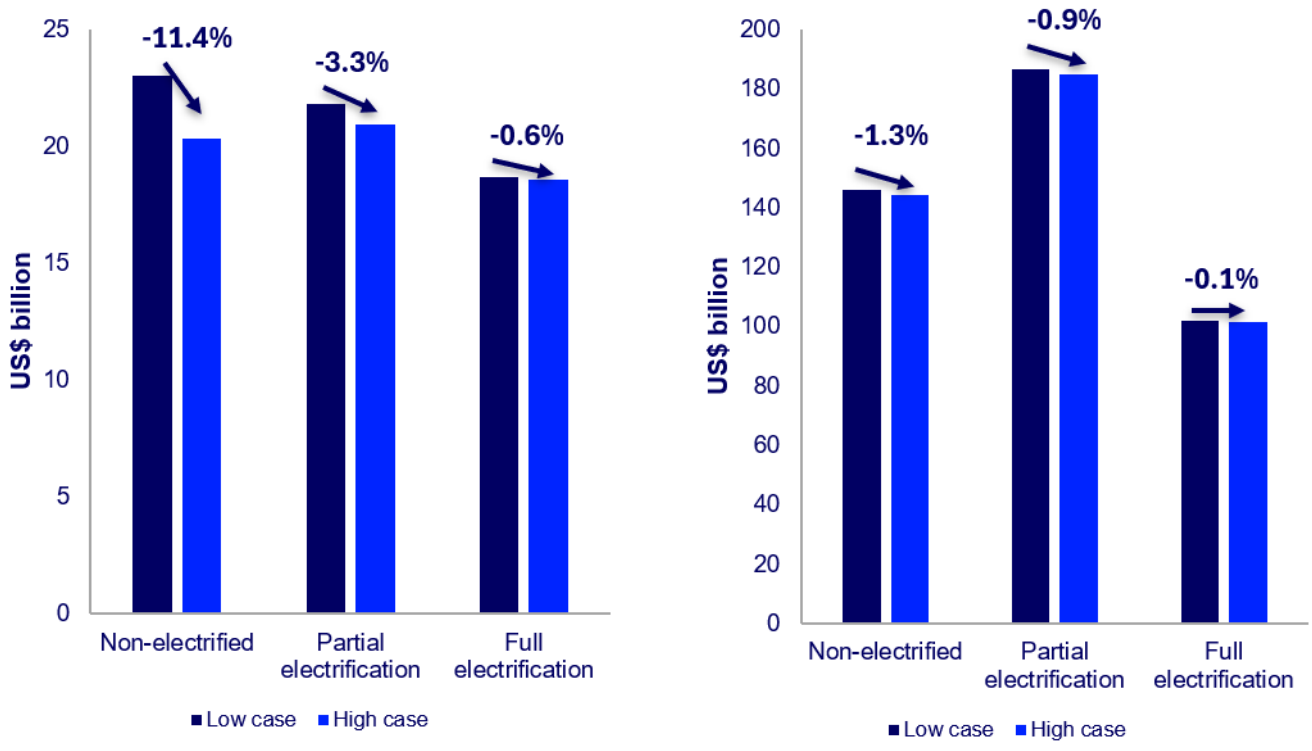
The analysis shows that while field size provides some protection through economies of scale, electrification status is the decisive factor for carbon tax sensitivity. A fully electrified giant such as Johan Sverdrup, or a partially electrified super-giant such as Troll, is almost immune to higher carbon taxes. In contrast, a non-electrified field like Johan Castberg is meaningfully affected by the increased CO2 tax burden.

Figure 3.2 Impact of low- and high-case carbon tax scenarios on NPV10 value of commercial and economically viable fields



Source: Wood Mackenzie. This analysis excludes any contingent fields, which we do not expect to be developed under current costs and price projections. It also excludes any IOGR and YTF resources.

Figure 3.3 Impact of electrification status on low- and high-case carbon tax scenarios on NPV10 value of commercial and economically viable fields



Source: Wood Mackenzie. This analysis excludes any contingent fields, which we do not expect to be developed under current costs and price projections. It also excludes IOGR and YTF resources.

3.3 Impact on government take from the commercial and economically viable fields

The higher CO_2 tax increases the total government share, as the rise in CO_2 tax receipts more than offsets the reduction in profit-based tax revenue (Table 3.3). This increase in the government share comes at the expense of a loss in NCS value and reserves.

Table 3.3 Impact of low- and high-case carbon tax scenarios on pre-, post-tax and government share NPV10

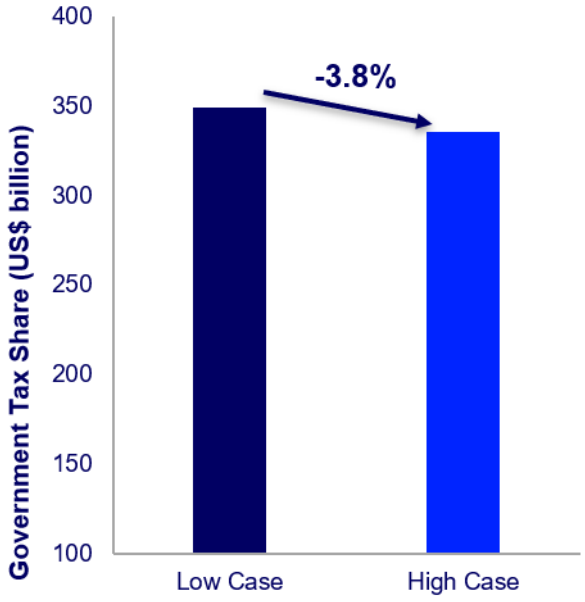
Metric (US$ billion, PV10)	Low Case	High Case	Change	% Change
Pre-tax NPV (excluding profit-based taxes and CO_2 tax)	434.5	431.6	-2.9	-0.7%
Investor Post-tax NPV	63.5	59.8	-3.7	-5.8%
Government Share, from profit-based taxes, CO_2 tax, and SDFI share	371.5	371.8	0.3	0.1%

Source: Wood Mackenzie. Profit-based taxes refer to corporate income tax and special tax

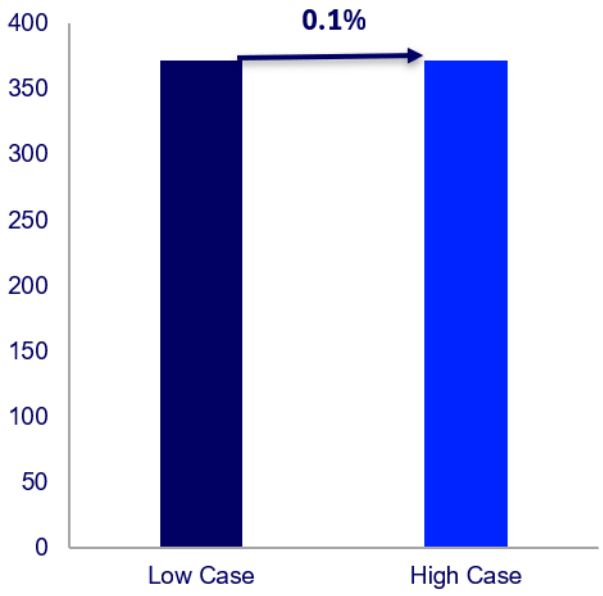
The Government's share from profit-based taxes, CO_2 tax and SDFI share equates to approximately 86% of pre-tax revenue in both low and high CO_2 scenarios, on a discounted basis.

Figure 3.4 Impact of low- and high-case carbon tax scenarios on Government share

Remaining NPV10 of the Government Share from profit-based taxes



Remaining NPV10 of the total Government share from profit-based taxes, SDFI share and CO_2 tax



Source: Wood Mackenzie. This analysis excludes any contingent fields, which we do not expect to be developed under current costs and price projections. It also excludes IOGR and YTF resources.

3.4 Impact on decarbonisation initiatives

The scenario analysis presented in the sections above demonstrates that carbon tax levels have a material influence on the economic incentives for offshore electrification.

A low carbon tax scenario would significantly weaken the business case for future electrification projects. Because non-electrified and partially electrified fields suffer substantially greater value erosion under higher CO_2 taxes (e.g., 17% for Aasta Hansteen and 2.9% for Johan Castberg), a low-tax environment reduces incentives to evaluate the economic viability of the capital expenditure required for grid connection, offshore wind integration or even carbon capture. With reduced exposure to CO2 costs, there would be no further electrification projects even under a more attractive cost and capacity environment. Smaller energy efficiency initiatives may also become less attractive beyond operator emissions reduction targets.

On the other hand, a high carbon tax scenario does not automatically accelerate electrification as one might expect. While it increases the cost penalty on non-electrified production and makes projects like Troll B & C, Oseberg, and Yggdrasil more attractive on paper, the high capital costs and long payback periods of many remaining electrification opportunities mean that even a steep rise in CO2 tax may be insufficient to overcome investment hurdles at this time. This is illustrated by the recent cancellation of several major power-from-shore projects – including Halten, Tampen, and Balder/Grane – due to very high project costs and abatement costs.

Operators may instead choose to absorb the cost of carbon taxes and manage the cessation of production on marginal, high-emission fields (as shown by the two-year earlier average CoP and 490 mmboe left in the ground in the high-case scenario) rather than invest billions in electrification. This is particularly true for smaller or more remote fields where abatement costs per tonne of CO2 avoided remain prohibitive.

Therefore, while higher carbon taxes strengthen the theoretical incentive to electrify, they do not guarantee higher rates of decarbonisation of the NCS. Emission reduction initiatives are likely to be limited to operational and energy efficiency gains. Given current cost levels and project complexity, a high CO2 tax regime may simply result in earlier field shutdowns rather than widespread new electrification investments, or other large-scale emission reduction projects.

3.5 Impact on production, state cash flow and emissions in the short, medium and long term

We have analysed the scenario results to determine the impact of low and high CO_2 taxes on Norway's oil and gas production and state cash flow over distinct periods of time as detailed below:

Production

In the short term (2026–2030), production is effectively unchanged between the two scenarios, with the low- and high-case profiles diverging only from 2030 onwards and an average drop of around 0.1 kboe/d over the period. The impact remains modest in the medium term (2031–2035), with production under the high-case carbon tax averaging 6.5 kboe/d (0.2%) lower than under the low case. The divergence widens materially in the long term (2036–2045), where the higher carbon tax erodes the economics of later-life production and brings forward field cessation as production averages 61.9 kboe/d (6.3%) lower than under the low case, with the annual gap reaching roughly 81 kboe/d by 2045. This pattern reflects the cumulative effect of a sustained higher carbon price – rising to approximately NOK 6,100 per tonne by 2050 under the high case, compared with around NOK 1,200 per tonne under the low case – which progressively shortens economic field life rather than curtailing near-term output.

Table 3.4 Average drop in production between the low- and high-case scenario over time

	2026-2030	2031-2035	2036-2045
Average drop in production (kboe/d)	0.1	6.5	61.9
% drop in production	-	0.2%	6.3%

Source: Wood Mackenzie

State income

In the short and medium term, the high-case carbon tax increases the state's take, as the higher carbon price raises CO_2 tax receipts faster than it erodes production and profits: state income averages around US$328 million (NOK 3.1 billion) (0.6%) higher in 2026–2030 and US$423 million (NOK 4.1 billion) (1.1%) higher in 2031–2035 than under the low case. The position inverts from 2036 onwards. In the long term (2036–2045) the contraction in production and the associated decline in tax and SDFI cash flow outweigh the additional carbon tax revenue, leaving state income on average US$250 million (NOK 2.4 billion) (1.9%) lower than under the low case, with the annual shortfall widening to roughly US$511 million (NOK 5 billion) by 2050. The high-case carbon tax therefore brings forward state revenue at the expense of the long-term value of the resource base.

Table 3.5 Average increase in state income between low- and high-case scenarios over time

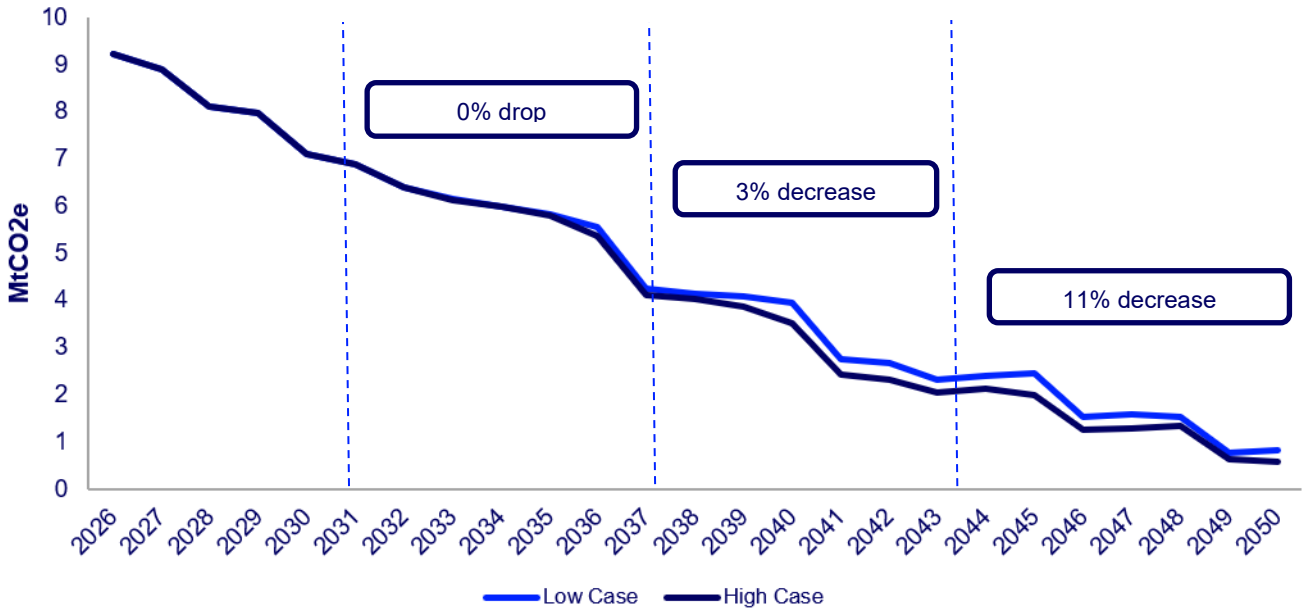
	2026-2030	2031-2035	2036-2045
Average increase in state income (US$ million, nominal)	328.4	423.3	-250.5
% increase in state income	0.6%	1.1%	-1.9%

Source: Wood Mackenzie. State income includes Corporation Tax, Special Tax, and CO_2 tax

Emissions

The impact of high CO_2 taxes on field and hub emissions is primarily driven by the early cessation of fields and hubs in the high-case scenario, resulting in a larger decrease in emissions only in the longer term compared to the low-case scenario.

Figure 3.5 Total emissions in low- and high-case scenarios



Source: Wood Mackenzie. The numbers in the callout boxes represent the average drop in emissions over the 5-year period shown. This analysis excludes any contingent fields, which we do not expect to be developed under current costs and price projections. It also excludes IOGR and YTF resources.

Emissions from the commercial fields are shown in Figure 3.5. Both the low and high scenarios follow the same emissions path from 2026 to 2029, with CO_2 tax having a limited impact on emissions. From 2030 onward, emissions begin to diverge as production profiles change. The difference is initially small – by 2035, emissions in the high case are only around 0.5% lower than in the low case, but it widens steadily through the 2040s. This is driven by higher carbon prices accelerating production cessations across the NCS.

By 2040, emissions in the high case are about 11% lower (3.5 vs 3.9 MtCO2e), increasing to roughly 19% by 2045. Over the full period from 2026 to 2050, cumulative emissions in the high-tax scenario are around 3.6 MtCO2e lower than in the low case (109.6 vs 113.3 MtCO2e), equivalent to a reduction of about 3.2%. Non-electrified fields such as Ekofisk, Tommeliten Alpha, Visund, Heidrun, and Dvalin show the most significant impacts, with production ceasing on average approximately five years earlier than in the low case. This results in a loss of over 150 mmboe in cumulative reserves and an estimated total NPV reduction of approximately US$1.9 billion (NOK 18.4 billion).

4 Scenario analysis on new resource development

Beyond the commercial and economically viable resource base examined in Section 3, the long-term value of the NCS is also dependent on the development of yet-to-find (YTF) prospective resources and IOGR volumes. In this section, we have extended the scenario modelling to assess the impact of low- and high-case CO2 tax scenarios on Norway's prospective resource potential. The analysis covers 179 modelled prospects across the NCS, expected to be developed via tie-backs to existing hubs, as the viable development solution for new discoveries[17]. This means that the emissions cost associated with a YTF development is impacted by the host facility into which it is tied.

The analysis in this section examines the impact of the low- and high-carbon tax scenarios on the following metrics:

1. Volume and value of Norway's YTF resources
2. Government share (NPV10) from YTF developments
3. Impact on Norway's long-term production profile and exploration outlook[18]
4. Indicative analysis on the impact on Improved Oil and Gas Recovery (IOGR) initiatives on existing fields

In the high-case scenario, higher CO2 costs set off a knock-on effect across YTF developments. As several marginal prospects drop out of the analysis (due to low IRR caused by high CO_2 costs), the remaining prospects must absorb a larger share of the emissions-cost burden carried by their host hub. This raises their CO2 cost exposure, tipping more fields below the investable threshold and reducing the volume of YTF resource ultimately developed. In the base modelling, each YTF prospect is assessed on the assumption that the other prospects around its host hub are also developed and able to share the hub's emissions and infrastructure costs. The knock-on effect described above, whereby the exit of non-investable prospects concentrates that cost burden on the remaining prospects, is not itself captured within this prospect-by-prospect modelling. To gauge its scale, the study took a pragmatic approach, quantifying the additional cost burden that falls on the surviving prospects once the non-investable ones drop out under a high CO2 tax (refer Appendix A).

To capture the knock-on impact of higher CO_2 taxes as prospects drop out in the high tax scenario, we modelled a scenario with a weighted average uplift of 50% to the CO_2 taxes. This illustrates the impact of fewer prospects being developed concurrently than the model assumes, causing the emissions-cost burden on each to be materially higher. The results in this section are therefore shown as a range to capture the potential for CO2 costs to become more concentrated, giving a more realistic spread of outcomes for some hubs and YTF developments during the development phase.

All modelled prospects are technically economic, with post-tax NPV10 above zero. However, consistent with the approach in Section 3, we apply a 15% IRR hurdle rate (the threshold assumed to be used by oil and gas companies), below which we assume a prospect will be unable to attract investment. Prospects clearing this threshold are referred to throughout this section as 'investable'. The key results of the analyses are summarised in Table 4.1 below and discussed in detail through the rest of the section.

Table 4.1 Summary results of the impact of low- and high-case CO_2 taxes on yet-to-find resources

Metric Name	Low-case value	High-case value	Change (Abs/%)
Pre-tax NPV10 (US$ billion)	27.8-28.7	23.8-26.1	-2.5 to -4.0 (-9% to -14%)
Investor Post-tax NPV10 (US$ billion)	4.7-4.8	3.5-4.0	-0.8 to -1.1 (-17% to -24%)
Government take (from profit-based taxes, CO2 tax and SDFI stake) (US$ billion)	23.3-24.0	20.3-22.1	-1.8 to -3.0 (-8% to -13%)
Reserves (billion boe)	4.6-4.7	3.7-4.2	-0.6 to -0.9 (-12% to -19%)

Source: Wood Mackenzie

[17] *Based on Wood Mackenzie's analysis over 90% of the YTF discoveries expected on the NCS will be smaller than 50 mmboe. As such, the resource size is too small to justify a standalone development.*

[18] *The analysis does not assume any extension of production from host or satellite fields within a hub because of YTF developments. Beyond field economics, this would depend on field-specific factors such as remaining reserves and reservoir dynamics that cannot be reliably quantified here. Note that the loss of reserves and value from non-development of YTF prospects under a high CO2 tax could be greater if such production extension were taken into account.*

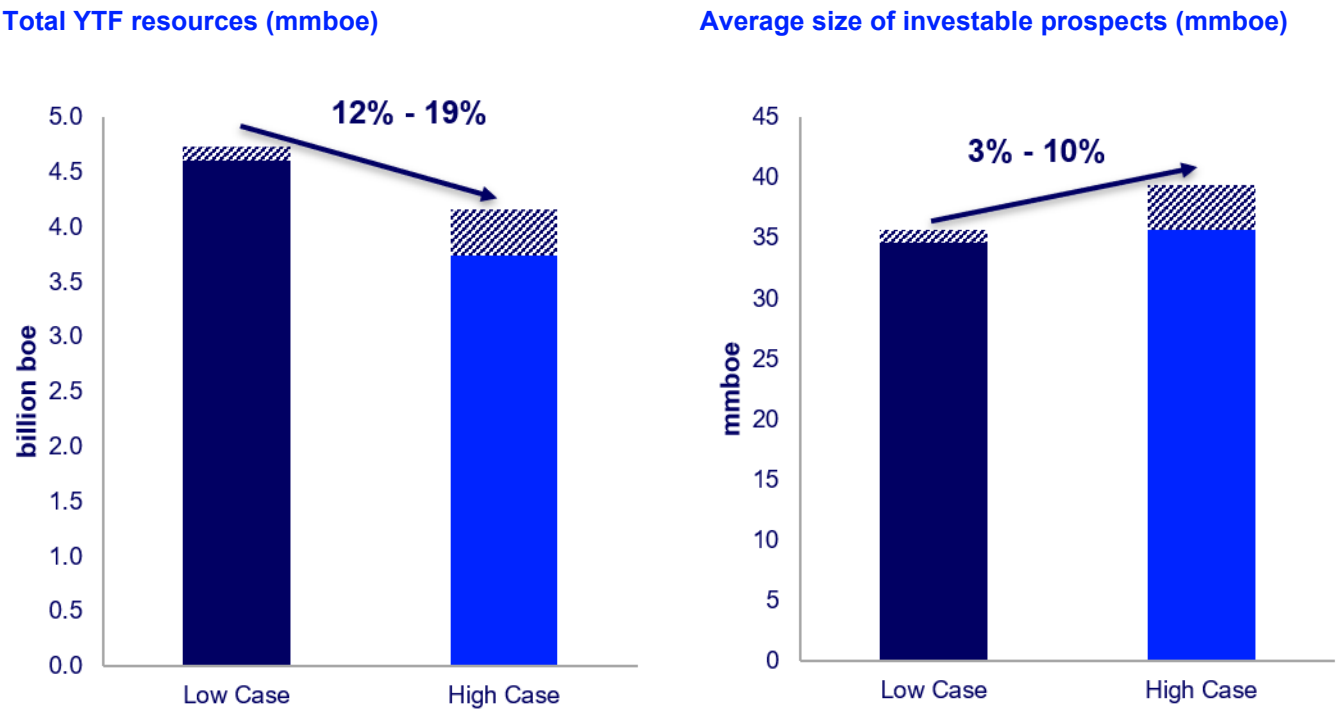
4.1 Impact on Norway's yet-to-find resources

The results of the scenario modelling presented in Figure 4.1 show that a higher carbon tax has a materially larger impact on Norway's yet-to-find resource base than on its commercial reserves. Under the low-case carbon tax, the 179 modelled prospects deliver between 4.6 and 4.7 billion boe[19] of investable YTF resources. Application of the high-case carbon tax reduces this to between 3.7 and 4.2 billion boe.

The drop reflects the combined effect of additional CO2 costs on smaller, marginal prospects and a corresponding tightening of the investable prospect set. The contraction is driven almost entirely by the smaller end of the prospect distribution, especially those which are discovered later and exposed to higher CO_2 taxes. Sub-20 mmboe prospects are particularly exposed: 30 of the 59 prospects in this band are investable under the low case, but only 14 remain investable under the high case, a fall of more than half. In the 20–40 mmboe band, 16 of 62 prospects drop out of the investable set, while prospects above 75 mmboe are essentially unaffected. As a result, the average size of an investable prospect rises from around 35 mmboe under the low case to between 38 and 39 mmboe under the high case, a 10% increase. This leaves between 600 and 850 mmboe of YTF resources remaining undeveloped.

The electrification status of the host hub is a decisive factor for sensitivity, as it is in commercial fields (Section 3.1). Of the 85 prospects tied into non-electrified hubs, 16 to 17 drop out of the investable set under the high case, with associated resources falling by 16-22% (~300-400 mmboe) under the high-case CO2 tax scenario. Prospects tied into partially electrified hubs see a similar erosion of 14% to 25% of reserves. In contrast, the 39 prospects tied into fully electrified hubs are largely insulated, losing only 4% to 6% of reserves and just three to four prospects from the investable set. Prospects tied into hubs such as Johan Sverdrup and Yggdrasil remain robust to higher carbon taxes, while those dependent on non-electrified hubs such as Skarv, Aasta Hansteen and Johan Castberg become unviable when developed later, due to higher CO_2 costs.

Figure 4.1 Impact of low- and high-case carbon tax scenarios on YTF resources and field life



Source: Wood Mackenzie. Hashed areas represent the range of uncertainty due to the emissions associated with the YTF volumes. This analysis includes only YTF resources.

4.2 Impact on the value of Norway's yet-to-find resources

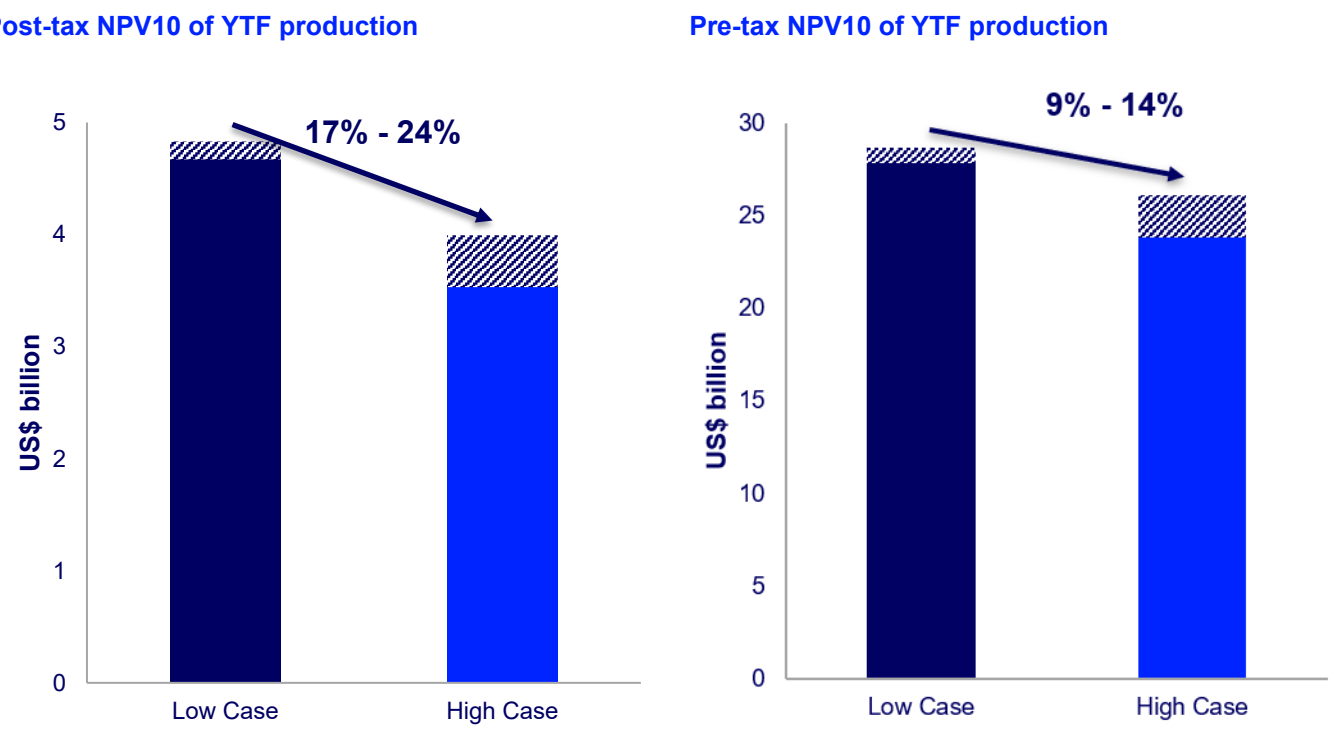
The results of the scenario modelling presented in Figure 4.2 show that the high-case CO2 tax scenario reduces the aggregate pre-tax NPV10 of Norway's investable YTF resources by 9-14% compared to the low-case CO2 tax scenario,

[19] *Wood Mackenzie's base case for YTF outlook (as described in Section 3) includes 5.4 bnboe of economically viable oil and gas resources. However, the application of a minimum IRR of 15% reduces this to 4.7 bnboe which is used throughout the rest of this study.*

from ~US$28-29 billion (NOK 270-280 billion) to US$24-26 billion (NOK 231-251 billion). The scale of the value destruction is larger than the equivalent reduction in the commercial resource base (Section 3.1). This reflects that YTF prospects can sit at the margin of investability and therefore are more exposed to emissions-related cost risk. The post-tax NPV10 of the portfolio falls by a much larger percentage under the high-case scenario, from US$4.7-4.8 billion (NOK 45.8-47.3 billion) to US$3.5-4.0 billion (NOK 34.6-39.1 billion).

The value impact is heavily differentiated by the electrification status of the host hub. Prospects tied into non-electrified hubs see post-tax NPV10 fall by 25% to 35% under the high-case CO2 tax with pre-tax NPV10 reducing 10% to 15% reflecting the YTF volumes which remain in the ground. Partially electrified hubs experience a similar erosion, ranging from 17% to 25% in post-tax value (12% to 21% in pre-tax). In contrast, the prospects behind fully electrified hubs lose only 5% to 6% of post-tax value (3-4% pre-tax) under the high-case scenario. As expected, the divergence underscores the value of electrification as a structural hedge against carbon tax escalation: prospects with fully electrified hosts not only retain a higher proportion of their NPV10 but also maintain a more stable investor proposition across the range of CO2 tax outcomes modelled. This may also shape exploration decisions by operators on the NCS, as discussed further in Section 4.5.

Figure 4.2 Impact of low- and high-case carbon tax scenarios on NPV10 value of Norway's YTF resources



Source: Wood Mackenzie. Hashed areas represent the range of uncertainty due to the emissions associated with the YTF volumes. This analysis includes only YTF resources.

4.3 Impact on the government take from yet-to-find resources

The results of the scenario modelling presented in Figure 4.3 show that, unlike the commercial resource base analysed in Section 3.3, the total government take from Norway's investable YTF resources falls materially between the low- and high-case carbon tax scenarios when taxes, the SDFI stake[20] and CO_2 taxes are included.

Total government take declines from US$23.3-24.0 billion (NOK 228.6-234.8 billion) under the low case to US$20.3-22.1 billion (NOK 199.2-216.9 billion) under the high case, a reduction of US$1.8-3.0 billion (NOK 17.8-29.3 billion), or 7.6-12.8%. The decline results from many YTF prospects remaining undeveloped under the high-case CO_2 tax scenario, forgoing value that the barrels could have generated.

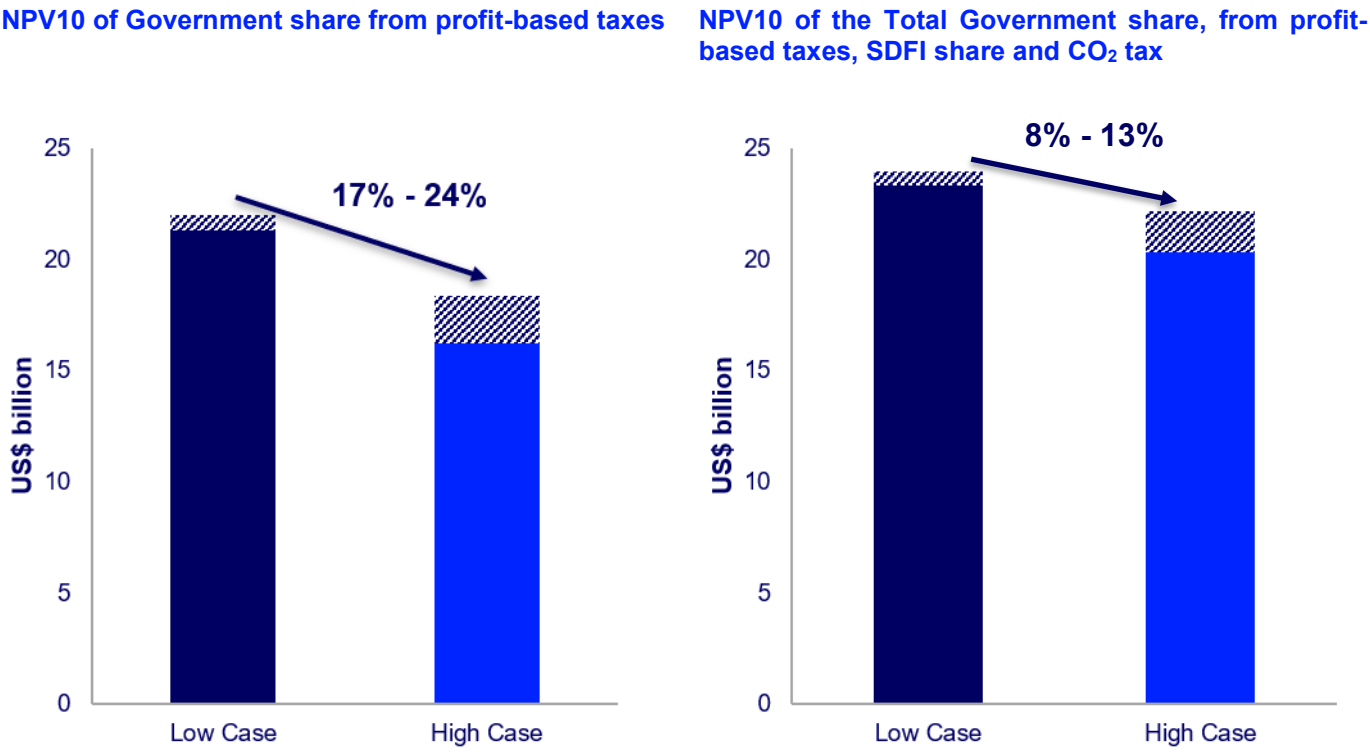
The result is also a material shift in the composition of government take: under the high-case scenario, the state recovers

[20] *The State DFI stake for the YTF fields is calculated assuming an average equity stake of 28%. This represents the proportion of State DFI's current pre-tax NPV to the pre-tax NPV of all Norwegian assets, based on Wood Mackenzie data. Calculated using a discount rate of 10% discounted to Jan 2026.*

through CO_2 taxes, which rise by US$2.1-2.6 billion (NOK 20.3-25.1 billion), only a part of what it forgoes in profit-based taxation, so the carbon receipts soften but do not offset the decline in total take. This is in contrast with the commercial resource (Section 3.3) base, where the higher CO_2 taxes are absorbed within producing fields and the carbon taxes that the state collects almost exactly offset the profit-based taxes it forgoes, leaving total government take broadly flat.

For yet-to-find resources, the development decision is not fixed: the high-case CO_2 tax pushes marginal prospects below the investment threshold, so they are never sanctioned and the resources, together with the tax they would have generated, never materialise. Where Section 3.3 showed the upstream investors paying the additional CO_2 tax and offsetting the loss in profit-based taxes, here the state loses the revenue outright on barrels that are no longer developed at all.

Figure 4.3 Impact of low- and high-case carbon tax scenarios on Government share from yet-to-find resources



Source: Wood Mackenzie. Hashed areas represent the range of uncertainty due to the emissions associated with the YTF volumes. This analysis includes only YTF resources.

4.4 Short, medium and long-term impact of low- and high-case carbon taxes on Norway's yet-to-find outlook and emissions

The volume and value impacts set out in Sections 4.1 and 4.2 summarise the total effect of the low and high carbon scenarios to 2050. However, these effects are not felt evenly over time. Because each prospect is modelled from the year it is expected to be drilled and discovered, the effect of a higher carbon tax on the yet-to-find portfolio can be phased across the short term (2026-2030), medium term (2031-2035) and long term (2036-2045), as summarised in Table 4.2.

In volume terms, the high-case CO_2 tax removes broadly similar quantities of investable resource in each period (around 230 to 300 mmboe in the short term, 179 to 316 mmboe in the medium term and 171 to 245 mmboe in the long term), but the proportionate impact deepens over time, from 12-17% of investable volumes in the short term to 15-23% in the long term. This reflects the progressive tightening of the investable set as a sustained higher carbon price pushes a growing share of smaller, later prospects below the 15% IRR threshold.

The value (pre-tax NPV10) of prospects falls by 10-14% in the short term, 7-14% in the medium term and 8-16% in the long term. This divergence between the value and volume effects reflects the disproportionate weight of emissions-related costs on marginal prospects. As the carbon price rises through the forecast, later prospects that remain viable

are still developed, but at materially lower value.

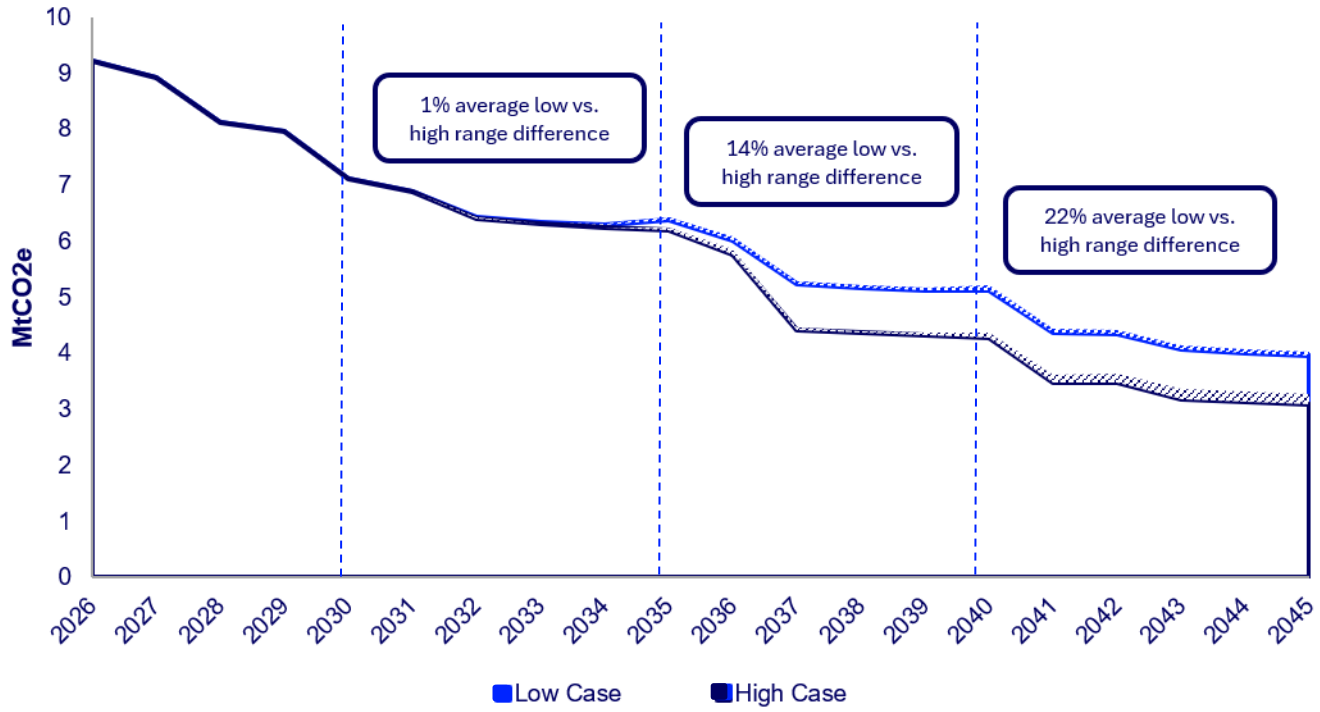
Table 4.2 Impact of CO_2 taxes on the value and volume of YTF resources over time using discovery year

	2026-2030	2031-2035	2036-2045
Decrease in YTF volumes (mmboe)	230-300	179-316	171-245
% decrease in YTF volumes	12-17%	10-19%	15-23%
Decrease in the value of YTF resources (pre-tax NPV10 (Jan 2026), US$ billion)	1.5-2.0	0.7-1.3	0.4-0.7
% decrease in the value of YTF resources	10-14%	7-14%	8-16%

Source: Wood Mackenzie. Note: The year ranges shown represent the year when the prospect is drilled and discovered.

Impact on emissions

Figure 4.4 Total (commercial + yet-to-find) emissions in low- and high-case scenarios



Source: Wood Mackenzie. Hashed areas represent the range of uncertainty due to the emissions associated with the YTF volumes.

Figure 4.4 highlights the emissions outcomes between the low- and high-carbon price cases. In the low case, extended production from additional developments leads to a more gradual decline in Norway's total emissions, whereas in the high case, earlier and more widespread hub closures drive sharper reductions. The difference becomes increasingly pronounced through the late 2030s and 2040s. By 2040, emissions in the high case fall to 4.3–4.4 MtCO2e, around 16% below the low case (5.1–5.2 MtCO2e), declining further to 3.1–3.3 MtCO2e by 2045, approximately 23% below the low case (3.9–4.0 MtCO2e). Looking further ahead to 2050, the divergence remains significant, with an average 31% spread between the low- and high-case outcomes, driven primarily by hub closures and progressively lower production volumes.

The emissions trajectories indicate a stronger response to carbon pricing than is observed for commercial fields alone, once the additional emissions associated with the development of yet-to-find resources are included.

Under higher carbon prices, a greater proportion of yet-to-find volumes that would otherwise support the development of non-electrified or partially electrified hubs become uneconomic. This has important implications for hub electrification,

as the absence of incremental volumes shortens asset lifetimes and weakens the business case for electrification investments. Consequently, these fields are not developed and hubs such as Skarv and Sleipner (from 2037) and Ekofisk Area (from 2049) cease operations once existing commercial production ends, removing any future incentive to electrify these facilities. Conversely, in the low case, additional yet-to-find volumes are developed, extending the productive life of many hubs by several years, including key assets such as Åsgard, Alvheim, Aasta Hansteen, Skarv, Sleipner, Gjøa, Gullfaks and Njord.

4.5 Impact of high CO_2 taxes on exploration activity

As per our analysis, 30-35% of the prospects tied to non-electrified assets are not investable under the high-case CO_2 taxes compared to only 9-12% drop-out rate for those tied to electrified hubs. Further, prospects developed via non-electrified hubs see a 25-35% decrease in post-tax value and 16-22% decrease in resources under high CO_2 taxes as compared to 5-6% and 4-6% for electrified hubs, respectively.

Table 4.3 Impact of CO_2 taxes on YTF prospects by electrification status of the hub

Change between high- and low-case CO2 taxes	Non-electrified hub	Partially electrified hub	Fully electrified hub
Change in post-tax NPV10	-25% to -35%	-17% to -25%	-5% to -6%
Change in pre-tax NPV10	-10% to -15%	-12% to -21%	-3% to -4%
Change in resources	-16% to -22%	-14% to -25%	-4% to -6%
Change in number of investable prospects	-30% to -35%	-18% to -28%	-9% to -12%

Source: Wood Mackenzie

A sustained high carbon tax scenario will raise the minimum economic field size required to justify a new development (Figure 4.1). The result of the YTF analysis also suggests that a high-carbon tax scenario could reshape the near-field exploration outlook around Norway's mature hubs. Prospects that rely on established but non-electrified infrastructure become less economically attractive with higher CO_2 costs layered onto already mature, higher-emission production.

A reduction in infrastructure-led exploration around those hubs is the obvious downside risk, particularly as geological complexity and unit costs can increase as basins mature. The Vøring Basin may be most exposed long-term where there are no electrified facilities or plans to implement in future. Prospectivity near electrified hubs in other basins is more advantaged and this may shift operators' focus on acreage capture and inventory high grading.

The impact on under-explored or frontier areas is more uncertain. Larger standalone developments are likely to have the economies of scale to absorb higher carbon costs or cost of electrification, as illustrated in the finding in Section 3. Establishing new large fields also increases the likelihood of near-field prospectivity such as is seen in the Johan Castberg area in the Barents Sea. However, any new major facility may have to factor in emission abatement solutions such as electrification or carbon capture. This scenario is not considered in the study.

In the discussion of decarbonisation initiatives in Section 3.4, it is considered that exploration success which extends the life of existing hubs could marginally improve the economics of electrification projects. However, even under a sustained high carbon tax, this effect is likely to be limited. Given the high abatement costs (NOK 5,000–7,000 per tCO2e) seen in recently cancelled projects such as Halten, Tampen, and Balder/Grane, only a few projects would realistically become viable.

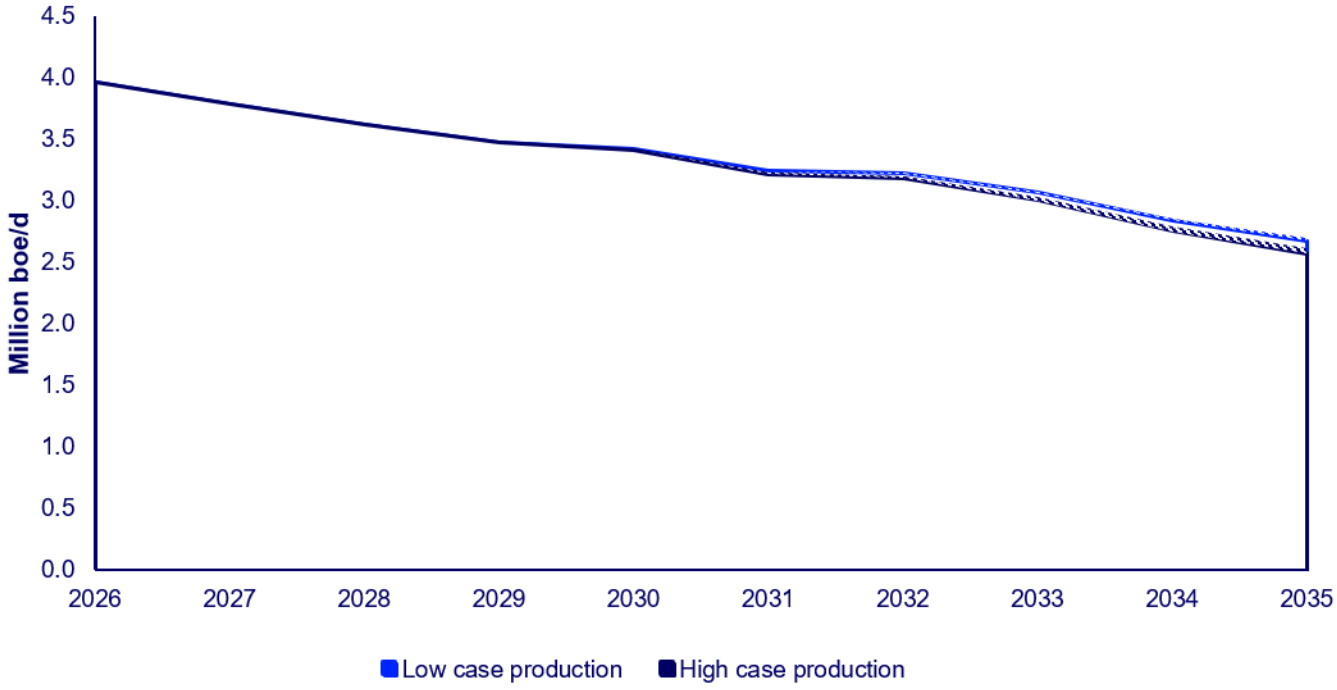
Maintaining Norway's stable fiscal framework would be an increasingly important factor as costs rise under the high-carbon cost scenario. The lower after-tax cost of exploration could continue to support upfront investment and a sustainable baseline level of exploration drilling across the NCS, which has been among the highest offshore globally in recent years.

A higher carbon tax policy may also signal a shift in broader political priorities and regulatory risk towards raising the bar around decarbonisation requirements. Proposed changes to emission reporting to include Scope 1, 2 and 3 and the benchmarks required for project approval are yet to be finalised.

The experience of the UK Continental Shelf illustrates what can happen as a result of fiscal and regulatory uncertainty. Exploration drilling was already in decline through the 2010s and fell sharply in response to the oil price crash in 2020. But activity has failed to recover following the introduction of windfall taxes (the Energy Profits Levy), tighter emissions and electrification requirements and political uncertainty that created a difficult investment climate for new exploration.

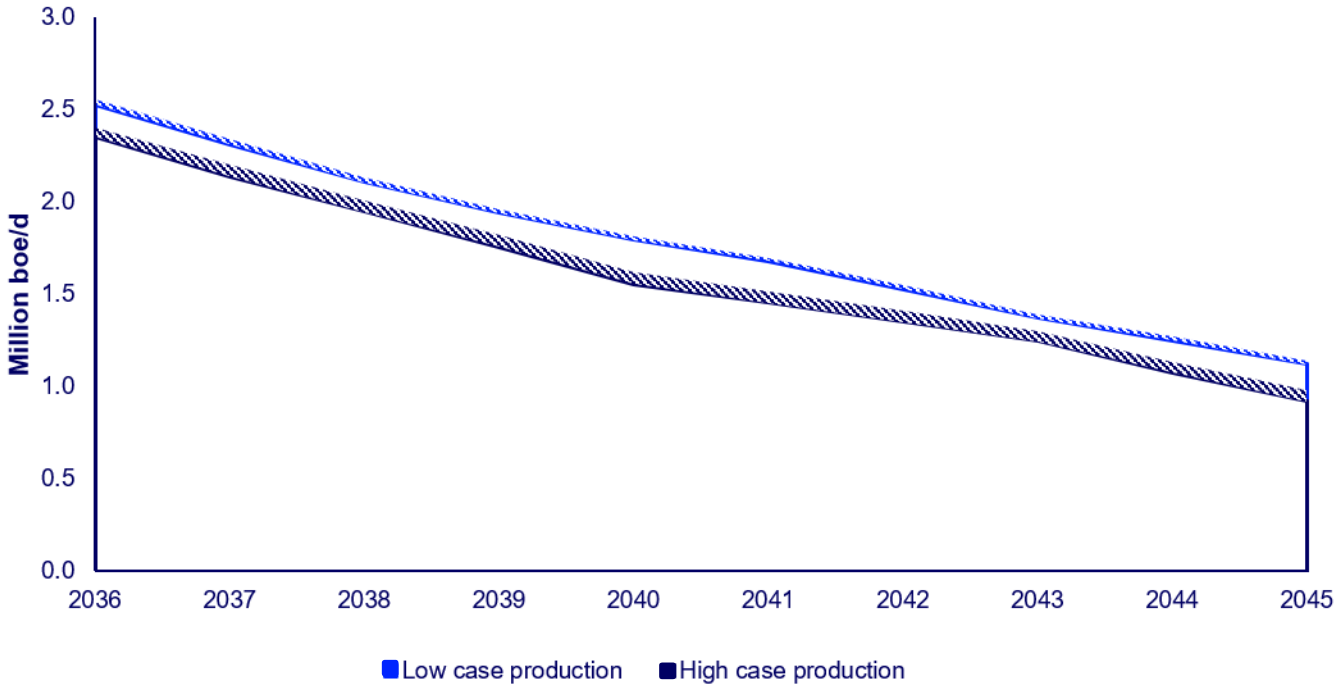
4.6 Impact on Norway's long-term production profile

Figure 4.5 Norway's commercial + yet-to-find production under high- and low-case carbon pricing scenarios (2026-2035)



Source: Wood Mackenzie. Hashed areas represent the range of uncertainty due to the emissions associated with the YTF volumes.

Figure 4.6 Norway's commercial + yet-to-find production under high- and low-case carbon pricing scenarios (2036-2045)



Source: Wood Mackenzie. Hashed areas represent the range of uncertainty due to the emissions associated with the YTF volumes.

Bringing together the volume, value and activity effects discussed across Sections 4.1 to 4.5, Figure 4.5 and Figure 4.6 show how a sustained higher carbon tax feeds through to Norway's combined commercial and yet-to-find production profile. The effect is minimal until the early 2030s where production is dominated by existing commercial fields and the additional carbon cost has a marginal impact on the operating cash flow that these fields generate and can be absorbed without changing production behaviour. The low and high case profiles are effectively identical to 2032, with combined output differing by only around 25-40 kboe/d (under 1%), and commercial production itself is barely affected throughout the decade.

The two profiles begin to diverge from the mid-2030s, driven almost entirely by production from yet-to-find resources. As set out in Sections 4.1 and 4.4, a sustained higher carbon price pushes a growing share of YTF prospects below the 15% IRR investability threshold, so that projects which would proceed in the low case fail to clear the hurdle and are not developed under the high case. This reflects the different way the carbon price affects each resource class: marginal yet-to-find prospects drop out altogether and remain undeveloped, whereas commercial fields absorb the CO2 tax as an incremental operating cost. The result is that combined output falls around 3-4% (87-105 kboe/d) short of the low case by 2035, widening to roughly 11-13% (190-240 kboe/d) by 2040. Most of this decrease in production is attributable to lower yet-to-find production, which runs some 10-16% (90-135 kboe/d) lower while production from today's commercial and economically viable fields decreases by around 11% (104 kboe/d), in the same period.

The impact on production becomes considerably more pronounced beyond 2040. By this stage, the higher carbon tax is weighing on both sources of supply: it accelerates the late-life cessation of marginal commercial barrels, and, more importantly, it renders a significant share of the yet-to-find prospects unviable that would otherwise sustain output. Combined production falls by around 155-200 kboe/d (14-18%) by 2045. The widening gap reflects the compounding nature of the effect: each prospect that fails to clear the investability threshold removes not only its own volumes but also the production tail, from the hub and other fields tied into the same hub, that it would have sustained in later years, so that the forgone output accumulates over time.

Taken together, the two charts describe a consistent and intuitive progression. A higher carbon tax has little bearing on Norway's production while the commercial base dominates supply but becomes material from the mid-2030s as it erodes the economics of new developments and is most pronounced post-2035 as a high carbon price renders an increasing share of yet-to-find prospects uneconomic. The effect is therefore felt less as a uniform reduction in output and more as a progressive thinning of the resources that would replace today's producing fields, reinforcing the conclusion of the preceding sections that the principal long-term consequence of a sustained higher carbon tax falls on Norway's future, not its current, production.

4.7 Impact of CO_2 taxes on IOGR value and resources

Norway's recovery factors rank among the highest globally, with the country's largest fields pushing the limits of absolute recovery. Operators in Norway will target further upside from both producing and new fields as they attempt to maximise recovery and value creation to slow production decline from the NCS.

Improved oil and gas recovery (IOGR) performance of Norwegian fields has improved over the last 15 years, thanks to a stable fiscal environment, continued investment in legacy fields and advanced technology deployment (see Figure 4.7).

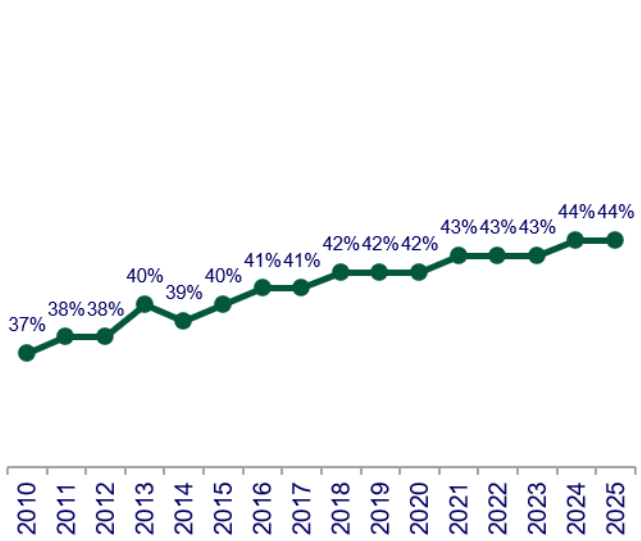
Wood Mackenzie conducted a study of the IOGR potential for Norwegian oil and gas fields; an abridged version of the study with methodology and high-level results of the recovery factor analysis is included in Appendix D. The study highlights that the upside potential from IOGR is wide and highly dependent on several geological and commercial factors. The analysis indicates the reserves growth via IOGR from existing producing fields to be 1.4 to 5.0 billion barrels for oil and 160 to 500 bcm (5.6 to 18 tcf) for gas.

For the purpose of this study, the upside from IOGR is 2.4 billion barrels of oil and 170 bcm (6 tcf) of gas, equivalent to 3.4 billion boe[21]. Increasing recovery factors from existing fields is unlikely to drive Norwegian output to new highs but would slow production decline.

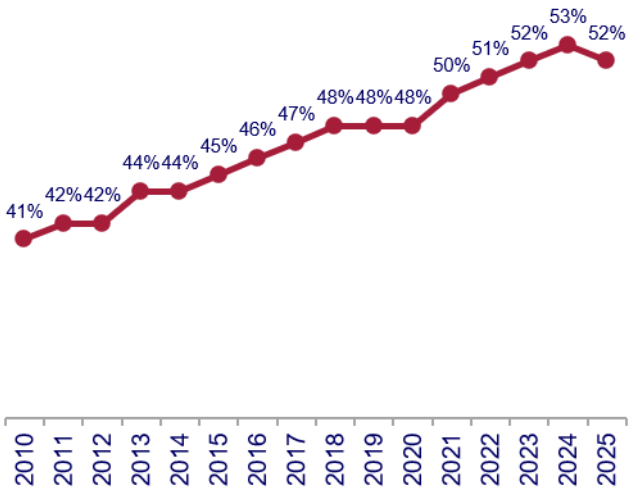
[21] *The 3.4 billion boe estimate assumes all fields achieve their P50 upside volume (median probability estimate). A subset of fields with higher recovery rates is assumed to achieve P75 upside volumes (75th percentile estimate), which raises the aggregate total modestly above a pure P50 basis. See Appendix D for detailed methodology.*

Figure 4.7 Oil and gas recovery factors on the NCS (2010-2025)

Norway's average oil recovery factor over time for legacy fields*



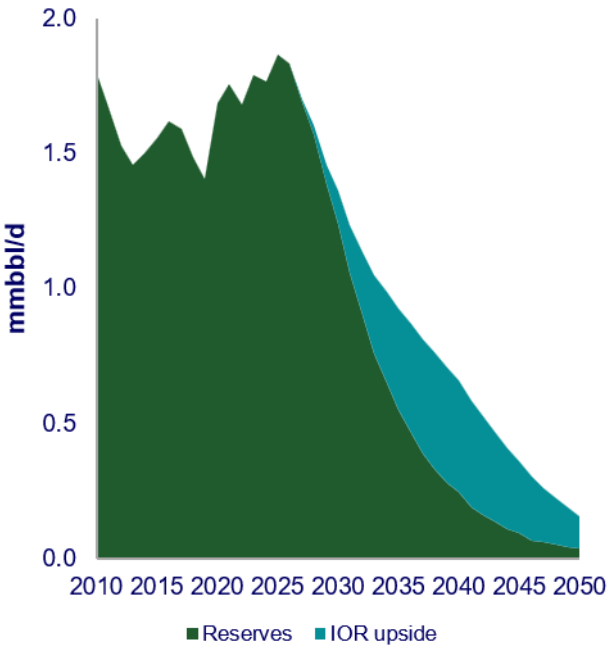
Norway's average gas recovery factor over time for legacy fields*



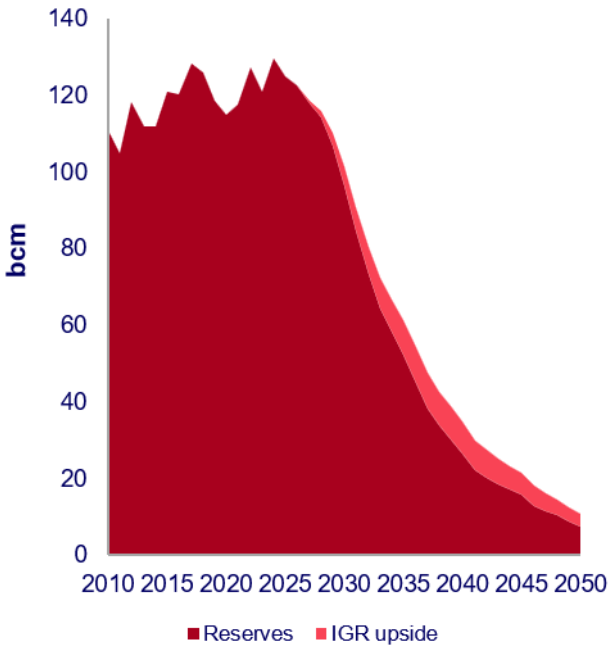
*Source: Wood Mackenzie. *Fields that have reported commercial reserves annually from 2010*

Figure 4.8 Norway production upside from improved oil and gas recovery

Oil production (2010-2050)



Gas production (2010-2050)



Source: Wood Mackenzie. Reserves include existing producing fields and future plans. Excludes resources from discoveries and yet-to-find.

The impact of carbon costs on IOGR for the purposes of this analysis is indicative. A weighted average NPV10/boe (pre- and post-tax) has been calculated for the low- and high-case carbon tax based on the results of the yet-to-find analyses. The weighted average has been used to account for different cost and production profiles that will occur under varying improved recovery techniques and development concepts. Given the timing, production profile and energy intensity of the IOGR volumes, we assume that the impact of carbon tax will mirror the YTF analyses as they will be subject to a higher CO_2 tax while meeting an investability threshold of 15% IRR.

The low and high range NPV10/boe has then been applied to the assumed 3.4 billion boe resources from IOGR. The results are outlined in Table 4.4, in which the high case results in an 8.7-14% drop in pre-tax value versus the low case. The decrease in pre-tax and post-tax NPV also implies a 7% to 15% reduction in total government take as a significant number of IOGR projects will fail to meet the investability criteria in the high-case scenario as compared to the low-case.

A similar indicative analysis can be used to illustrate the potential impact on total IOGR resources. The average decrease in reserves and resources between the low- and high-case scenarios is expected to be between 12-19%. A similar decline in IOGR resources would be equivalent to ~400-640 mmboe.

Table 4.4 Impact of low and high NPV10/boe on the value and volume of IOGR resources

	Low case	High case	Change %	Change Abs.
Pre-tax NPV10/boe (US$/boe)	6.05	5.2-5.5		
Pre-tax NPV10 (US$ billion)	20.6	17.7-18.8	-8.7% to -14%	1.8-2.9
Post-tax NPV10/boe (US$/boe)	1.0	0.84-0.94		
Post-tax NPV10 (US$ billion)	3.5	2.9-3.2	-7% to -17%	0.2-0.6
Government take (from profit-based taxes, CO2 tax and SDFI stake) (US$ billion)	17.1	14.4-15.9	-7% to -15%	1.2-2.6
Resources (million boe)	3,400	2,763-2,983	-12% to -19%	416-637

Source: Wood Mackenzie. Total government take assumes an average SDFI stake of 28%. Refer footnote 20 for further details.

This directional analysis is intended only to illustrate the potential loss in value and resources across the IOGR upside. The variance is likely to be wide depending on multiple factors, including, but not limited to:

- Timing of realised upside: the later production is brought onstream the higher CO_2 it is exposed to under the high case.
- End-of-life operating costs: where incremental production must take on a higher proportion of operating costs if a host field/facility is deemed uneconomic. This would erode value under the low and high case scenarios, particularly in areas where remaining prospectivity is low, and yet-to-find volumes cannot lower the burden of CO_2 costs at existing fields.
- Electrification: upside at non-electrified fields has a greater exposure to higher carbon costs, potentially reducing the viability of upside investment around those hubs. A fully or partially electrified facility will benefit most with limited value and resource destruction under a high-case scenario as seen in the analysis done in Sections 3 and 4.
- Emissions: It is assumed that IOGR would generate incremental emissions across the NCS. But it will vary from field to field based on several factors such as the reservoir drive mechanism, production, processing and power requirements, hydrocarbon quality and the age of infrastructure.

5 Case studies

5.1 Summary

The study includes two case studies to illustrate the effect the low- and high-case carbon price scenarios have on existing infrastructure and project economics.

A non-electrified and partially electrified facility and surrounding hub have been selected to show the range of outcome between a high- and low- carbon emitting facility.

The case studies selected include:

- Non-electrified: Skarv Area in the Norwegian Sea
- Partially electrified: Gjøa Area in the Northern North Sea

The analysis reflects Wood Mackenzie's base case as of April 2026. Changes or inclusion of assets after this time are not included.

Table 5.1 and Table 5.2 summarise the analysis of the commercial and yet-to-find scenarios at each hub respectively. The analysis of the two hubs is broadly consistent with the findings reported at the NCS level, though there are nuances due to the scale, timing and asset profiles between the two hubs.

Table 5.1 Summary of commercial and economically viable fields

	Skarv Area				Gjøa Area			
	Low case	High case	Change	% change	Low case	High case	Change	% change
Pre-tax NPV10 (US$ billion)	11.4	11.1	-0.3	-2.2	8.0	7.8	-0.2	-2.3
Post-tax NPV10 (US$ billion)	2.1	1.9	-0.2	-8.6	1.0	0.9	-0.1	-4.4
Reserves (billion boe)	0.38	0.37	-0.01	-3.1	0.29	0.28	-0.01	-5.0
Field life	2038	2036	-1.7	-0.1	2037	2035	-2.1	-0.1

Source: Wood Mackenzie

Table 5.2 Summary of yet-to-find resources

	Skarv Area				Gjøa Area			
	Low case	High case	Change	% change	Low case	High case	Change	% change
Pre-tax NPV10 (US$ billion)	0.4	0.0	0.4	-100	1.0	0.9	-0.1	-11.7
Post-tax NPV10 (US$ billion)	0.1	0.0	-0.1	-100	0.2	0.2	-0.0	-22.0
Reserves (billion boe)	0.08	0.00	-0.08	-100	0.13	0.10	-0.03	-22.2
IRR	17%	7%	-10%		19%	18%	-1%	

Source: Wood Mackenzie

5.2 Example impact of emission sharing – Skarv Area only

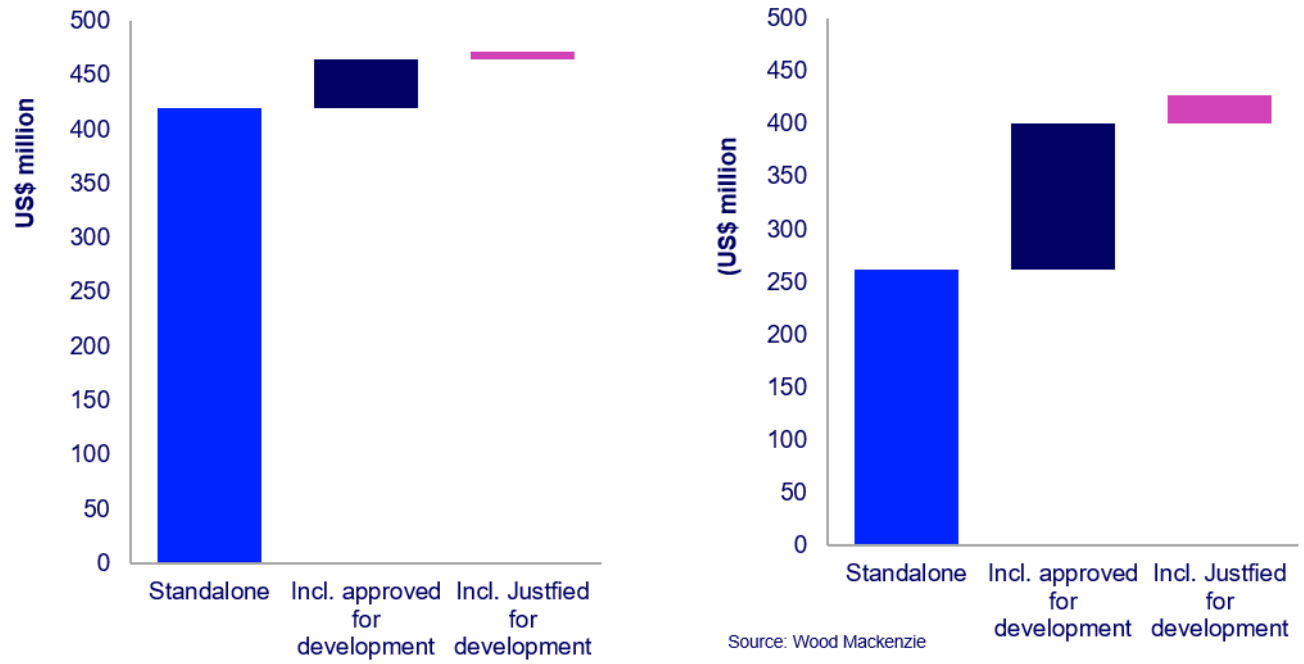
This analysis is illustrative of how the post-tax economics of host fields are improved by sharing emissions costs with satellite fields under the low- and high-case carbon tax scenarios. It is only performed on the Skarv Area as no other fields use the host FPSO at the time of the study. Gjøa benefits from three fields that already use its platform for processing and export. Field economics also benefit from operating cost sharing which the Skarv Area does not.

Under both carbon price scenarios, the value of the Skarv field increases when new fields are introduced (see Figure 5.1). This is expected as the host field's share of emission costs is lowered as costs are distributed between new fields on a production throughput basis.

In the high-case scenario, the addition of the Skarv Satellites project (Approved for development) increases the remaining NPV10 by 52%. The addition of Storjo and Adriana/Sabina (Justified for development) adds a further 7%. The impact under the low-case scenario is lower as emission costs account for a lower share of overall operating costs. The same benefit would be realised at an electrified host, but the impact is lower given the lower emission and carbon costs associated with those facilities.

The example also illustrates that near-field developments that use existing infrastructure can be important contributors to improving operating cash flow and potentially incentivising new investment to extend the life or improve recovery of the host field. The challenge for any tie-back candidate is its ability to cover this allocated cost, particularly where they become the dominant producer.

Figure 5.1 Impact of emission sharing on the Skarv host field under low- and high-case carbon tax scenarios



Source: Wood Mackenzie

5.3 Skarv Area

5.3.1 Summary

The Skarv Area is in the northern part of the Norwegian Sea, approximately 50 kilometres north of the Heidrun field. The area is operated by Aker BP and has been developed with the production and storage vessel, Skarv FPSO, for processing, storage and export. Oil is exported by tankers, and rich gas is transported to the Kårstø terminal via the Åsgard Transport System (ATS).

The FPSO acts as a host for multiple fields, which have been developed via subsea infrastructure. The Skarv Unit includes the development of the Skarv, Idun, Tilje, Ærfugl and Gråsel fields. Initially discovered in 1998, the Plan of Development and Operation (PDO) was approved in 2007 and put into production at the start of 2013. The unit is connected to 10 subsea templates from the various structures.

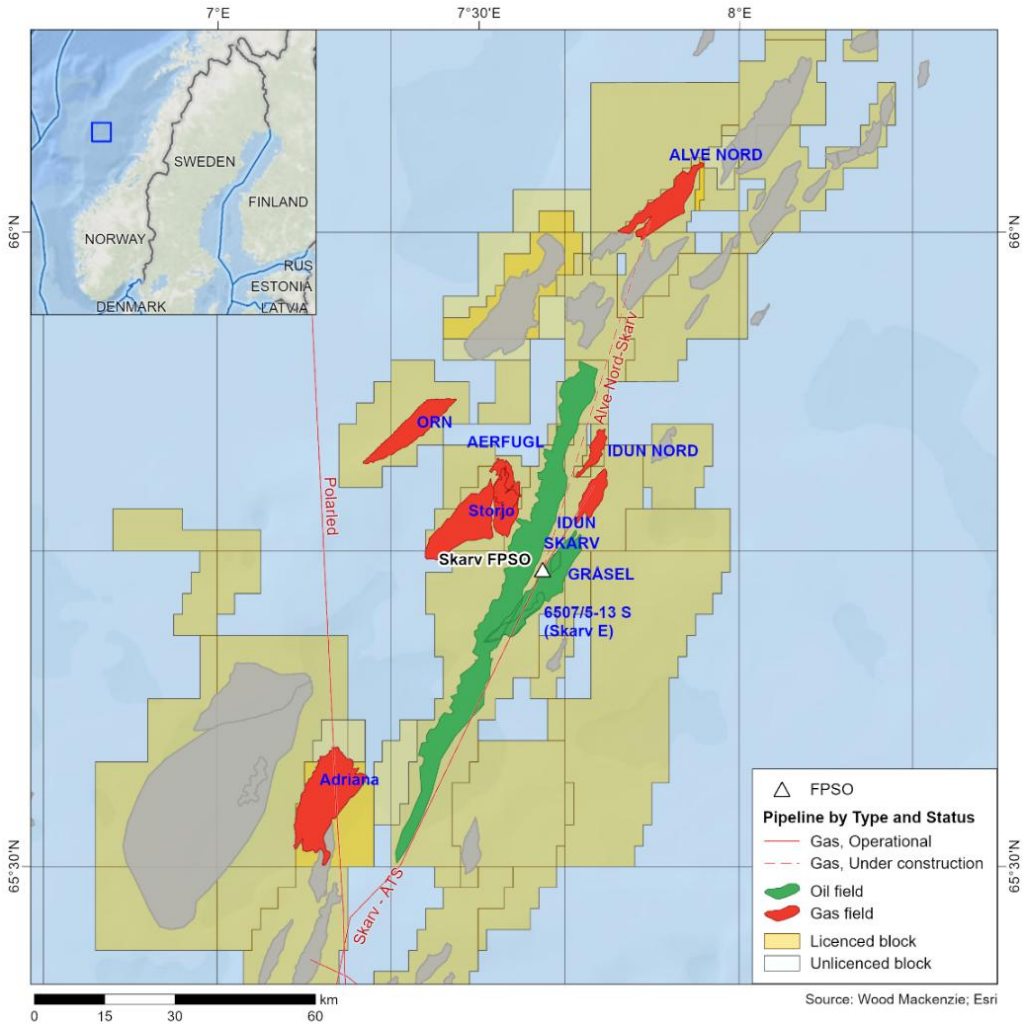
Oil production is in decline though gas exports increased with gas injection permanently shut down in 2025 after gradual reductions from 2022. Wood Mackenzie assumes production will cease in the mid-2030s under its April 2026 base case, but the operator is working to extend operations until 2040. New subsea tie-back fields will be important to achieve this and improve operational efficiency via increased production throughput. The Skarv Unit will also receive tariff payments for use of its facilities (a future opex share is not assumed) and emissions will be distributed across all fields, easing the burden on older fields.

The largest ongoing investment in the area is the Skarv Satellites project. The project consists of the development of the Idun Nord (gas/condensate), Alve Nord (oil and gas) and Ørn (gas and condensate) fields. All are being developed as subsea tiebacks to the Skarv FPSO. The development of the three discoveries is coordinated by one project team to improve project and cost efficiencies.

A final investment decision was taken in late 2022 and government approval was granted in June 2023. Production is expected to start in Q3 2026, approximately one year ahead of the original schedule. The development phase qualified for Norway's temporary tax amendments which were introduced in response to the Covid-19 pandemic.

The Storjo (gas) and Adriana/Sabina (gas/condensate) projects are included in the analysis of the Skarv Area. Reserves are classed as Justified for Development under the Petroleum Resources Management System (PRMS). The projects passed Decision Gate 1 (Concept Selection) in late 2025. Both will use new subsea infrastructure tied back to the Skarv FPSO. Production from both projects could start as early as Q4 2029.

Figure 5.2 Map of Skarv Area



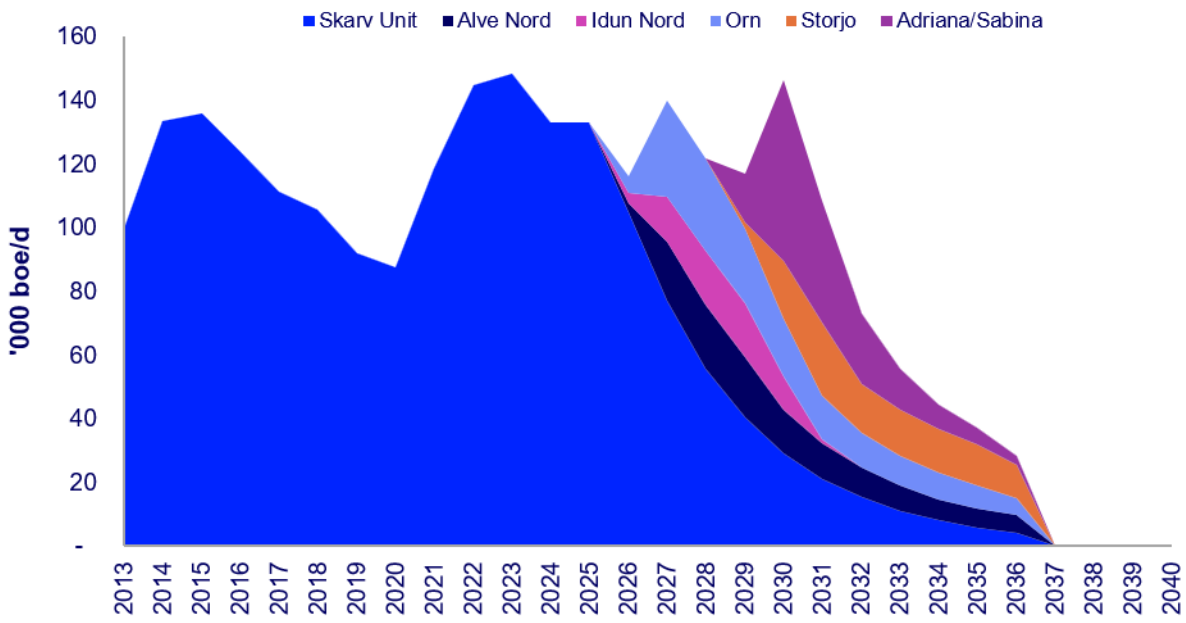
Source: Wood Mackenzie

Table 5.3 Skarv Area summary

Field	Status	Operator	Start-up year	Concept	Total Reserves (mmboe)	Remaining Reserves (mmboe)
Skarv	On production	Aker BP	2013	FPSO	711	138
Alve Nord	Approved for development	Aker BP	2026	Subsea	44	44
Idun Nord	Approved for development	Aker BP	2026	Subsea	23	23
Ørn	Approved for development	Aker BP	2026	Subsea	60	60
Storjo	Justified for development	Aker BP	2029	Subsea	40	40
Adriana/Sabina	Justified for development	Harbour Energy	2029	Subsea	60	60

Source: Wood Mackenzie. Remaining reserves as of 1 January 2026. COP = cessation of production. Our analysis excludes Ærfugl Nord as no remaining reserves are reported, contingent resource, Lunde and Newt discoveries and proposed development of Skarv E and Ærfugl Phase 3.

Figure 5.3 Skarv Area production profile (2013-2040)



Source: Wood Mackenzie base case production profile as of April 2026.

5.3.2 Yet-to-find prospective resources

The study includes estimates of yet-to-find resources based on Wood Mackenzie's Vøring Basin analysis (see Appendix A). The Vøring Basin has an estimated 1.5 billion barrels of oil equivalent (boe) of yet-to-find resources. Of this total, 120 million boe of future exploration success has been allocated as near-field discoveries that could be developed as subsea tie-backs to the Skarv FPSO for production, processing and export.

The yet-to-find analysis includes model field discovery sizes of 10 and 20 million boe based on the maturity of the area, recent exploration results and the volume of yet-to-find resources. The year of discovery and prospect size are shown in Table 5.4.

Table 5.4 Phasing of yet-to-find prospective discoveries

Model discovery size (mmboe)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
10	0	0	0	0	1	0	1	0	0	0	1	0	1	0	0
20	0	0	1	0	0	1	0	0	1	0	0	1	0	0	0
Total	**0**	**0**	**20**	**0**	**10**	**20**	**10**	**0**	**20**	**0**	**10**	**20**	**10**	**0**	**0**

Source: Wood Mackenzie

5.3.3 Emissions and emission costs

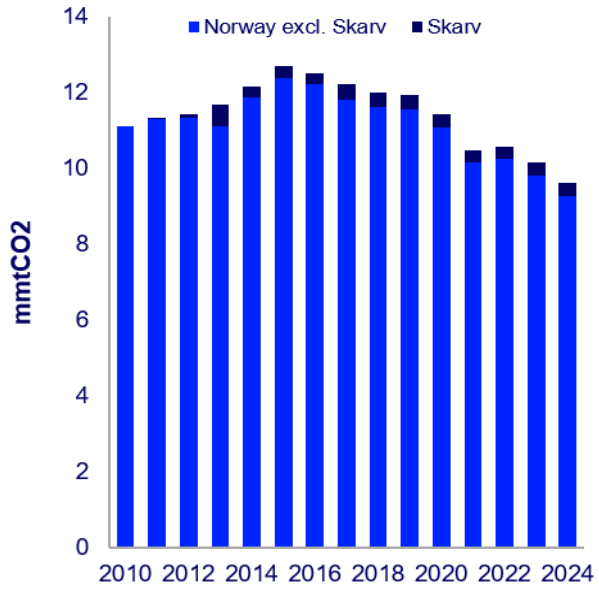
The Skarv field emitted 370 $ktCO_2$ in 2024, equivalent to approximately 4% of total emissions across the NCS, making it a top 10 emitter. A CO_2 intensity of 7.6 tCO_2/kboe was higher than the 6.3 tCO_2/kboe average on the NCS (excluding methane). We estimate that emissions will rise incrementally until 2029 as development activity and new production is added before going into decline (see Figure 5.4).

Most of the emissions generated at Skarv are associated with the FPSO. Electricity is generated by gas turbines, and the power consumption is high due to necessary compression work on the topside to export the gas approximately 800 kilometres to the Kårstø process terminal. Most of the CO_2 emissions come from the turbine exhaust system on the FPSO. The total emission footprint also includes smaller and occasional sources such as safety flaring, gas venting during maintenance, offloading and other marine activity on the field (e.g. drilling rigs, mooring ships and subsea inspection vessels).

Electrification via shore power has been considered but rejected because it is not economically viable for Skarv. Wind power has been considered but found to be inappropriate due to economic conditions and lifetime assessments. However, energy efficiency measures have been implemented that have contributed to reduced emissions, including measures for more efficient operation of existing gas turbines.

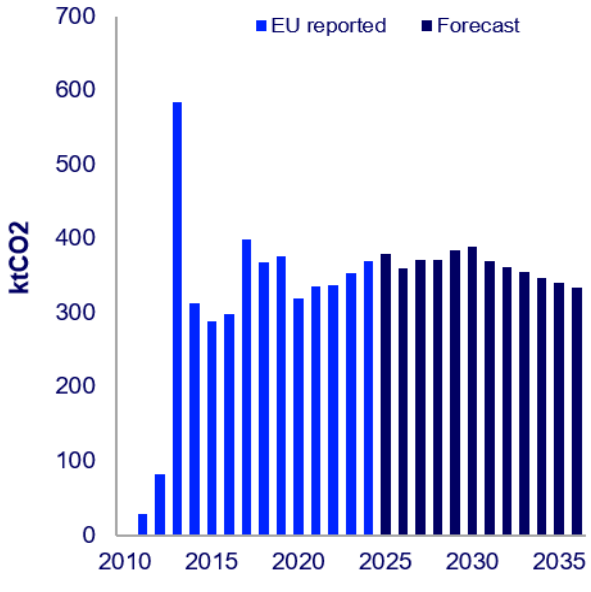
Figure 5.4 Absolute NCS and Skarv Area CO_2 emissions

Norway upstream fields CO_2 emissions (2010-2024)



*Annual verified emissions from the Union Registry. 2025 data not available at time analysis commenced. Excludes onshore facilities.

Skarv Area CO_2 emissions: reported and forecast



*Reported emissions up to and including 2024. 2025 data not available at the time analysis commenced.

Source: Wood Mackenzie and EU

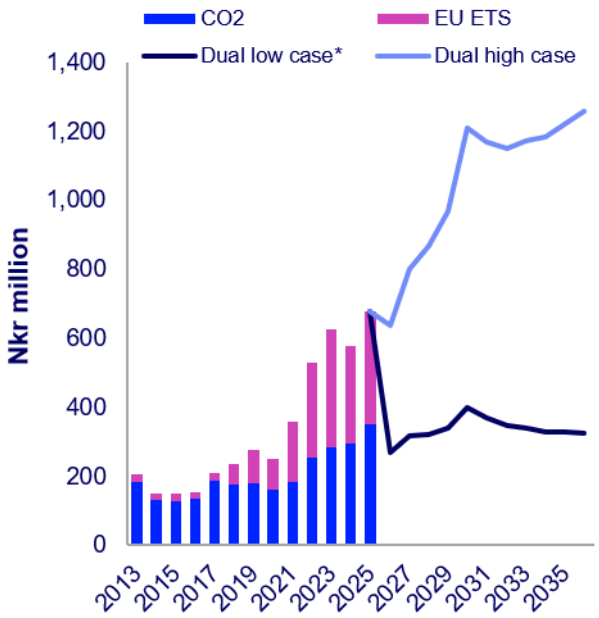
The combined Norway CO_2 and EU ETS emission costs increased 60% between 2021 and 2024, compared to a 10% increase in reported CO_2 emissions over the same period. The increase was driven by rising EU ETS prices, Norway's dual carbon price plan and a weaker Norwegian Krone against the Euro and US dollar.

Total carbon emission costs increased as a proportion of overall operating costs as a result. Emission costs as a percentage of overall operating costs rose from around 15% in 2015 to nearly 35% in 2024 (see Figure 5.5). This is equivalent to around NOK 12/boe or US$1.1/boe (nominal). Emission and operating cost reduction are therefore important to ensure the field covers its costs, maximises recovery and extends field life.

The Skarv field will also benefit from the start-up of new fields in the area. The Skarv FPSO will process and export all the hydrocarbons produced so production and processing emissions will be distributed on a production throughput basis at the host. New satellite fields will therefore take on a share of the overall CO_2 costs. While this will benefit the host field, high carbon costs may pose a risk to future project economics and ultimate recoverable reserves and resources.

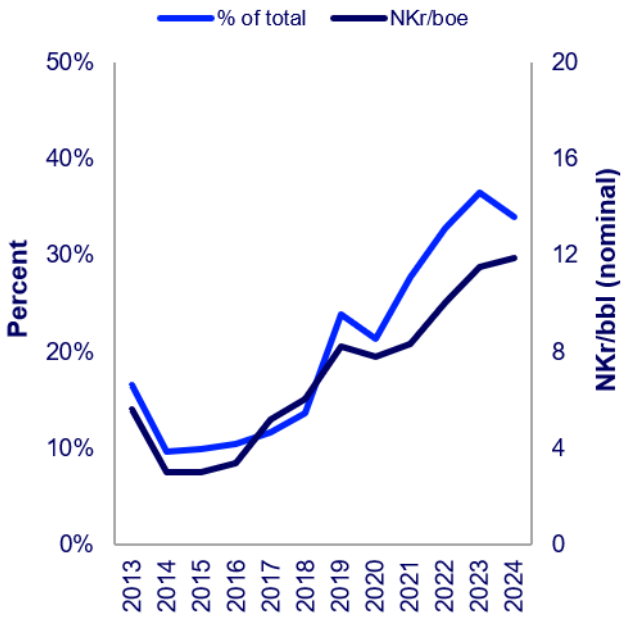
Figure 5.5 Skarv Area CO_2 emission costs

Skarv Area CO_2 costs reported and scenario forecast



NOD reported CO2 emission cost. *Dual low case excludes CO_2 tax, EU ETS only. **Wood Mackenzie calculated EU ETS costs. Nominal to 2025 and 2026 real terms from 2026 onwards. For Dual price case assumptions see Appendix A.

Skarv field CO_2 costs as share of total and unit opex



Source: Wood Mackenzie

Reported CO2 and Wood Mackenzie estimate EU ETS costs as a percentage of total reported operating costs in nominal terms. Excludes G&A and transportation and tariff assumptions.

Source: Wood Mackenzie

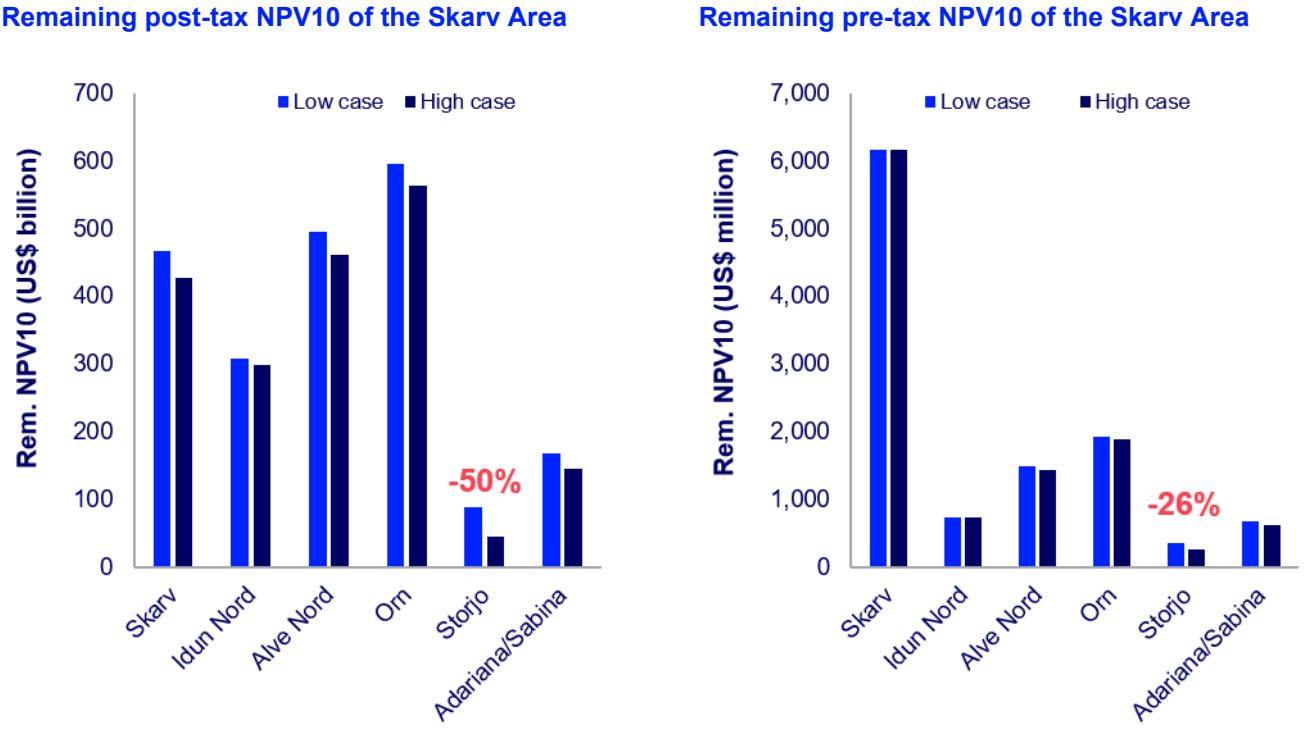
5.3.4 Scenario analysis

Low- and high-case carbon tax impact on the Skarv Area

Economic analysis of the Skarv Area applies the same methodology as Section 3 and Section 4 where the effects of the low- and high-case carbon tax scenarios are illustrated.

The results of the scenario modelling presented in Figure 5.6 show that a higher carbon tax reduces NPV10 in both pre- and post-tax cases. This is expected, since a higher CO_2 tax increases opex, lowering net cash flows. Since the CO_2 tax is tax-deductible, its net impact is partially offset by lower taxable income.

Figure 5.6 Impact of low- and high-case carbon tax scenarios on NPV10 value of the Skarv Area



Source: Wood Mackenzie

The impact on post-tax NPV10 is higher compared with the pre-tax impact. The average present value lost rises from 2.2% (pre-tax) to 8.6% (post-tax). There is a range across each of the fields, but the high case scenario has a greater impact at Storjo and Adriana/Sabina where nearly 100% of production is expected post-2030. This is when CO_2 prices rise quickly under the high-case scenario and have a greater impact on project costs. Figure 5.7 illustrates the proportion of CO_2 and EU ETS costs as percentage of overall operating costs.

The CO_2 tax scenarios also impact remaining reserves and field life. Approximately 12 mmboe or 3% of hub remaining reserves are lost between the low and high carbon tax scenarios as field life is expected to cease 1.7 years earlier on average.

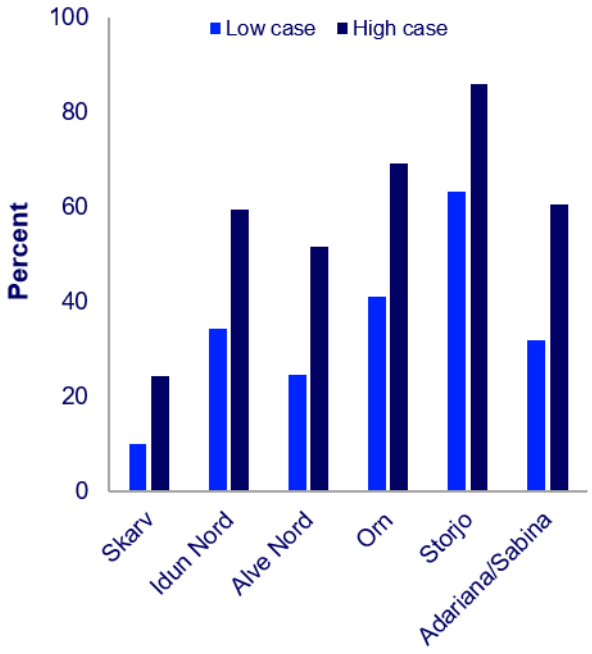
Storjo is an outlier within the hub with a 26% and 50% reduction in pre- and post-tax NPV10 respectively between the low and high carbon tax scenarios. The project's internal rate of return (IRR) is also reduced by around five percentage points from 23% to 18% from the low to high case scenario (see Figure 5.7).

The Storjo result is due to the assumed project timing and production profile. The Storjo base case accounts for 11% of total production across the hub between 2029 and 2036 but nearly 25% of total combined CO_2 and EU ETS costs under the high-case carbon tax scenario. A higher proportion of emission costs are allocated due to a flatter production profile as CO_2 costs rise during the 2030s. The result is over 80% of operating costs attributable to emissions allocation.

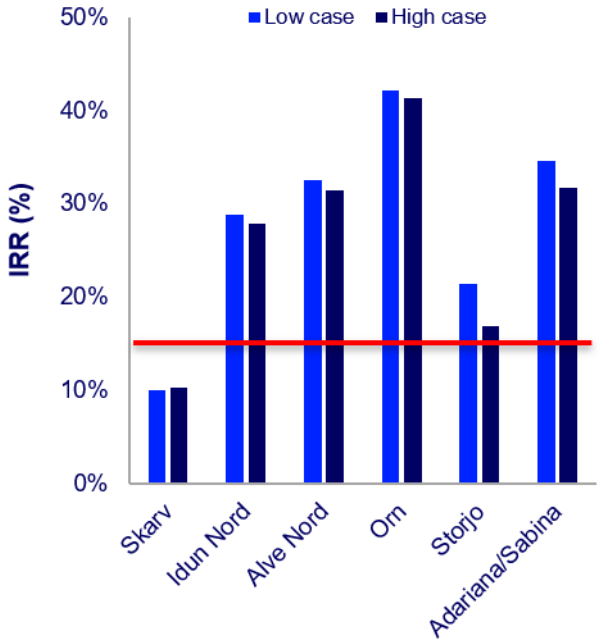
The project IRR is still above an assumed investment hurdle rate of 15% under the high carbon tax scenario. But it could be considered marginal and a downside cost and/or reserves scenario could push project economics below an investment hurdle rate. In this case, the area would lose 43 mmboe, or 16% of commercial hub reserves. The impact on the remainder of the hub would be modest with a 2.5% decrease in post-tax NPV10 because of higher allocated emissions. The pre-tax NPV10 on the hub is unchanged because incremental emissions from Storjo are assumed to be negligible.

Figure 5.7 Impact of low- and high-case carbon tax scenarios on Opex and IRR

Scenario emissions cost as % of Opex (2026-2036)



Low vs. high case full-field internal rate of return



Source: Wood Mackenzie

This result highlights that each hub is unique but the analysis of the whole NCS illustrates that higher carbon taxes can reduce the economic viability of marginal production towards the end of field life. Some production that would be profitable under a low carbon tax case becomes uneconomic **under the high-case scenario as a result.**

Electrification scenario

The electrification of the Skarv Area has been rejected in the past. However, to illustrate the possible impact of electrification on the low- and high-case carbon prices, a simplified electrification scenario has been created. The basic assumptions for a fully powered from shore concept are outlined in Table 5.5. It is assumed that all six fields would contribute to the upfront capital investment.

Table 5.5 Skarv Area electrification assumptions

Total CO2 savings (ktonnes)	Cost per tonne (NOK)	Total capex (NOK million)	Power (MW)	First power (year)
3,000	5,000	15,000	50	2030

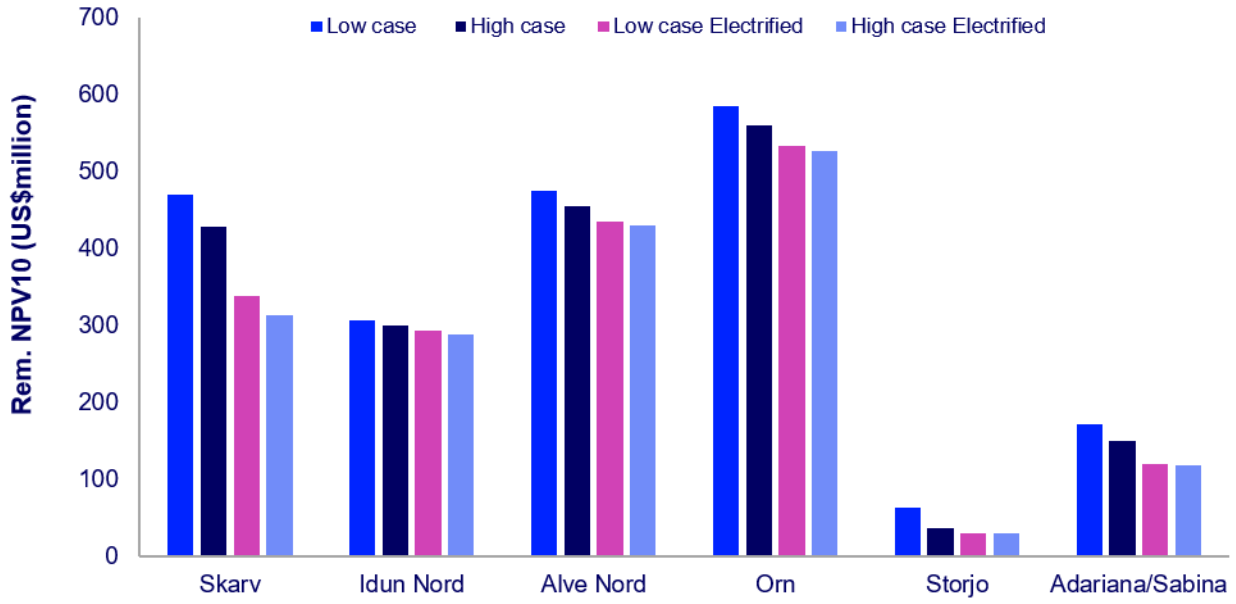
Source: Wood Mackenzie

The addition of electrification under these assumptions destroys value under the low- and high-case scenarios as expected. The difference between the low- and high-case electrified scenarios is minimal given the short period of CO_2 savings assumed.

The conclusion in this example is that it is not economically viable for fields that are expected to cease within the next decade to consider electrification. There could be a point at which electrification becomes viable if IOGR and/or yet-to-find prospective resources can prolong the life of the host facility into the 2040s. However, the operator would need certainty of the resource additions before any new electrification investment could be considered. Final investment decisions would need to be made within the same time frame to maximise the potential economic benefit of reducing future emissions from the hub.

In addition, a more attractive cost environment and political backing for prioritising new electrification projects would be required as outlined in Section 3.5.

Figure 5.8 Impact of low- and high-case carbon tax scenarios on post-tax remaining NPV10



Source: Wood Mackenzie

Skarv Area yet-to-find analysis

The yet-to-find analysis is considered at the hub level, not individual model prospects. The Skarv Area study includes eight prospects with a combined prospective resource of 120 million barrels of oil equivalent, with a liquid and gas split of 60:40.

The results of the scenario modelling show that higher carbon taxes have a greater effect on Norway's yet-to-find resources compared to its commercial reserves. Under the low case, the eight modelled prospects have a combined post-tax NPV10 of US$73 million (NOK 706 million). This falls to US$60 million (NOK 580 million) excluding prospects that don't make a 15% return. All prospects have a negative NPV10 under the high-case carbon tax scenario with a combined value of US$-26 million (NOK -251 million) (Figure 5.9).

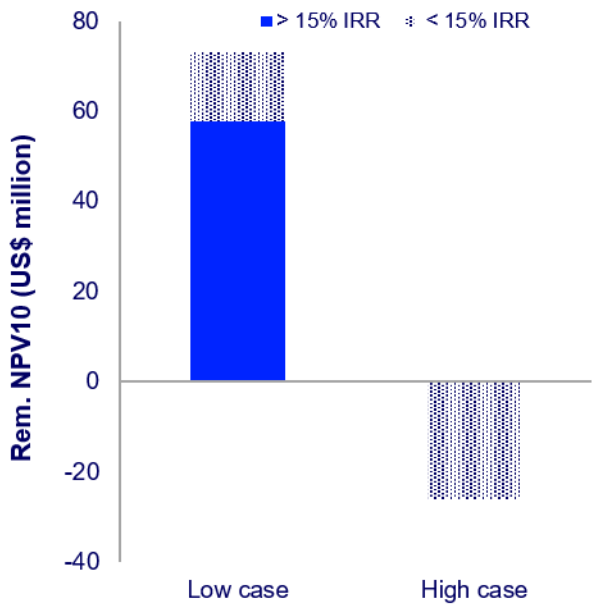
A high carbon price scenario renders all the yet-to-find resources sub-economic or un-investable with post-tax IRRs of less than 15%. The operating life of the Skarv hub would cease in 2036 in line with the result of the commercial analysis in Section 2. Future exploration upside, investment and tax revenues to the state would be lost. In contrast, emissions from the NCS would decline through the earlier cessation of the Skarv FPSO.

Under the low carbon price scenario, the four 20 mmboe prospects meet the investable threshold with IRRs over 15%, equivalent to 80 mmboe of upside resources. The 10 mmboe prospects fail to generate a post-tax IRR greater than 15% (pre-tax IRRs are marginally economic). The prospect size is not big enough to carry the upfront investment, operating costs and taxes, even without the additional carbon tax burden. This is equivalent to 40 mmboe of the 120 mmboe resources modelled. While on a standalone basis these prospects are not viable, cluster developments of smaller prospects could make these prospects economic depending on proximity and distance to the host facility. We don't consider this scenario in this study.

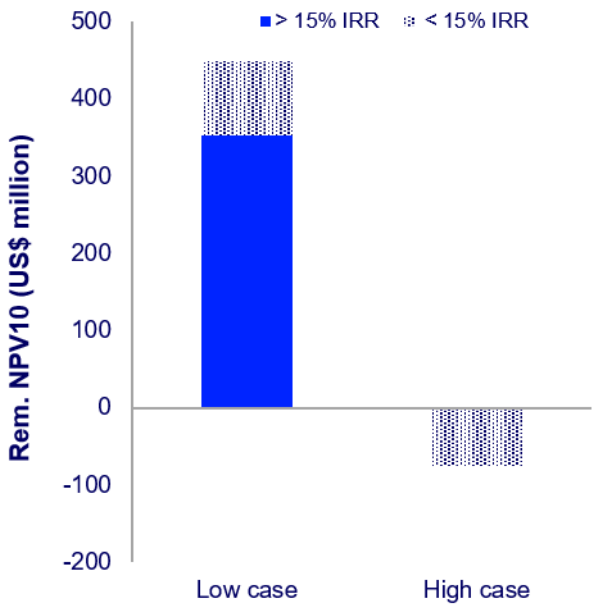
The loss of 40 mmboe and all 120 mmboe yet-to-find resources under the low and high carbon price scenarios has a material impact on potential production from the Skarv Area illustrated in Figure 5.10.

Figure 5.9 Impact of low- and high-case carbon tax scenarios on NPV10 value of Skarv Area YTF

Remaining post-tax NPV10 of the Skarv Area YTF



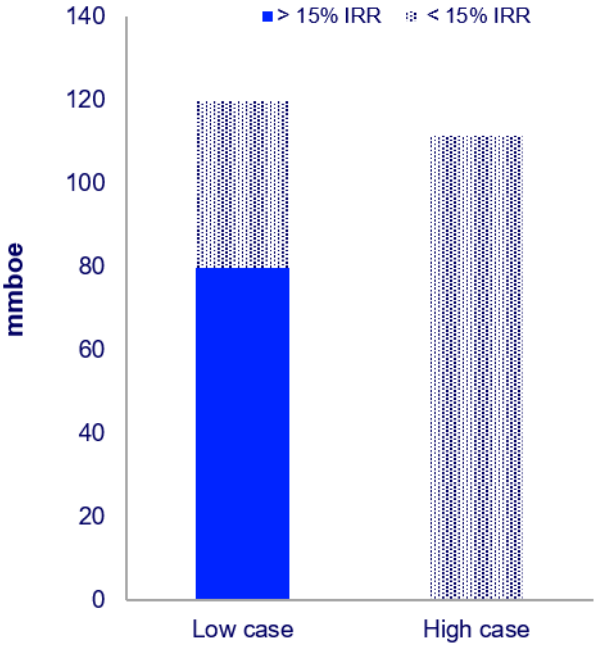
Remaining pre-tax NPV10 of the Skarv Area YTF



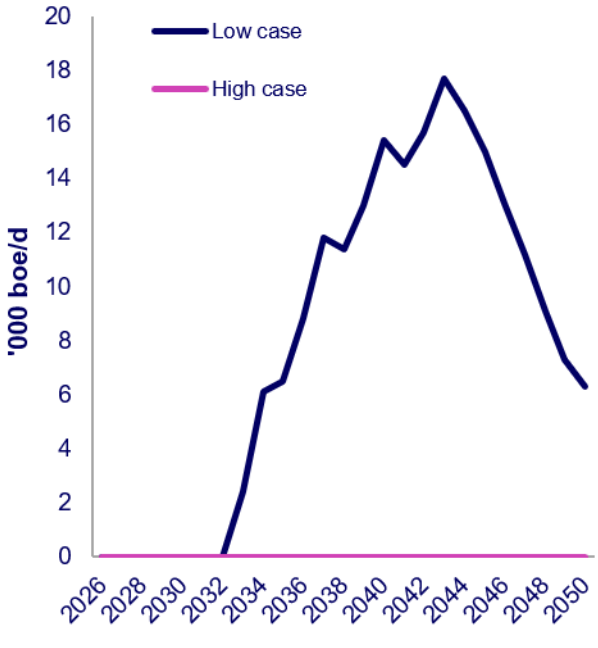
Source: Wood Mackenzie. Hashed areas represent NPV10 that is below a 15% IRR investable hurdle rate. Pre-tax NPV includes deduction of CO_2 taxes which are treated as operating costs.

Figure 5.10 Impact of low- and high-case carbon tax scenarios on Skarv Area YTF resources and production

Skarv Area YTF resources by investment threshold



Skarv Area YTF production (2026-2050)



Source: Wood Mackenzie. Hashed areas represent NPV10 that is below a 15% IRR investable hurdle rate. Pre-tax NPV includes deduction of CO2 taxes which are treated as operating costs. Skarv Area YTF production does not assume any extension of production from host or satellite fields – See footnote 18.

5.4 Gjøa Area

5.4.1 Summary

The Gjøa Area is in the northern part of the North Sea, approximately 50 kilometres northeast of the Troll field. The area includes the Gjøa field, several production fields developed via subsea infrastructure and planned projects.

Gjøa was discovered by Norsk Hydro in 1989 and is now operated by Vår Energi. The PDO was approved in 2007 and production started in 2010. The field has been developed with a semi-submersible production facility linked to five subsea templates. There have been subsequent phases of development on the field. The original development included the partial electrification of the facility with power from shore.

Gas is exported via the Far North Liquids and Associated Gas System (FLAGS) to the St. Fergus terminal in the UK, and liquids are exported via the Troll Oil II Pipeline to the Mongstad facility.

The Gjøa platform is host to the Vega, Duva and Nova fields. All three fields have been developed via subsea infrastructure and share the operating costs for use of the Gjøa production and export facility.

- Vega was discovered in 1981, 30 kilometres west of Gjøa. The PDO was approved in 2007 and production started in 2010. The field has been developed with three subsea templates tied to the Gjøa production and processing facility.

- Duva was discovered in 2016 six kilometres northeast of the Gjøa field. The PDO was approved in 2019 and production started in 2021. The field has been developed with a single subsea template tied back to the Gjøa platform.

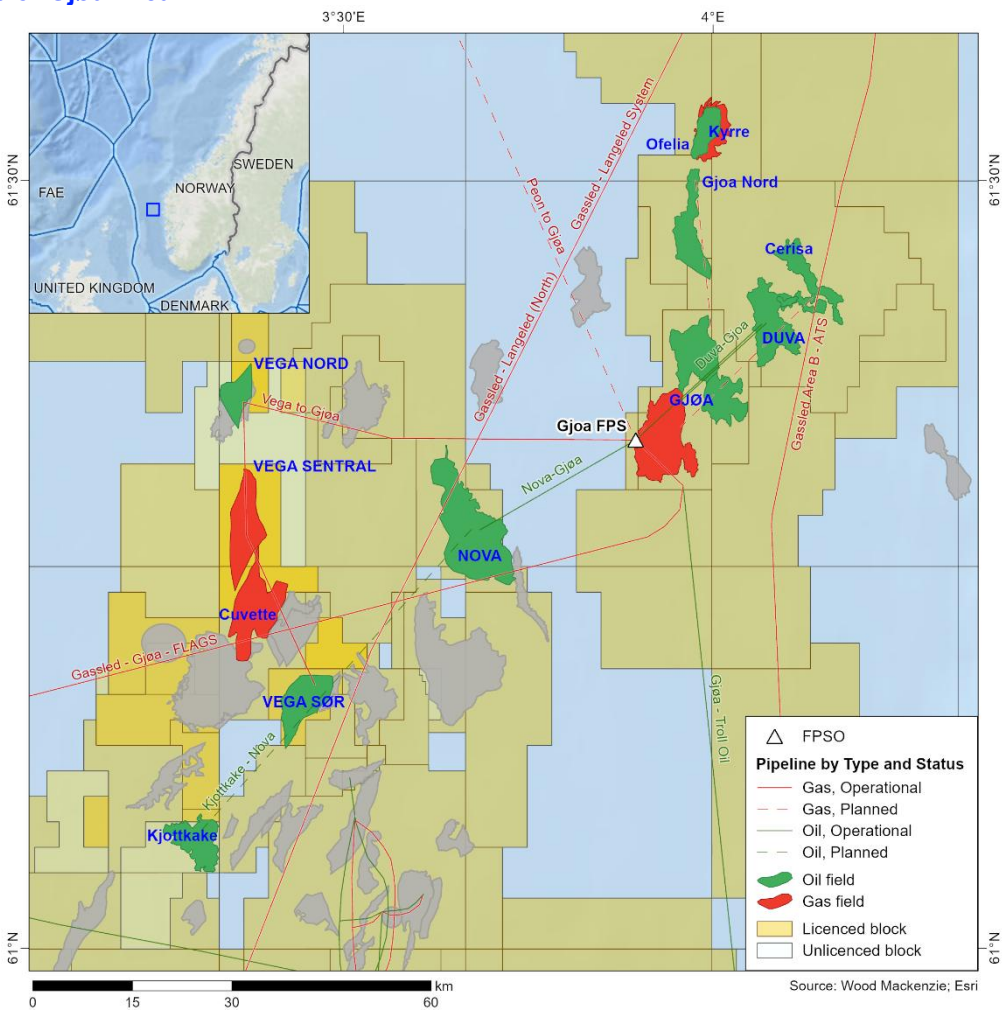
- Nova was discovered in 2012, 20 kilometres southwest of the Gjøa field. The PDO was approved in 2018 and production started in 2022. The development consists of two subsea templates tied back to the Gjøa platform.

Vår Energi submitted development plans for the Gjøa Satellites project in June 2026. The project consists of the development of the Ofelia, Gjøa Nord and Cerisa fields. All are being developed as subsea tiebacks to the Gjøa platform. We assume production will start in 2028 but could be as early as 2027 (see Table 5.6).

The Kjøttkake and Cuvette projects are also included in the Gjøa Area case study. Reserves are classed as Justified for Development under the Petroleum Resources Management System (PRMS). Development plans are expected to be submitted by the end of 2026, and both projects will use new subsea infrastructure tied back to the Gjøa platform.

The study assumes new production throughput and tariff revenues would improve project economics and extend the life of the Gjøa platform to the mid-2030s. However, the operator is targeting life extension to around 2040 and possibly beyond. Delivery would further strengthen the platform for future tie-ins and unlock additional exploration value across the Greater Gjøa Area. We assume the fields will take a share of the operating and carbon costs at the host platform from 2028.

Figure 5.11 Map of Gjøa Area



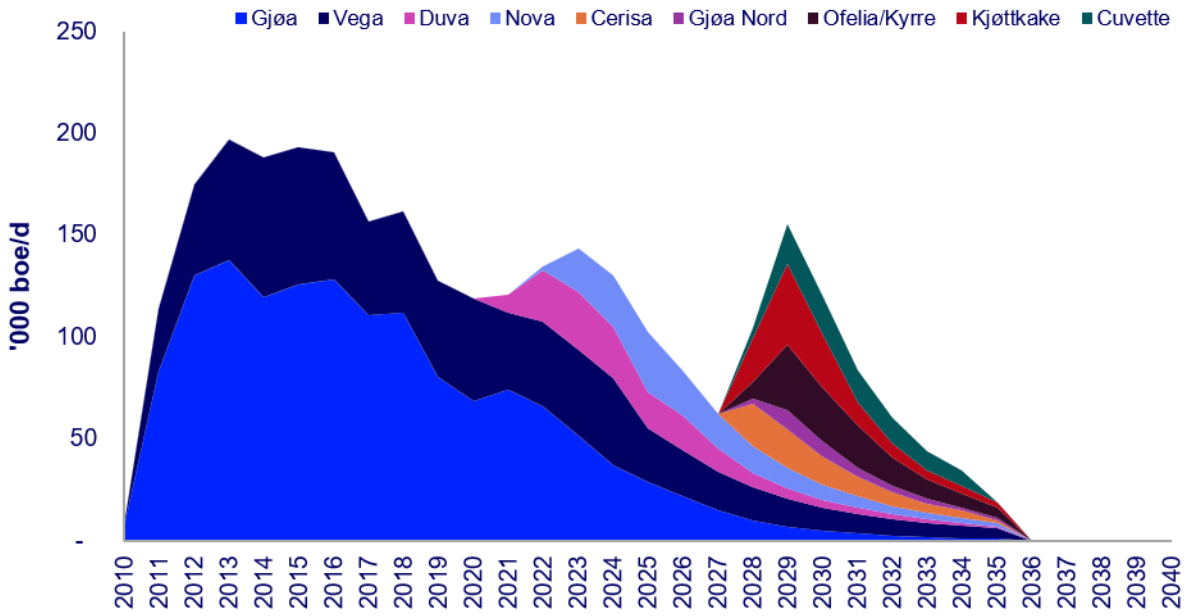
Source: Wood Mackenzie

Table 5.6 Gjøa Area summary

Field	Status	Operator	Start-up year	Concept	Total Reserves (mmboe)	Remaining Reserves (mmboe)
Gjøa	On production	Vår Energi	2010	Semi-sub	521	25
Vega	On production	Harbour Energy	2010	Subsea	305	43
Duva	On production	Vår Energi	2021	Subsea	58	20
Nova	On production	Harbour Energy	2022	Subsea	60	32
Cerisa	Approved for development	Vår Energi	2028	Subsea	29	29
Gjøa Nord	Approved for development	Vår Energi	2028	Subsea	12	12
Ofelia/Kyrre	Approved for development	Vår Energi	2028	Subsea	45	45
Kjøttkake	Justified for development	Aker BP	2028	Subsea	45	42
Cuvette	Justified for development	Harbour Energy	2028	Subsea	32	32

Source: Wood Mackenzie. Remaining reserves as of 1 January 2026. COP = cessation of production.

Figure 5.12 Gjøa Area production profile (2010-2040)



Source: Wood Mackenzie. Base case production profile as of April 2026. The operator is targeting life extension to around 2040. Peon is not included as a tie-back scenario as the confirmed concept was not included at the time of the study.

5.4.2 Yet-to-find prospective resources

The study includes estimates of yet-to-find resources based on Wood Mackenzie's Norwegian North Sea basin analysis (see Appendix A). The Norwegian North Sea has an estimated 2.9 billion barrels of oil equivalent (boe) of yet-to-find resources. Of this total, 150 million boe of future exploration success has been allocated as near-field discoveries that would utilise the Gjøa platform as a host for production, processing and export.

The yet-to-find analysis includes model field discovery sizes of 15 and 30 million barrels of oil equivalent based on the maturity of the area, recent exploration results and the volume of yet-to-find resources. The year of discovery and prospect size are shown in Table 5.7.

Table 5.7 Phasing of yet-to-find prospective discoveries

Model discovery size (mmboe)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
15	0	1	0	0	1	0	1	0	1	0	0	0	0	0	0
30	0	1	0	1	0	1	0	0	0	0	0	0	0	0	0
Total	**0**	**45**	**0**	**30**	**15**	**30**	**15**	**0**	**15**	**0**	**0**	**0**	**0**	**0**	**0**

Source: Wood Mackenzie

5.4.3 Emissions and emission costs

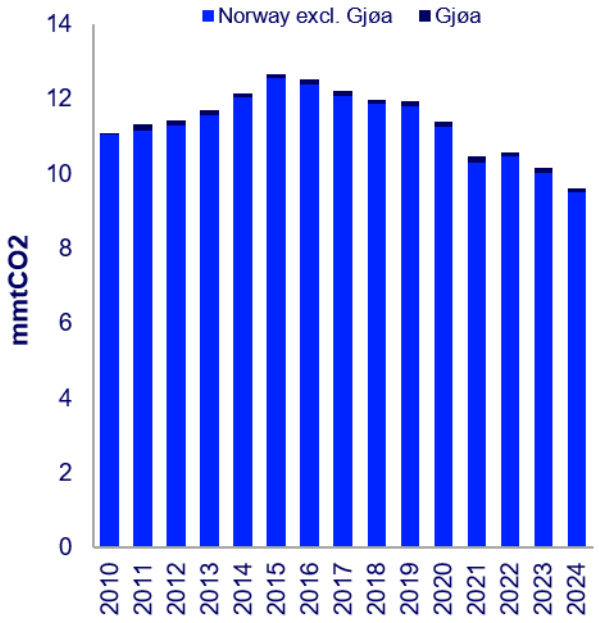
The Gjøa Area emitted around 100 $ktCO_2$ in 2024, equivalent to just 1% of total emissions across the NCS. A CO_2 intensity of 2 tCO_2/kboe was significantly lower than the 6.3 tCO_2/kboe average on the NCS (excluding methane) and the non-electrified Skarv Area (7.6 tCO_2/kboe). We estimate that emissions will rise incrementally until 2029 as development activity and new production is added and remain flat until production ceases (see Figure 5.13).

Power from shore supplies approximately 40 MW of power to the Gjøa platform, representing around 50% of the required

supply. The remaining electrical power is generated by a gas turbine that also drives gas export compression. Most of the CO_2 emissions come from the turbine exhaust system on the platform. Emissions are also generated from smaller and occasional sources such as safety flaring and gas venting during maintenance and other marine activity on the field (e.g. drilling rigs, service vessels).

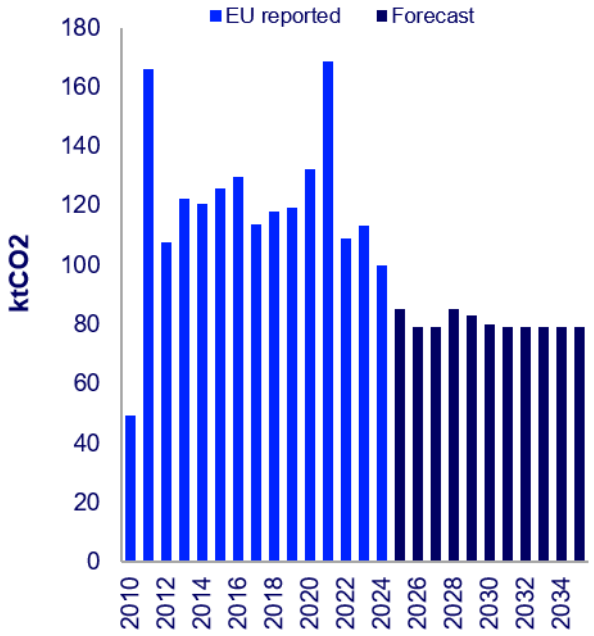
Figure 5.13 Absolute NCS and Gjøa Area CO_2 emissions

Norway upstream fields CO_2 emissions (2010-2024)



*Annual verified emissions from the Union Registry. 2025 data not available at time analysis commenced.

Gjøa Area CO_2 emissions: reported and forecast



*Reported emissions up to and including 2024. 2025 data not available at the time analysis commenced. Wood Mackenzie forecast on the low end of operator guidance.

Source: Wood Mackenzie

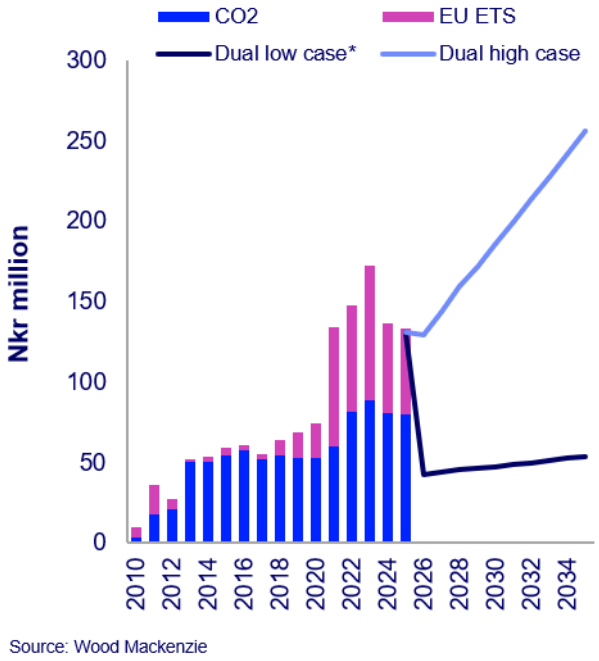
The combined Norway CO_2 and EU ETS emission costs doubled between 2020 and 2022. But declining emissions since 2021 have offset the rising EU ETS prices, Norway's dual carbon price plan (see Appendix 6.2) and a weaker Norwegian Krone against the Euro and US dollar.

Total carbon emission costs have marginally increased as a proportion of overall operating costs. However, the impact is small with total emission costs accounting for around 10% of overall operating costs (see Figure 5.14). This is equivalent to around NOK 3/boe or US$0.3/boe (nominal). This is significantly lower than the Skarv Area, illustrating that even partial electrification can reduce the impact of emissions and operating costs.

Like Skarv, the Gjøa field will also benefit from the start-up of new fields in the area. The Gjøa platform will process and export all the hydrocarbons produced so production and processing emissions will be distributed on a production throughput basis at the host. New satellite fields will take on a share of the overall CO_2 costs.

Figure 5.14 Gjøa Area CO_2 emission costs

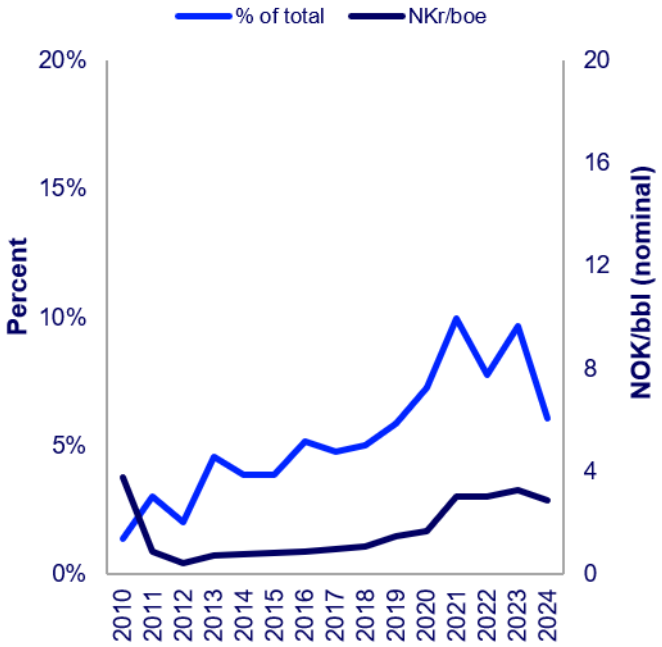
Gjøa Area CO_2 costs reported and scenario forecast



Source: Wood Mackenzie

NOD reported CO2 emission cost. *Dual low case excludes CO_2 tax, EU ETS only. **Wood Mackenzie calculated EU ETS costs. Nominal to 2025 and 2026 real terms from 2026 onwards. For Dual price case assumptions see Appendix A.

Gjøa Area CO_2 costs as share of total and unit opex



Reported CO2 and Wood Mackenzie estimate EU ETS costs as a percentage of total reported operating costs in nominal terms. Excludes G&A and transportation and tariff assumptions.

Source: Wood Mackenzie

5.4.4 Scenario analysis

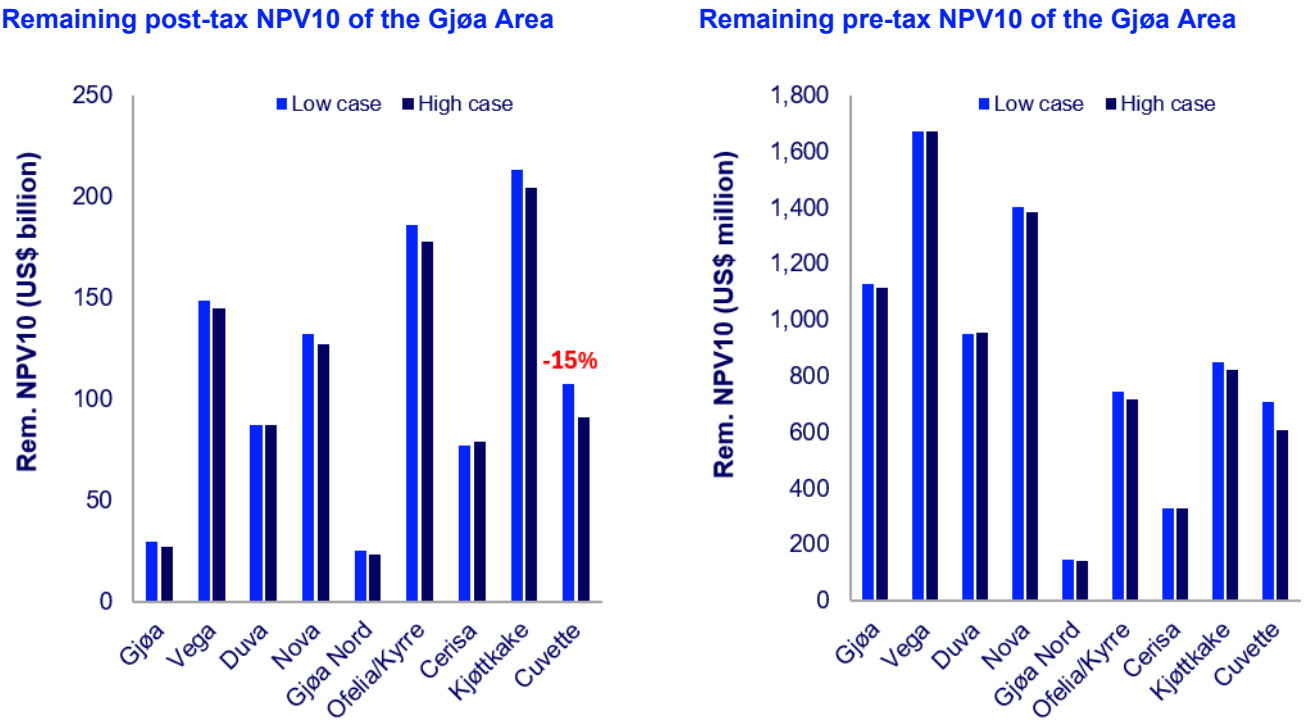
Low- and high-case carbon tax impact on the Gjøa Area

Economic analysis of the Gjøa Area applies the same methodology as Section 3 and Section 4 where the effects of the low- and high-case carbon tax scenarios are illustrated.

The results of the scenario modelling presented in Figure 5.15 show that a higher carbon tax reduces NPV10 in both pre- and post-tax cases. This is expected, since a higher CO_2 tax increases opex, lowering net cash flows. Since the CO_2 tax is tax-deductible, its net impact is partially offset by lower taxable income.

The impact on post-tax NPV10 is higher compared with the pre-tax impact. The average value lost increases from 2.3% (pre-tax) to 4.4% (post-tax). The CO_2 tax scenarios also impact remaining reserves and field life. Remaining reserves in the Gjøa Area are 15 mmboe or 5% lower in the high-case compared to the low-case carbon tax scenario with field life expected to cease 2.1 years earlier on average. This is higher than the non-electrified Skarv Area on a hub basis due to the Cuvette field's short life (see below). However, the average reserves lost per field at Skarv is 1.95 mmboe compared to 1.65 mmboe at Gjøa to highlight the greater impact at the non-electrified hub.

Figure 5.15 Impact of low- and high-case carbon tax scenarios on NPV10 value of the Gjøa Area



Source: Wood Mackenzie

Cuvette is the outlier in the Gjøa Area with a 15% and 14% reduction in pre- and post-tax NPV respectively between the low and high carbon tax scenarios. The project's IRR is reduced by two percentage points but remains well above 70% under both the low and high case scenarios. There is no threat to project economics or hurdle rate thresholds as a result. But production ceases three years earlier under the high case compared to the low case with remaining reserves cut by 5 mmboe or 14%. Shorter field life under the high carbon tax scenario is the driver with carbon costs in line with the proportion of reserves across the hub.

Yet-to-find analysis

The yet-to-find analysis is considered at the hub level, not individual model prospects. The Gjøa Area study includes seven prospects with a combined prospective resource of 150 million barrels of oil equivalent, with a liquid and gas split of 70:30.

The results of the scenario modelling show that higher carbon taxes have a greater effect on Norway's yet-to-find resources than on its commercial reserves. While several prospects don't meet the investment threshold of a 15% IRR, all could be considered economic with IRRs greater than 10%. This is a marked difference compared to the Skarv Area where the high carbon cost scenario resulted in negative NPV10 across all prospects.

Under the low case, the seven modelled prospects have a combined NPV10 of US$173 million (NOK 1.7 billion). This falls to US$165 million (NOK 1.6 billion) excluding one prospect with an IRR of 14.9% – just falling short of the 15% IRR hurdle rate (Figure 5.16). This is equivalent to 15 mmboe of the total 150 mmboe of prospective resource that would not be developed.

Under the high case, all the model prospects have an IRR of over 10% (positive NPV10), but three of the four 15 mmboe prospects fail to meet the 15% hurdle rate[22]. This reduces the combined post-tax NPV10 of US$150 million (NOK 1.4 billion) to US$130 million (NOK 1.2 billion) or 14%. The post-tax NPV10 of prospects that make a 15% IRR is reduced by 22% between the low and high carbon tax scenarios.

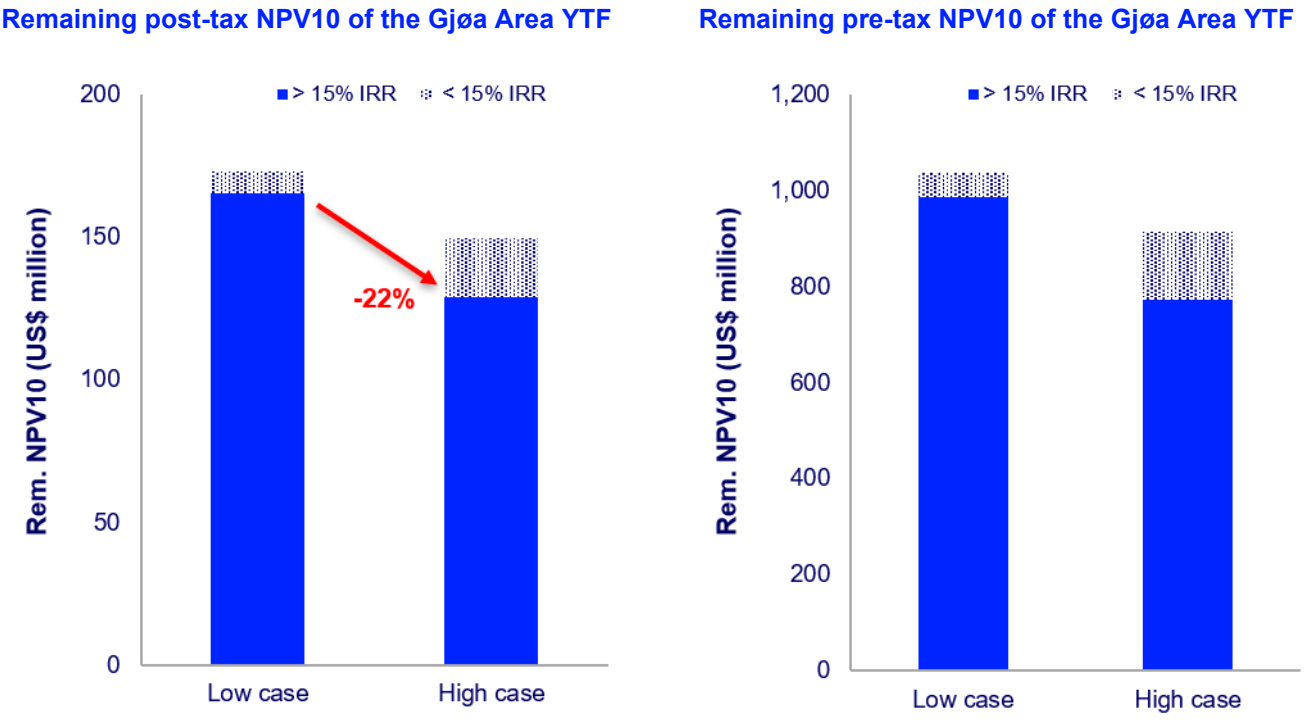
The three 15 mmboe prospects that don't meet the 15% hurdle rate are equivalent to 30% of the 150 mmboe resource modelled, illustrating that in a high case scenario, the development for future tie-ins would become more challenging.

[22] *Out of the four 15 mmboe economically viable (NPV10 >0) YTF prospects modelled, one does not meet the IRR threshold of 15% in the low-case scenario. Of the remaining three, a further two don't achieve an IRR of 15% under the high-case scenario.*

The remaining 15 mmboe prospect falls out of the investable set if carbon costs across the remaining four prospects are increased by 50%. All three 30 mmboe prospects remain robust under this scenario, highlighting the benefit of electrification on future developments for medium-sized discoveries. Production under both scenarios could extend the life of the Gjøa hub to 2050. Like the Skarv Area analysis, given the range of uncertainty, cluster developments could likely make some of the smaller prospects economic.

A trend in the Gjøa Area analysis is the declining IRRs that correspond with the timing of first discovery and production start-up. This relates to increasing CO_2 costs over time as well as overall throughput decline from the Gjøa Area, illustrating the negative effect this could have on future exploration and discovered resources in the area.

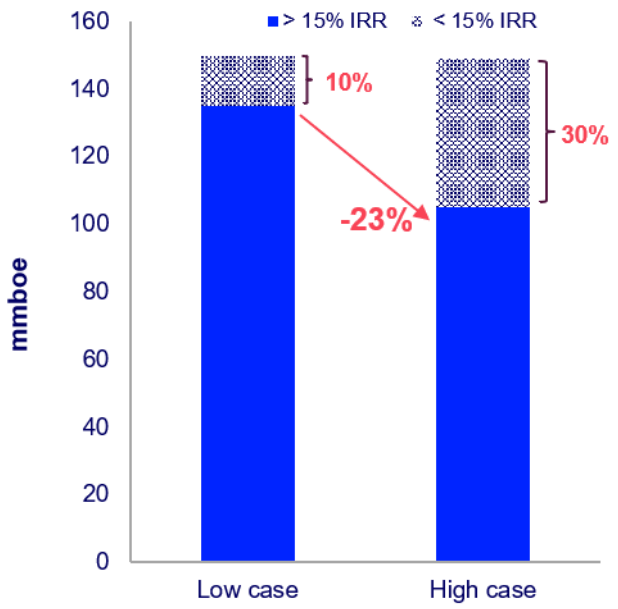
Figure 5.16 Impact of low- and high-case carbon tax scenarios on NPV10 value of the Gjøa Area YTF



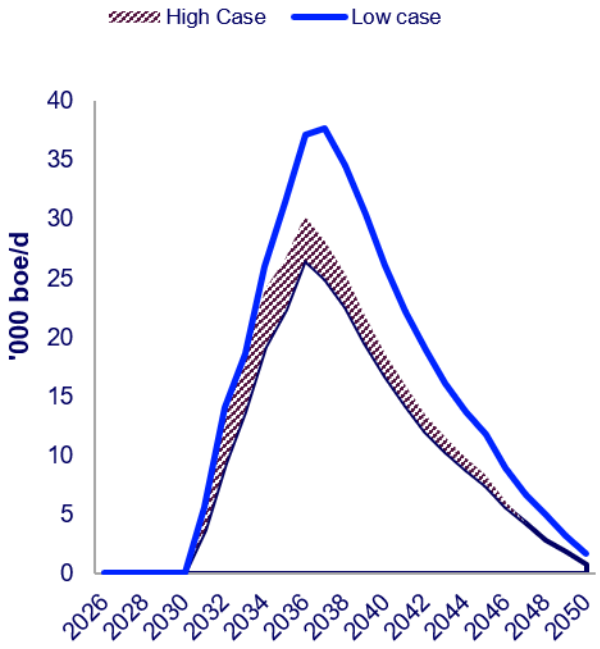
Source: Wood Mackenzie. Hashed areas represent NPV10 that is below a 15% IRR investable hurdle rate. Pre-tax NPV includes deduction of CO_2 taxes which are treated as operating costs.

Figure 5.17 Impact of low- and high-case carbon tax scenarios on Gjøa Area YTF resources and production

Gjøa Area YTF resources by investment threshold



Gjøa Area YTF production (2026-2050)



Source: Wood Mackenzie. Hashed areas represent prospects that generate an IRR below a 15% IRR investment hurdle rate. The Low case and High case production profiles only include prospects that meet the 15% IRR investment hurdle rate.

6 Appendices

6.1 Appendix A: Detailed methodology for scenario analysis

This appendix provides a comprehensive breakdown of the framework, modelling logic and approach used in this study. To deliver a granular, bottom-up assessment of the NCS, Wood Mackenzie conducted an intensive asset remodelling exercise involving the modification and manipulation of 164 commercial and economically viable field models and 179 yet-to-find exploration discoveries to evaluate the impact of two highly divergent regulatory pathways on the future of Norway's upstream oil and gas industry.

6.1.1 Scenario analysis for the commercial and economically viable fields (Static Effects)

The evaluation of static effects examines commercial, fiscal, and volumetric sensitivities of commercial and economically viable fields to variations in carbon pricing. This phase uses individual asset cash flow models built specifically for 164 unique fields distributed across the entire NCS. The scope covers all discoveries classified by Wood Mackenzie as "on production" (onstream), "approved for development" (under development), and "justified for development" (probable development), and "economically viable" assets.

The majority of Norwegian hydrocarbon production relies on centralised hubs, which are large field facilities that serve as host platforms, processing well streams from multiple surrounding satellite fields. Environmental tax exposures are calculated and distributed as follows:

- Under Norwegian regulatory protocols, the designated host field operator retains the primary legal responsibility for measuring, logging, and paying all centralised CO_2 taxes, NOx taxes and surrendering/paying the EU ETS carbon allowances/costs for the entire host facility.

- The environmental taxes and other operating costs are contractually reallocated to the satellite tie-in fields based on a negotiated tie-in agreement. For the purposes of this study, the cost allocation is calculated in direct proportion to each asset's annual average production passing through that specific hub facility.

- The resulting reallocated taxes are incorporated into the asset cash flow models as an additional operating cost. It must be noted that the tie-in fields also pay a tariff to the host hub to help cover the hub's operating costs. However, that is not varied when evaluating the sensitivity to high and low CO_2 taxes.

The Norwegian Ministry of Energy has provided the low-case and high-case pathways, as shown in Figure 1.1.

- Low Case: Assesses a scenario where the domestic CO_2 tax is fully removed, leaving only the EU ETS price deck active, rising from NOK 872/t by 2030 to NOK 945/t by 2035, and reaching NOK 1,204/t by 2050 in real 2026 terms.

- High Case: This scenario tracks an aggressive dual-tax framework where an escalating Norwegian CO_2 tax is stacked on top of the EU ETS, with total carbon costs increasing linearly to NOK 2,971/t by 2030, NOK 3,500/t by 2035, and NOK 6,138/t by 2050 in real 2026 terms.

For each scenario, the total carbon tax is calculated at the hub level and then distributed among the tie-in fields based on the principles described above. These costs are incorporated into the field's cash flow model, and the model is recalculated for the operating cash flow (OCF) on a yearly basis.

- When a field is subject to the high-case trajectory, escalating CO_2+ETS costs compress late-life operating margins, bringing the asset's economic end-of-life threshold forward in time, where the OCF becomes negative. This results in lower reserves being produced until the cessation of production (CoP) date, compared to the low case scenario. The updated cash flows recalculate all commercial variables such as post-tax and pre-tax NPV, state share PV and recoverable reserves. These metrics are then aggregated up to the country level.

6.1.2 Scenario analysis for yet-to-find resources (Dynamic Effects)

To project the long-term dynamic effects on exploration and the economics of new discoveries, the study incorporates the impact of CO_2 pricing on the undiscovered prospective resource potential across four basins: the Northern North Sea, Vøring Basin, Central Graben, and the West Barents Sea.

Modelling of YTF volumes by basin

Wood Mackenzie uses a projected creaming curve to derive our assumption of prospective resources potential in each play. The curve is generated using best fit of a hyperbolic trend to historic data on cumulative resource by cumulative exploration wells. The curve's trajectory is also an assumption of resources that will be discovered per exploration well. The overall play prospective resources assumption is constrained by our forecast of exploration well numbers to 2050.

Our prospective resources assumption is intended to be a broadly realistic input to our future economics evaluation. It is not a substitute for a geologically constrained resource assessment. We also forecast future exploration well success rates and average discovery sizes. These forecasts are based on projections of trends and, by implication, are consistent with the projected creaming curve.

Where little or no prior exploration has taken place, we cannot use a projected creaming curve to derive our assumption of prospective resource potential. Prospective resource volumes are therefore determined using the following methodology:

- Drilling – annual exploration drilling is forecast based on forward drilling plans of operators, outstanding well commitments, expected availability of rigs and likely future licensing activity
- Success rates – a future exploration success rate is estimated based on the average success rate achieved for wells drilled in analogous basins
- Volumes – the average volume discovered per exploration well drilled in analogous basins in similar locations is multiplied by our drilling estimate to give a prospective resources estimate

Ultimately, the final outcome of the YTF modelling process is a comprehensive forecast of prospective discoveries with individual asset sizes varying between 10 and 100 mmboe. For this study, the model incorporates 179 distinct prospects that are projected to be discovered and developed between 2027 and 2050 and expected to be developed via tie-backs to existing hubs. This assumes that there are no new areas opened and which are expected to be developed via new infrastructure (FPSOs or platforms). Combining and stacking the individual production schedules from each of these 179 prospects creates the definitive yet-to-find production outlook (as shown in Figure 2.1) for Norway. This outlook is also compared with published estimates (such as from the NOD) for benchmarking and calibration of our model. However, Wood Mackenzie's production outlook represents an independent view of Norway's future oil and gas production and is not intended to match any third-party forecasts, including those published by the NOD.

Scenario analysis for the YTF volumes

Through targeted operator consultations and extensive asset screening, Wood Mackenzie identified specific production hubs in each basin capable of handling subsea tie-backs for these prospective discoveries. New fields are assumed to route volumes through these specific host fields, as shown in Table 6.1.

Where YTF fields produce beyond the economic life of the hub's parent field, we assume that the host facilities remain operational despite the cessation of production from the parent field itself. In this case, continued operation is supported by tariff revenues generated from the YTF fields, thereby extending the economic viability of the existing infrastructure. Importantly, this extends the life of the host facility only without assuming any change to the production profile of the parent field or of the other fields tied into the hub. Each producing field is held to its own standalone economic cessation, and no additional volumes or extended production are credited to those fields as a result of YTF developments. In practice, a parent field or a tied-in field may itself be able to produce for longer, and the presence of YTF volumes could help keep a hub open for the benefit of those fields. Capturing this would require field-specific assumptions not only on remaining reserves and reservoir dynamics, but also on future operating and capital costs and any brownfield redevelopment required to keep the infrastructure in service. Forecasting these factors so far into the future makes such assumptions unreliable at this level of analysis. Holding existing-field production fixed is therefore a deliberately conservative simplification: accounting for such interdependencies would tend to increase the reserves and value lost when YTF prospects are not developed under a high CO2 tax.

Table 6.1 Yet-to-find (YTF) prospect distribution by hubs

Basin Name	Hub Name	Prospect size (mmboe)							Total YTF volumes (mmboe)
		10	15	20	30	50	75	100	
West Barents Sea	Johan Castberg	7			5	4	3		645
	Goliat Area	2			3	2			210
Vøring	Aasta Hansteen			8		4		1	460
	Åsgard	11		10		5		2	760
	Njord	3		2		1			120
	Skarv Area	4		4					120
Norwegian North Sea	Sleipner Vest Unit		4		2	1			170
	Grane		6		2				150
	Johan Sverdrup				5	3			300
	Alvheim		5		1				105
	Yggdrasil		5		7	5	3		760
	Troll		5		7	5	3		760
	Gjøa Area		4		3				150
	Snorre				5	3			300
	Gullfaks Area				5	3			300
Central Graben	Ekofisk Area II	1		1		1			80
	Valhall	1		1		1			80

To assess the implications of high and low case carbon pricing, a complete economic cash flow model was created for every prospect, yielding a total of 179 individual cash flow models incorporating the production curves, costs and lead times specific to each prospect and basin.

Mirroring the methodology for the static effects, projected emission costs from the selected hubs are distributed to the new tie-backs to evaluate their environmental tax liabilities under each scenario. Finally, each cash flow is recalculated to determine the economic and volumetric metrics in the high and low case scenarios.

As discussed in our results presented in Section 4, the decrease in the investability and the subsequent removal of YTF prospects under the high-case CO_2 tax scenario significantly increases the CO_2 taxes to be paid by the remaining prospects. The increase depends on the hub emissions and number of prospects tied into the hub.

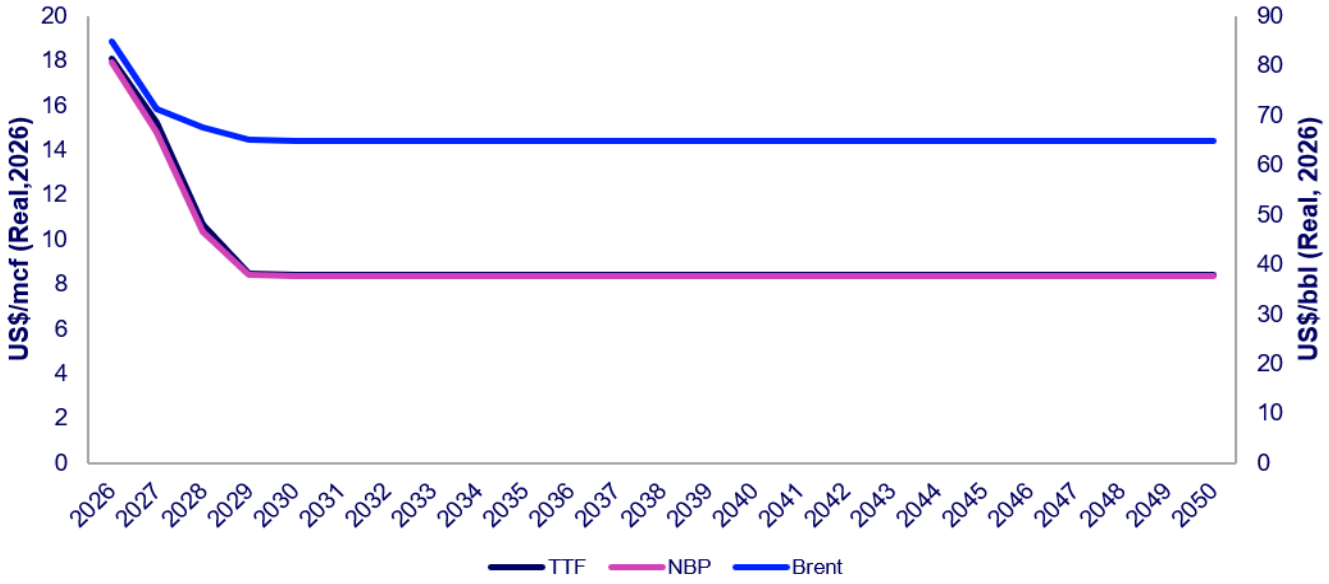
The study considered selected non-electrified hubs and tested the impact of removing prospects which are not investable due to the high CO_2 tax and redistributing the hubs' CO_2 tax to a smaller number of prospects. With fewer developments available to share emissions costs, the burden concentrates on the remaining investable fields, raising their CO2 costs by an average of 71%. This 71% figure reflects the selected non-electrified hubs only. Electrified hubs showed little to no uplift under the same treatment, reflecting their substantially lower operational emissions. Weighting the uplift across non-electrified, partially electrified and fully electrified assets gives an average increase of around 50%, which is the figure applied in this analysis as an average upward mark-up to the emissions costs allocated to individual discoveries. This allows us to account for the consequential impacts of high CO_2 taxes on YTF volumes.

6.1.3 Wood Mackenzie's price assumptions used in the asset valuations

The charts below capture the Brent, TTF and NBP pricing assumptions used for this study. It must be noted that the

price assumptions for each asset are unique (at a premium or discount to benchmark prices) and arrived at in discussions with the operator. Oil prices are primarily indexed to Brent, and gas prices are indexed to either NBP or TTF.

Figure 6.1 Price assumptions used in this study for Brent, TTF and NBP



Source: Wood Mackenzie

6.1.4 Emissions calculation methodology

The Wood Mackenzie emissions modelling includes operations required to produce oil or gas from the wellhead to the point at which it is available for sale (for example, on the water for tankered oil, or at a refinery gate, or head of a major gas transmission line). Emissions from the following upstream activities are considered: drilling, production and processing, along with associated CO2 venting, flaring and methane losses. Asset-level emissions intensities are derived using a methodology that integrates Wood Mackenzie's extensive upstream asset data with empirical upstream emissions intensity data from the public domain and inputs to, and outputs from, the OPGEE (Oil Production Greenhouse Gas Emissions Estimator) model developed by Stanford University.

Drilling emissions depend mainly on well depth, length and fuel source, with deeper and more complex wells requiring longer drilling times and greater energy use. Production emissions vary according to the recovery method employed, ranging from lower-intensity primary recovery to more energy-intensive secondary and tertiary techniques, while the use of natural gas, diesel or electricity also influences emissions levels. Processing emissions are determined by the composition of the hydrocarbons produced, with gas containing high levels of CO2 or H_2S requiring significantly more energy to treat. Flaring emissions are estimated using satellite data to quantify gas burned during operations and allocate associated emissions to individual fields or production basins. Venting emissions arise when excess CO2 is removed from gas streams and released to the atmosphere, particularly in high-CO2 gas fields and LNG supply chains. Methane losses account for intentional releases, leaks and incomplete flare combustion, with emissions converted to CO2-equivalent using standard global warming potential factors. Together, these sources provide a comprehensive measure of operational emissions intensity across the lifecycle of an oil and gas field.

For conventional oil and gas assets, there is a direct relationship between emissions intensity and maturity. Emissions intensity spikes during production start-up and then increases again as the field matures. Not only do mature fields require more intensive recovery methods to extract the hydrocarbons, production and processing equipment continue to operate at full capacity even as the volumes of hydrocarbons produced decline. To reflect this relationship, we have applied multipliers to the production and processing emissions intensities based on the level of production in any given year of the forecast period relative to peak/plateau production or facility capacity. These multipliers are based on empirical data for North Sea fields released by the Norwegian and UK governments.

Absolute emissions for each asset are then calculated by multiplying the asset's total emissions intensity in each year, as defined by the categories above, by Wood Mackenzie's forecast for production in that year. Our detailed methodology is available here.

6.2 Appendix B: References

1. Wood Mackenzie Upstream research and data (Data cut-off for this study is 1 April 2026)
2. Norwegian Offshore Directorate – https://www.sodir.no/en/
3. Petro.no – https://petro.no/artikler/aker-bp-vil-elektrifisere-skarv-med-kraft-fra-land
4. Norwegian Government – https://www.regjeringen.no/en/documents/meld.-st.-13-20202021/id2827405/?ch=1

6.3 Appendix C: Wood Mackenzie's upstream research methodology

6.3.1 Classification of discoveries

Wood Mackenzie subdivides discovered resources by commerciality into commercial and sub-commercial. Assets are further subdivided depending on their development status.

Commercial

Commercial assets are defined as those on production, under development or likely to be developed. Detailed coverage of commercial fields that are depleted and/or abandoned will usually stop after abandonment, but the details of these fields are retained in our databases. Wood Mackenzie sub-classifies commercial assets as:

- On production (onstream): the field is currently producing. For example, Troll, Johan Sverdrup, Balder & Ringhorne, etc.
- Approved for development (under development): the field is currently in the main construction phase, with the final investment decision having been taken. For example, Yggdrasil.
- Justified for development (probable development): the field development plan is mature, and the development is expected to proceed. Typical indicators are positive economics, momentum and alignment between stakeholders to start development in the short to medium term and no major contingencies or issues that could materially delay or suspend development activity. For example, Ringvei Vest, Atlantis, Adriana/Sabina, etc.

Sub-commercial

Sub-commercial assets contain discovered volumes of petroleum potentially recoverable by a development project but not currently considered to be commercial. This may be due to a number of reasons. For example, a lack of development plans, low resource volumes, technical constraints, low product quality, or the lack of accessible markets (such as stranded gas deposits) or viable price regimes.

Wood Mackenzie further sub-classifies sub-commercial assets as:

- Economically viable (good technical): these are fields that could be economic under our current costs and price projections, but significant uncertainty remains over the nature and timing of their development. For example, Wisting, Linnorm, Peon, etc.
- Not viable (contingent): these are fields we do not expect to be developed under current costs and price projections. To become economically viable, these fields may require a breakthrough in technology, a step-change in prices, new fiscal terms or access to as yet unplanned infrastructure or markets. For example, Ellida, Stetind, Victoria, etc.

6.3.2 Key steps – asset modelling

Commercial assets

Wood Mackenzie's reserve estimates cover all fields we classify as commercial: fields on production or under development, as well as fields which Wood Mackenzie classifies as justified for development. Our oil and gas reserves and production estimates are based on our 'best estimate' view of likely future production. We do not conduct independent reservoir studies or engineering assessments. However, we do use data related to such studies to form our view of individual well performance. We also use external data, such as Norway's production outlooks released by the Norwegian Offshore Directorate, to benchmark and calibrate our field models.

In conventional plays, we make an independent analysis of production forecasts provided by operators and/or partners, integrated with our own view of other commercial factors such as demand, infrastructure availability and costs. We validate this assessment by comparing this to data from analogous fields in the same basin or region.

For fields and plays where upside is known to exist, for example where isolated sections of a reservoir have yet to be drilled, this will be noted in the report. Forecast costs and resultant production profiles associated with these possible resources are not included in our base-case economic analysis.

Capital and operating costs

Wood Mackenzie models capital and operating expenditure at the field or field grouping level.

Exploration and appraisal (E&A) costs: In many cases in conventional fields, cash flows do not include E&A costs, and hence the economics presented represent project economics, not full life-cycle economics. In these cases, the exploration history and costs incurred are discussed in the field report, and the E&A costs may be included in the corporate files within our model for each company.

In some regions, E&A costs are included in the field cash flows, usually in PSC-type regimes, since they have an impact on the tax calculation. In our full-cycle economic models for unconventional projects, access costs, pilot wells, and seismic fees are also included.

Capital costs: these include, where relevant, costs for production facilities (including water management), processing equipment, subsea facilities, pad construction, development drilling, completion and well stimulation, pipelines, offshore loading facilities, terminals, abandonment costs and any other costs that are typically capitalised.

Operating costs: these include, where appropriate, fixed and variable costs for field operations, transportation (non-tariff), equipment leasing, insurance and asset-level G&A costs. Additionally, they include any tariffs paid for transportation and/or production processing. For Norway, this also includes the CO_2 tax, NOx tax and EU ETS tax.

Sub-commercial fields

Wood Mackenzie calculates indicative values for economically viable sub-commercial fields based on simple inputs from analogue discoveries. The key drivers of value are the chosen development solution and the resources believed to be recoverable. Using these, our model interpolates between sets of model asset production profiles for liquids and gas streams and capital investment profiles for that specific development solution type at different resource sizes.

Capital costs are based on the development solution, recoverable volumes, with controls including: water and reservoir depths, well costs and recoveries, distance to any infrastructure likely to be used, and local cost environments. Operating costs are also based on development solution, adjusted for local costs and any appropriate tariffs. Appropriate tax and product prices are also applied.

An indicative valuation of a successful development is then derived from a discounted cash flow produced in Wood Mackenzie's Global Economic Model (GEM) tool, under our standard economic assumptions. This does not include any assessment of risk or the likelihood of any development proceeding, or any additional interim costs likely to be incurred before project sanction is achieved, such as further appraisal costs or FEED studies.

6.4 Appendix D: Calculation of Norway's IOGR potential

Wood Mackenzie conducted an independent study on Norway's IOR potential. The full report is available to our subscribers on the Wood Mackenzie portal. Selected slides relevant to this study are included here in this appendix.





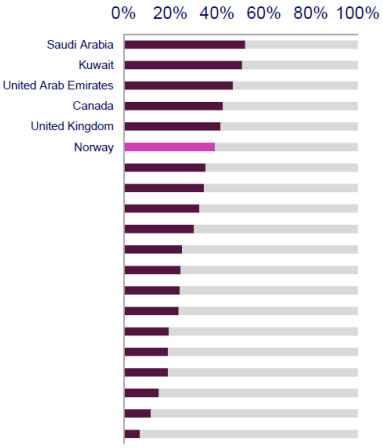
Recovery factor benchmarking

5

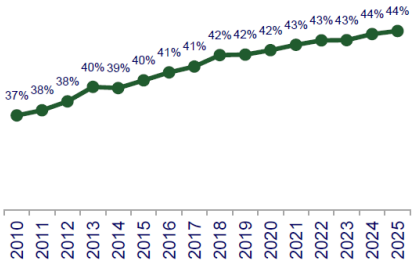
Norway's recovery factors rank among the highest globally for top oil producing nations

Oil and gas recovery from Norway's legacy fields** have increased over the last 15 years thanks to continued investment, additional development phases and deployment of advanced recovery technology

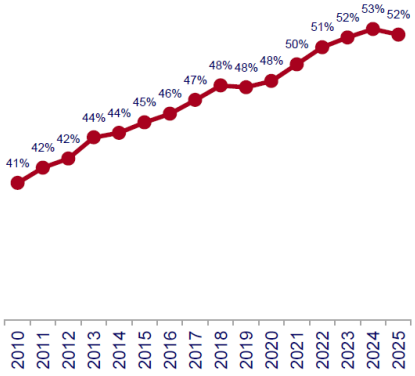
Average conventional oil recovery factors by key producing country*



Norway average oil recovery factor change over time for legacy fields**



Norway average gas recovery factor change over time for legacy fields**



*Countries that have produced the most oil reserves globally

**Fields that have reported commercial reserves annually from 2010

Source: Wood Mackenzie, Norwegian Offshore Directorate

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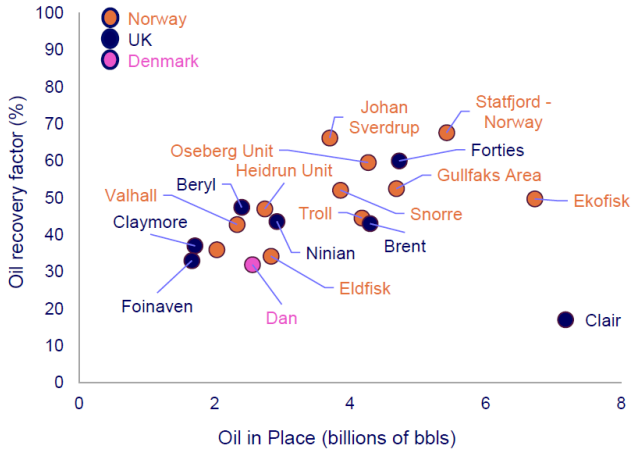
Recovery factor benchmarking

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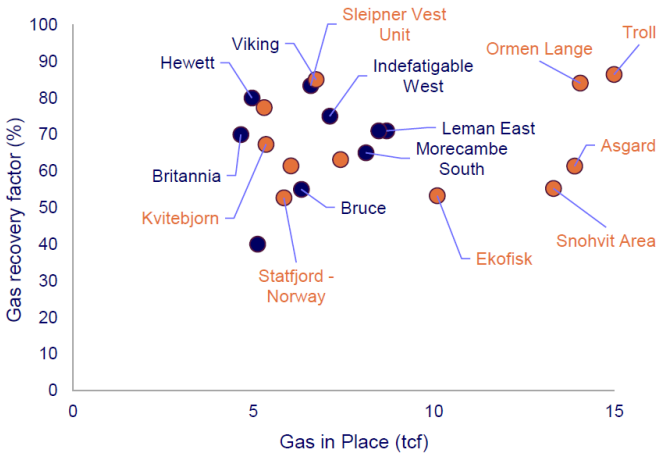
Norway squeezes more out of its largest oil fields than the UK and Denmark

Major gas fields in the UK and Norway achieve high recovery rates, but Norway benefits from larger volumes

North Sea* largest oil fields by recovery factor



North Sea* largest gas fields by recovery factor



*North Sea plus Norwegian Sea, West of Shetlands, Irish Sea and Norwegian Barents Sea. Largest fields defined by in place volumes.

Source: Wood Mackenzie

8

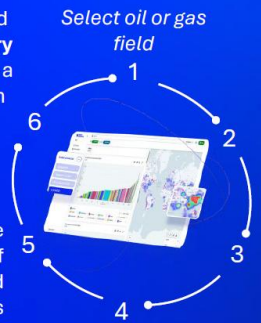
2. How much more can Norway recover?

Methodology

Using **Wood Mackenzie Synoptic AI** to assess recovery factor potential in Norway

Calculate un-risked "**improved recovery upside**" volume on a field level based on top analogue recovery factor distribution

Calculate analogue field distribution of **P50, P75, P90** oil and gas recovery factors

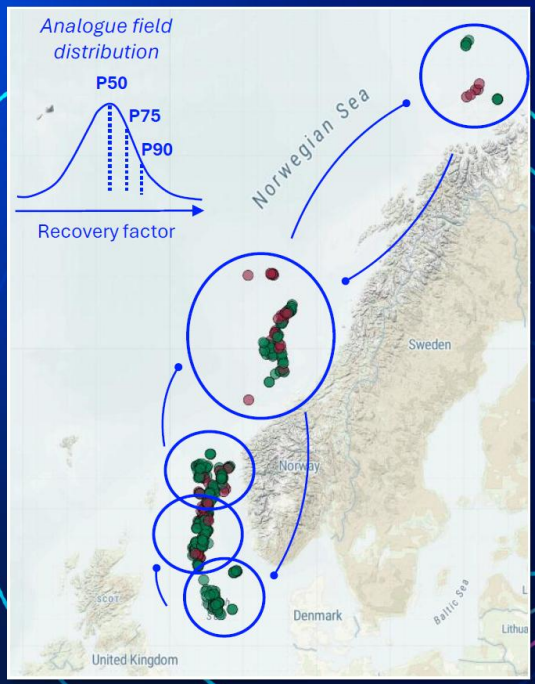


Return **top analogue fields** using unsupervised **machine learning** across Wood Mackenzie's subsurface property data

*Use **Wood Mackenzie Synoptic AI (Analogue Finder)** to assess field against **>350** other Norwegian fields in Lens Upstream*

***Analyse** and **apply weightings** to entire subsurface dataset for each field including **rock, hydrocarbon** and **location-based** parameters*

Wood Mackenzie Lens

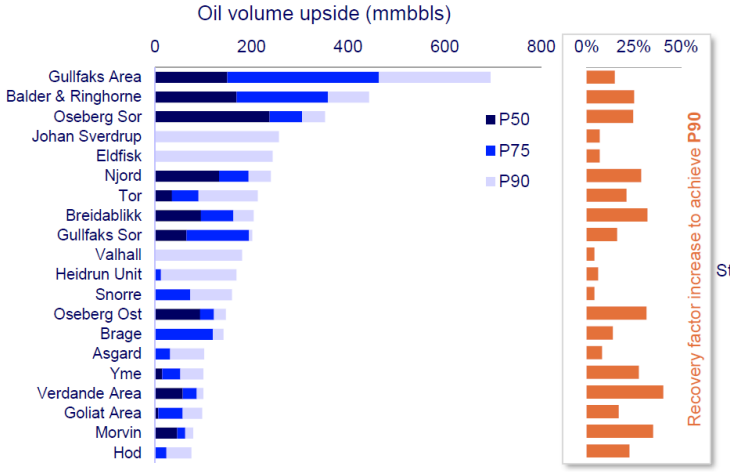


How much more can Norway recover? 12

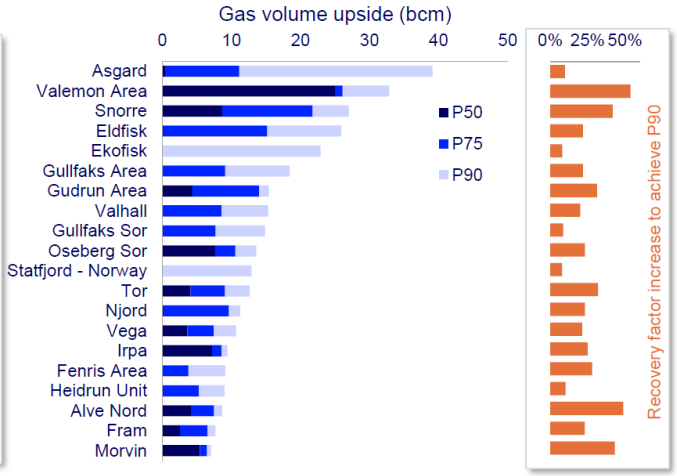
Using **Wood Mackenzie Synoptic AI** to identify fields with the largest upside potential

Gullfaks field identified as having significant oil and gas upside potential based on analogue field benchmarking, a 15% increase in recovery factor would unlock over 600 mmbbls

Recovery upside volume* for top 20 oil fields



Recovery upside volume* for top 20 gas fields



*Un-risked field upside based on analogue Norwegian recovery factor distributions for P50, P75 and P90 (see slide 19).

P50 : median recovery, P75: top quartile "top performers", P90: top 10% "best in class"

Source: Wood Mackenzie

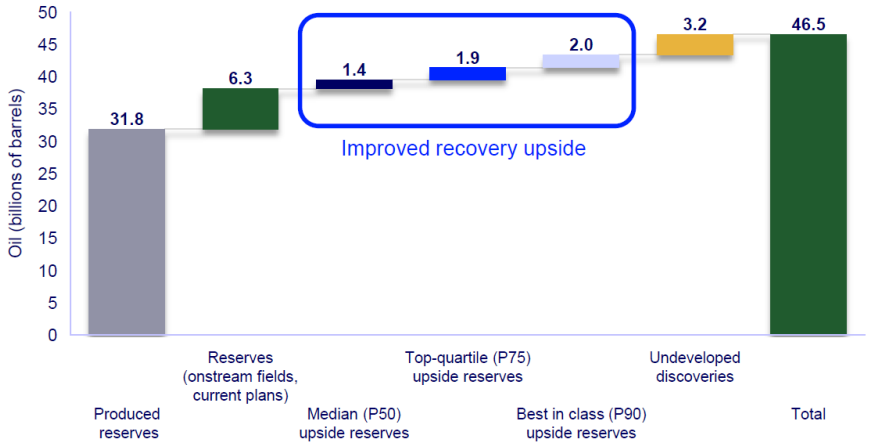
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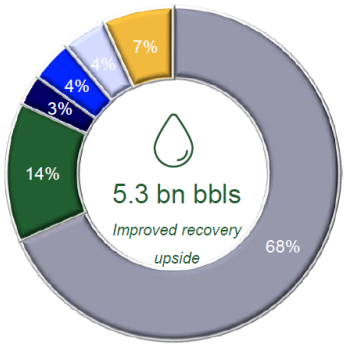
How much more can Norway recover? 13

Oil: Increased recovery from existing fields could unlock an extra 5 bn bbls

Boosting reserves at producing fields potentially offers a larger resource opportunity than developing existing discoveries

Oil reserves and resources by category





Reserves excludes fields that have been decommissioned

Source: Wood Mackenzie

13

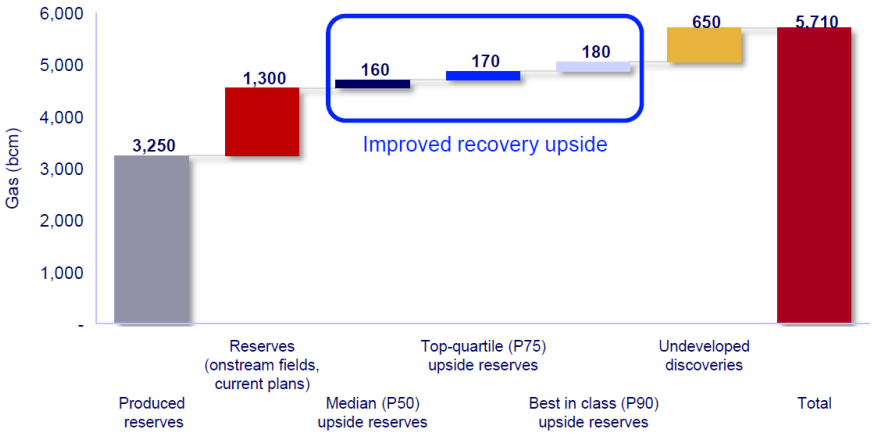
How much more can Norway recover?

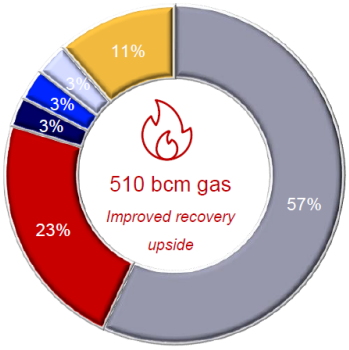
14

Gas: Norway could unlock over 500 bcm of gas through improved recovery at producing fields

Improved recovery could unlock gas volumes equivalent to the last 16 years of exploration discoveries

Gas reserves and resources by category





Reserves excludes fields that have been decommissioned

Source: Wood Mackenzie

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6.5 Appendix E: Glossary of terms

Term	Definition
Base Case	Wood Mackenzie's reference scenario for Norway's oil and gas production, reflecting current policy including the EU ETS and the Norwegian CO2 tax.
boe	Barrels of oil equivalent – a unit aggregating oil and gas volumes on an energy-equivalent basis (mmboe = million boe).
Capex	Capital expenditure – investment spending on developing and sustaining oil and gas assets.
CO2 tax	Norwegian tax levied per tonne of CO2 emitted from offshore petroleum activities, applied alongside the EU ETS.
COP	Cessation of production – the point at which a field permanently stops producing.
E&A	Exploration and appraisal.
ETS / EU ETS	Emissions Trading System – the European Union's cap-and-trade scheme for greenhouse-gas emissions, in which Norwegian offshore installations participate.
FEED	Front-end engineering and design – detailed engineering undertaken ahead of a final investment decision.
FID	Final investment decision – the formal commitment to proceed with developing a field.
FPSO	Floating production, storage and offloading vessel.
G&A	General and administrative costs.
Government take	The Norwegian state's total share of petroleum revenues, collected through taxes, the SDFI and other fiscal instruments.
IOGR	Improved oil and gas recovery – additional volumes recovered from existing fields beyond the base plan.
IOR	Improved oil recovery – techniques to raise the recovery factor of producing fields.
IRR	Internal rate of return.
LNG	Liquefied natural gas.
MtCO2e	Million tonnes of carbon dioxide equivalent.
MW	Megawatt.
NCS	Norwegian Continental Shelf.
NOD	Norwegian Offshore Directorate – the regulator for petroleum resources on the NCS.
NOK	Norwegian krone.
NOx	Nitrogen oxides.
NPV	Net present value.
NPV10	Net present value discounted at 10% per annum; NPV10/boe expresses this per barrel of oil equivalent.
OCF	Operating cash flow.
Opex	Operating expenditure – the ongoing cost of running producing assets.
PDO	Plan for Development and Operation – the development plan submitted to authorities for approval.
PRMS	Petroleum Resources Management System – the industry standard for classifying reserves and resources.
Scope 1 & 2 emissions	Direct emissions from operations (Scope 1) and indirect emissions from purchased energy such as electricity (Scope 2).
SDFI	State's Direct Financial Interest – the Norwegian state's direct ownership stakes in petroleum assets (also referred to as the State DFI).
TWh	Terawatt hour.
YTF	Yet-to-find resources – volumes not yet discovered but expected to be found through future exploration.

6.6 Appendix F: Summary results using 5% discount rate

Table 6.2 Summary results of the impact of low- and high-case CO_2 taxes on commercial and economically viable fields

Metric Name	Low-case value	High-case value	Change (%)
Pre-tax NPV5 (US$ billion)	544.1	542.6	-1.5 (-0.3%)
Investor Post-tax NPV5 (US$ billion)	76.7	71.9	-4.8 (-6.2%)
Government take (from profit-based taxes, CO2 tax and SDFI stake) (US$ billion)	467.4	470.6	3.3 (0.7%)

Source: Wood Mackenzie. Note: Investor Post-tax NPV5 excludes State DFI stake

Table 6.3 Summary results of the impact of low- and high-case CO_2 taxes on yet-to-find resources

Metric Name	Low-case value	High-case value	Change (%)
Pre-tax NPV5 (US$ billion)	75.1-77.5	63.9-70.4	-7.1 to -11.3 (-9% to -15%)
Investor Post-tax NPV5 (US$ billion)	12.6-13.0	9.7-10.9	-2.1 to -2.9 (-16% to -23%)
Government take (from profit-based taxes, CO2 tax and SDFI stake) (US$ billion)	62.5-64.4	54.2-59.5	-5.0 to -8.3 (-8% to -13%)

Source: Wood Mackenzie. Note: Investor Post-tax NPV5 excludes State DFI stake

Table 6.4 Summary results of the indicative impact of low- and high-case CO_2 taxes on IOGR resources

Metric Name	Low-case value	High-case value	Change (%)
Pre-tax NPV5 (US$ billion)	55.2-55.4	47.3-50.6	-4.8 to -7.9 (-9% to -14%)
Investor Post-tax NPV5 (US$ billion)	9.3-9.4	7.8-8.8	-0.5 to -1.5 (-6% to -16%)
Government take (from profit-based taxes, CO2 tax and SDFI stake) (US$ billion)	45.9-46.0	38.5-42.8	-3.3 to -7.4 (-7% to -16%)

Source: Wood Mackenzie. Note: Investor Post-tax NPV5 excludes State DFI stake

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