RYSTAD ENERGY

OG21 STRATEGY REVISION

SUPPORTING REPORT

MAY/JUNE 2021

OG21

Report contents

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Two key realizations – a dual and parallel technology strategy must be applied

1 Continued technology adoption is needed to maintain NCS ability to create value in an increasingly competitive landscape with less demand for fossil fuels

Based on the remaining resources/future activity the following technologies should be prioritized:

- *Technologies to target existing fields and topside infrastructure*
- *Technologies to target tie-backs*

An accelerated energy transition also implies that the following technologies should be prioritized:

- *Technologies that can be adopted quickly (demand projections decline rapidly post 2030)*
- *Technologies that reduce scope 1 emissions (will increase in importance with increased CO_2 costs)*

Volumes

Net volume additions
RRR
Discovery rates
Lead time
RP ratios
Recovery rates
Average discovery size
Materiality (NPV/DPI)
Sanctioned volumes

Costs

Opex per boe
P&A cost per well
P&A duration
Expex per boe
IRR
Capex per boe
Break-even prices

Upstream emissions

Extraction emission intensity
Total upstream emissions
Flaring intensity
Drilling emission intensity

2 A proactive approach must be taken to position NCS for new energy markets by leveraging current capabilities

- *Oil and gas competences are highly complementary to several of the new energy markets*
- *Fit for Norway is not necessarily Fit for 55 (EU) as they have competing solutions for the energy transition.*
- *Brexit implies losing an energy voice similar to Norway in EU foras (blue hydrogen, CCUS , floating wind).*
- *Longer distance to market (transportation costs and losses) may prove a disadvantage if we do not utilize existing infrastructure*

New industry opportunities

Gas to wire
Blue hydrogen / ammonia
CCUS
Floating offshore wind
Offshore smart grid
Marine minerals

Pace of energy transition shifts focus to the right

Report summary in written (1/2)

Key observation	Comments
The energy transition is underway, reflected by stakeholder views, prices of renewables and general sentiment	• While most energy forecasters envisaged peak oil demand well beyond 2030 in their previously published views (pre-Covid), they have now shifted to envisaging peak oil in the early 2020s or 2030s. Most stakeholders' scenarios which assume the 2-degree target to be reached have this as a prerequisite. • Meanwhile, stakeholders predict a later peak for gas globally. Still, the EU, Norwegian gas' most important importer, states that peak gas demand in the EU28 to already have happened. • Many stakeholders also regard successful rollout of CCS as a prerequisite to reach the 2-degree target. • 60% of global oil demand is related to the transportation sector. Light modes of transportation like cars are most likely to replace demand for oil with a combination of renewable power and batteries. Heavy modes like trucks, ships and airplanes will likely rely more on hydrogen fueling. • Hydrogen will also be a key component in displacing gas, as it is a needed storage element to compensate for the concept of intermittency from renewable power. In general, efficient and scaled energy storage is currently the largest challenge for a full-scale rollout of renewable energy; while battery value chains are squeezed based on access to minerals, hydrogen technology is still immature. Besides this, new capacity of renewable power is now cost competitive with new fossil power. • The energy transition poses a set of challenges, but also opportunities for continued operations on the NCS. Challenges include 1) Access to capital, increasingly flowing towards green energy instead of oil and gas, and 2) Access to renewable power from shore, which sentiment may prefer in the hands of power intensive green industries. Meanwhile, opportunities exist in new energy markets like Floating wind, CCS and blue hydrogen.
Metrics on NCS display varying degrees of competitiveness, yet with strong performance on lifting cost and emissions intensity	• NCS competitiveness has been assessed from three perspectives: ability to discover and mature volumes, to develop and operate them cost efficiently and with low upstream emissions intensity • The NCS displays varying performance on ability to find and mature new volumes depending on the metric used. While the probability of a well leading to discovery is high, the average size of discoveries is small. Ability to maximize brownfield volume potential is reflected in high recovery rate (46%), which again contributes to a relatively high overall reserve replacement ratio of 70%. • In terms of lead times from FID to first production, the NCS scores in the middle of the pack among peers with an average of 4 years. Subsea tie-back lead time pulls the average down at about 2 years, but not enough to compete with shale and conventional onshore volumes with less than one year. • Maximizing the availability of brownfield and near-infrastructure volumes is identified as areas of impact. The same is the case for enabling tie-back volumes. • On cost metrics, performance is also variable. The NCS has high expex and capex per boe compared to peers (5 and 9 USD/boe, respectively), but very competitive opex per boe (4 USD/boe). This culminates in favorable breakeven costs overall. This advantage related to opex per boe (lifting costs) is highly contingent on high production levels however, meaning it will deteriorate over time if costs remain stable while production naturally declines. Cost reduction related to drilling, facility development, maintenance and operations is thus needed to stay ahead. • Meanwhile, P&A costs on the NCS are in the higher end among peers, likely party due to more stringent regulatory standards. • The NCS is world leading on emissions intensity with 7 kg CO2 per boe. Still, reaching industry ambitions of 40%-50% reduction in emissions by 2030 will require considerable effort; all publicized electrification efforts will only contribute to about half of the ambition and alternate ways to negate turbine emissions should be considered. Similar to lifting costs, emissions intensity is bound to increase naturally as production declines. Emissions tend to remain stable on fields as oil and gas production falls. Water production and injection is identified as a large contributor to NCS emissions, being responsible for about half of the turbine power on oil fields.

Source: Rystad Energy research and analysis

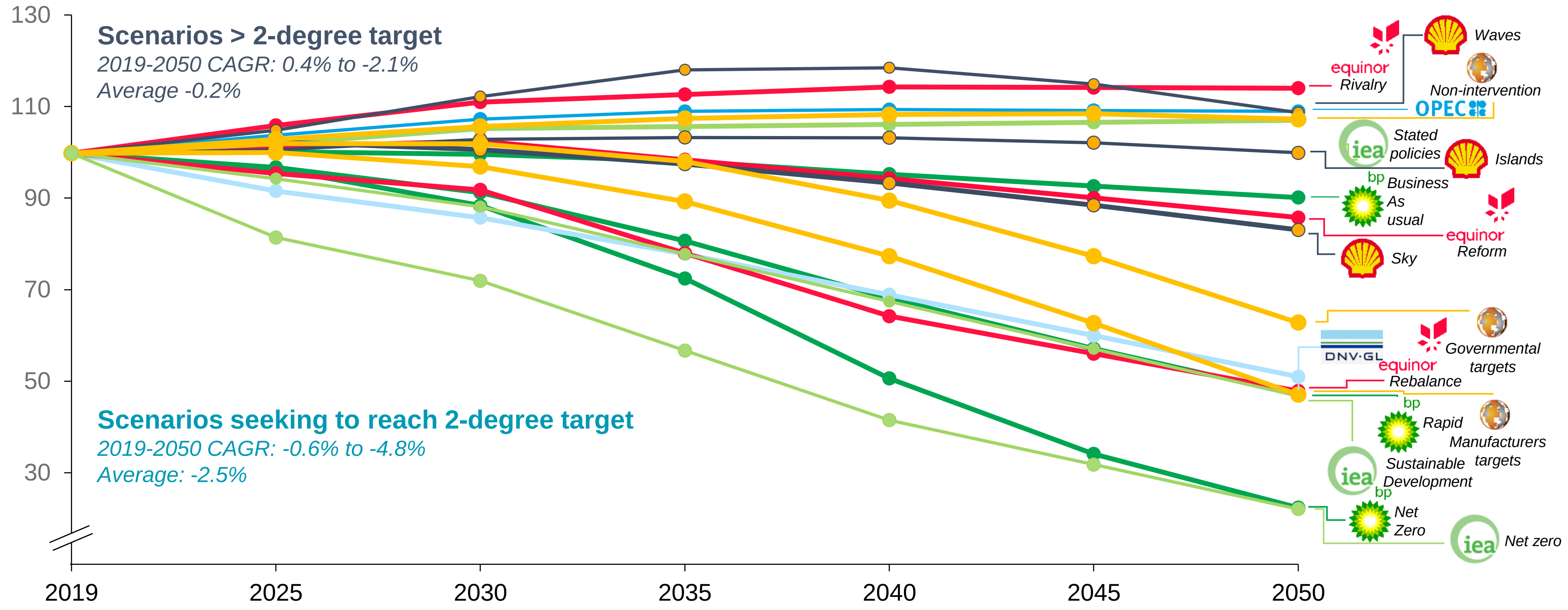
Report summary in written (2/2)

Key observation	Comments
A wide range of technologies are needed to maintain competitiveness, 28 opportunities have been identified and assessed	• An initial round of workshops has been followed by expert interviews before a second round of workshops has led to a short list of 28 technology or knowledge opportunities related to improving competitiveness within NCS oil and gas extraction. Each opportunity has been given an assessment of its potential to improve safety, volumes, costs, emissions and export value for the service industry. • No single opportunity is enough to secure NCS competitiveness, several are needed. Furthermore, not all 28 are guaranteed to be viable for scaled implementation, adding to the notion of there not being one «silver bullet» technology. • Out of the 28 opportunities, 25 receive a clear-cut recommendation from Rystad Energy. Another 2 are identified as having high potential but also significant obstacles in the way of being realized, they are «Offshore CO2 storage and late-life deposits» and «Standardized subsea templates». A final opportunity, «[Drilling in] Tight and homogeneous reservoirs» is seen as having a sizable volume contribution, but not one that outweighs negative contributions on costs and emissions. • The largest contributions to increased volumes comes from the opportunities (in descending order) «Subsurface understanding and models», «Data gathering and optimization of drilling operations», «Subsea well intervention technologies», and «Recompletion and multilateral technologies». • Similarly, the largest contributions to cost reductions come from (in descending order) «Digital tools for improved maintenance and more efficient operations», «Standardized subsea templates» and «Unmanned facilities and subsea tie-backs». All three belong to TG4 and relate to «Production, processing and transport». • Finally, the largest contributions to emissions are from «Energy efficiency in offshore operations» and «Offshore carbon capture and storage», relying on improved turbine efficiency and modules for CCS of scope 1 emissions on oil and gas fields, respectively. • Beyond the opportunities leading to direct effects on volumes, costs and emissions, 13 opportunities are identified as being enablers or prerequisites for the others. Enabling opportunities are mostly part of the process of digitalization; while they are necessary for facilitating digitalization applications, they do not lead to significant effects themselves. Examples include improved data gathering and data management, which in turn enable technologies like improved condition-based maintenance. • Prerequisites are opportunities identified as crucial from a safety or social license-to-operate perspective and generally relate to HSE or local emissions. Like enablers, they do not provide direct effect on volumes, costs or emissions, but are still regarded as necessary gaps to address for continued operations in general. • Digitalization is relevant to many of the opportunities identified, being related to 17 of the 28 opportunities identified.
Meanwhile, parallel devotion should be made to new energy markets, which potentially offset declining investments in oil and gas	• Ensuring NCS competitiveness does not maintain its longevity alone. Lack of frontier exploration success and turning hydrocarbon demand means that investments in oil and gas are bound to decline over the next 30 years. • New, more carbon neutral energy markets will potentially rise as oil and gas declines. Blue hydrogen, offshore wind, CCUS and marine minerals have been assessed on ability to replace investment levels in oil and gas. • All these segments have competency overlaps with oil and gas, indicating a Norwegian advantage for them as well. Blue hydrogen is seen as completely overlapping given that it revolves around extraction of gas. CCS has strong overlaps in the domains of seismic, subsea and offshore maintenance. Marine minerals has potential overlaps with marine operations, developments in yards and geology/seismic. Offshore wind has particular overlaps in marine operations and facility maintenance. • Blue hydrogen production in the NCS is not deemed immediately viable and will struggle competitively for the same reason as Norwegian LNG: Transport is expensive and the US East Coast has excess competitive feedstock. A more viable way for blue hydrogen to play a role is as being converted from Norwegian gas on the European continent or the UK. • No single one of the four new energy markets assessed have the potential to offset investment levels in oil and gas. Combined, however, they have the potential to create a new uptick in Norwegian offshore related investments, with early 2020s investment levels being repeated in the 2040s (about 27 BUSD p.a.). It is Rystad Energy's opinion that this warrants attention in the form of R&D into these potential new energy markets • Circular economies is a different way decline in oil and gas extraction can be leveraged. Two forms of re-use of infrastructure have been assessed: the re-use of wells and the re-use of platform jackets. The former has fewer risk elements associated with it and a higher cost saving potential. Wells can be re-used for the purpose of CCS or geothermal energy, provided that knowledge regarding necessary design and integrity considerations is obtained.

Source: Rystad Energy research and analysis

Significant spread in projects for liquids demand going forward – future is uncertain

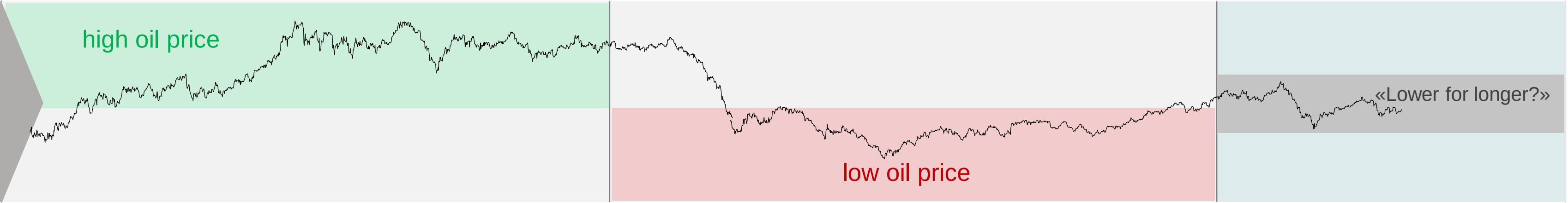
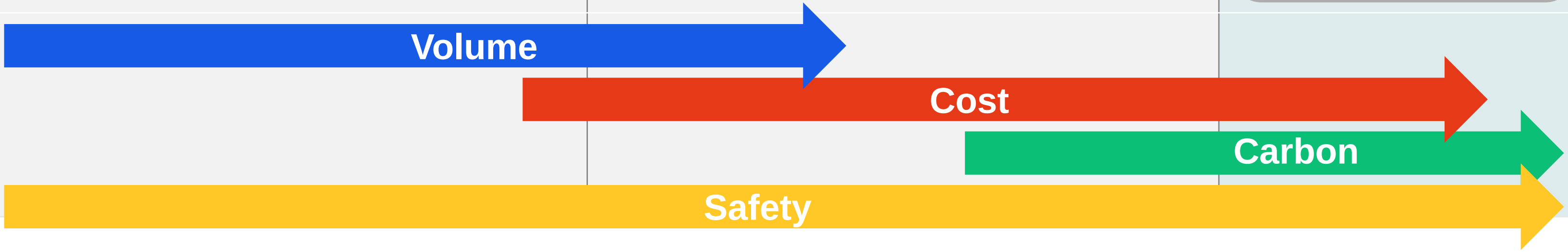
Global liquids demand in different scenarios*
Million boe/d



- The projections for the demand of petroleum liquids vary significantly.
- The liquids demand projections mainly separate into two pathways:
  Scenarios not aiming to reach the 2-degree target, and scenarios that aims to reach this target. The scenarios in the first category has a quite stable forecast, while the scenarios that aims to reach the target projects a steep decline in liquids demand.
- Falling liquids demand imply rapid electrification or efficiency gains in the oil-reliant transport sector, which in turn is dependent on technological development and/or large infrastructure investments.

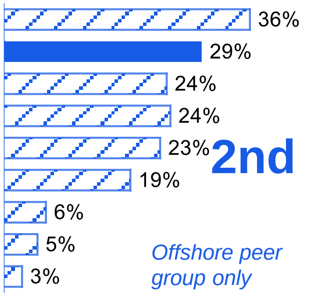
* Indexed to IEA 2019 levels as different providers define units and markets differently EIA not included as they don't have any updated post-COVID scenario, making it less relevant and comparable.
Source: Rystad Energy research and analysis; IEA WEO 2020; Shell Scenarios 2020; OPEC WOO 2020; BP EO 2020; EIA International Energy Outlook 2020; Equinor Energy Perspectives 2020; DNV GL ETO 2020

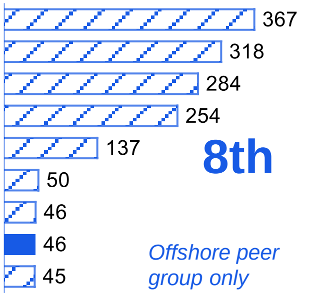
The industry cycles come with new competitive areas – sustainability high on the agenda

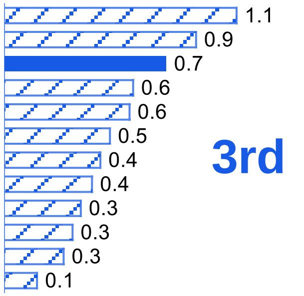
	Upcycle *(2007-2013)*	**Downcycle** *(2014-2018)*	***Future*** *(2019 →)*
Investment themes	**Materiality**	**Robustness**	**Sustainability**
Additional competitiveness metrics	- **Production growth** - **Reserve replacement** - **High value (absolute NPV)**	**Previous metrics and:** **+ Low break-even** **+ Cost-effective production**	**Previous metrics and:** **+ Short payback time** **+ Carbon-effective production**
Price regime			
Investment theme rationale	*Soaring commodity prices and high yields focus investments on the most material projects. DPI* typical measure used in this time frame.*	*Detrimental commodity prices and limited access to capital switched focus from materiality to robustness*	*High commodity price uncertainty and peak demand looming. Public pressure on carbon-intensive industries. Rising CO2 prices*
Communicated focus			

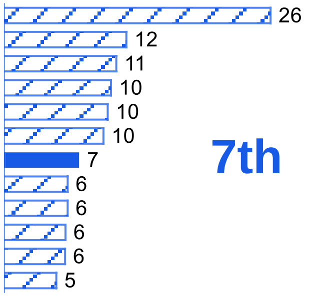
* DPI = Discounted Profitability Index. Source: Rystad Energy research and analysis

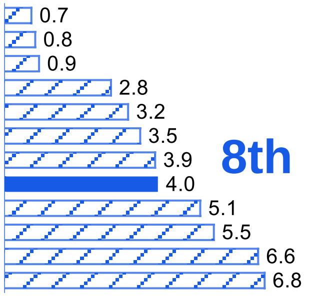
NCS is currently competitive on many metrics, especially on emissions and lifting costs

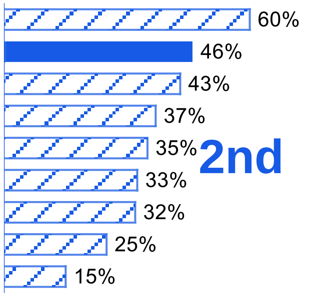

Discovery rate (%)

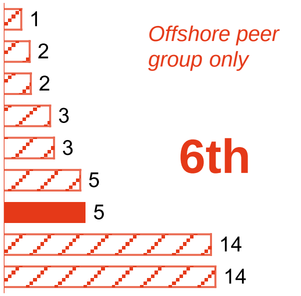

Discovery size (Mmboe)

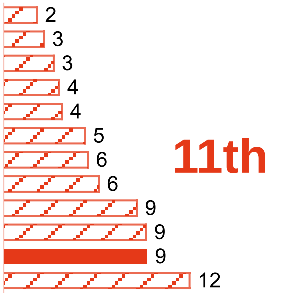

Reserve replacement* (RRR)

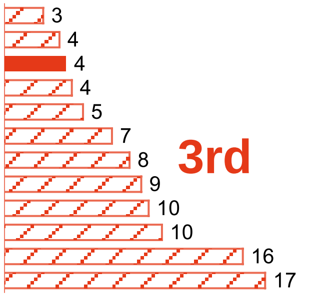

Reserves to Production (RP-ratio)

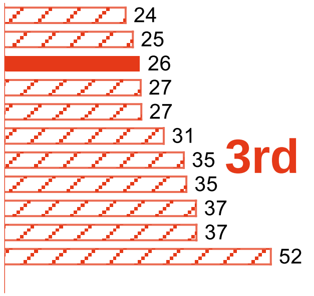

Lead time new fields (years)

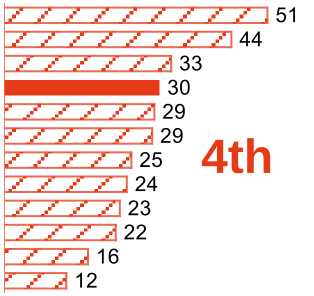

Recovery rate

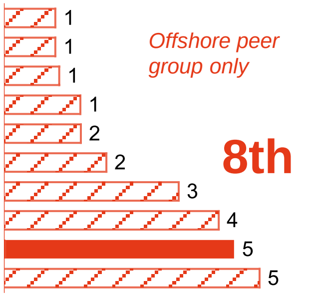

Expex per boe

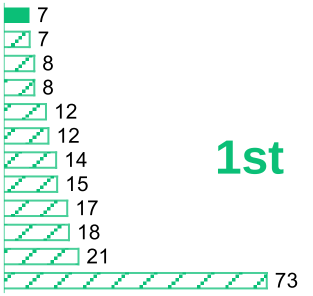

Capex per boe

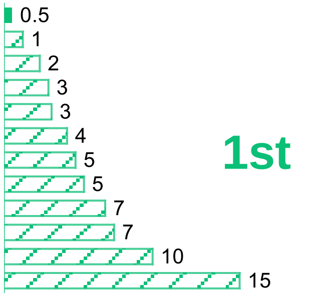

Opex per boe

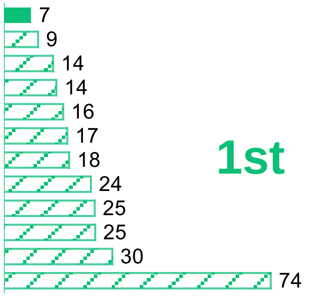

Break-even prices (USD/boe)

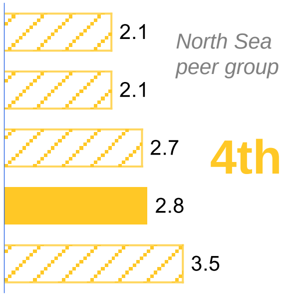

IRR (Percentage)

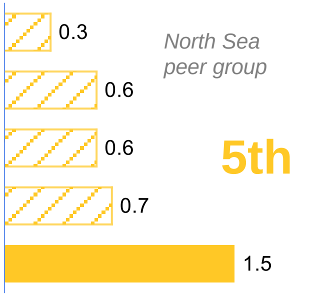

P&A cost per well


Extraction emissions (kg CO2/boe)


Flaring emissions (kg CO2/boe)

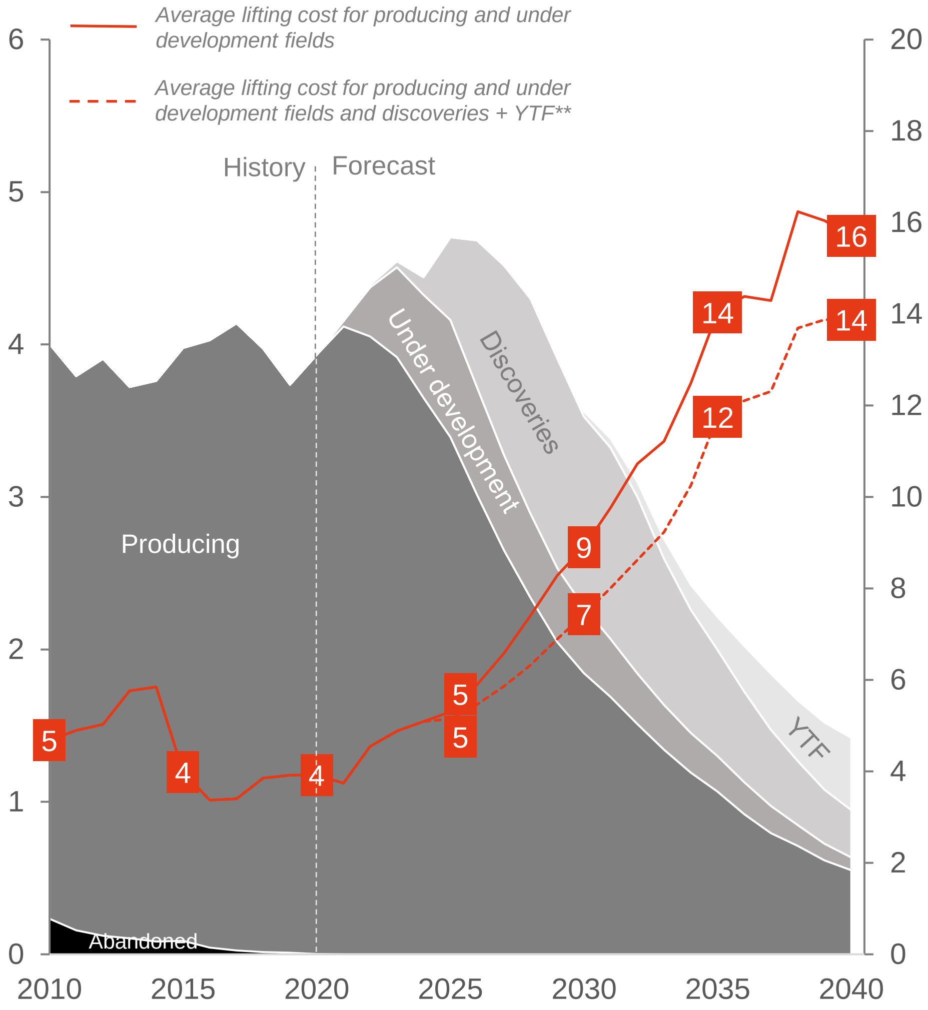

Upstream emissions (kg CO2/boe)


Total recorded injury rate

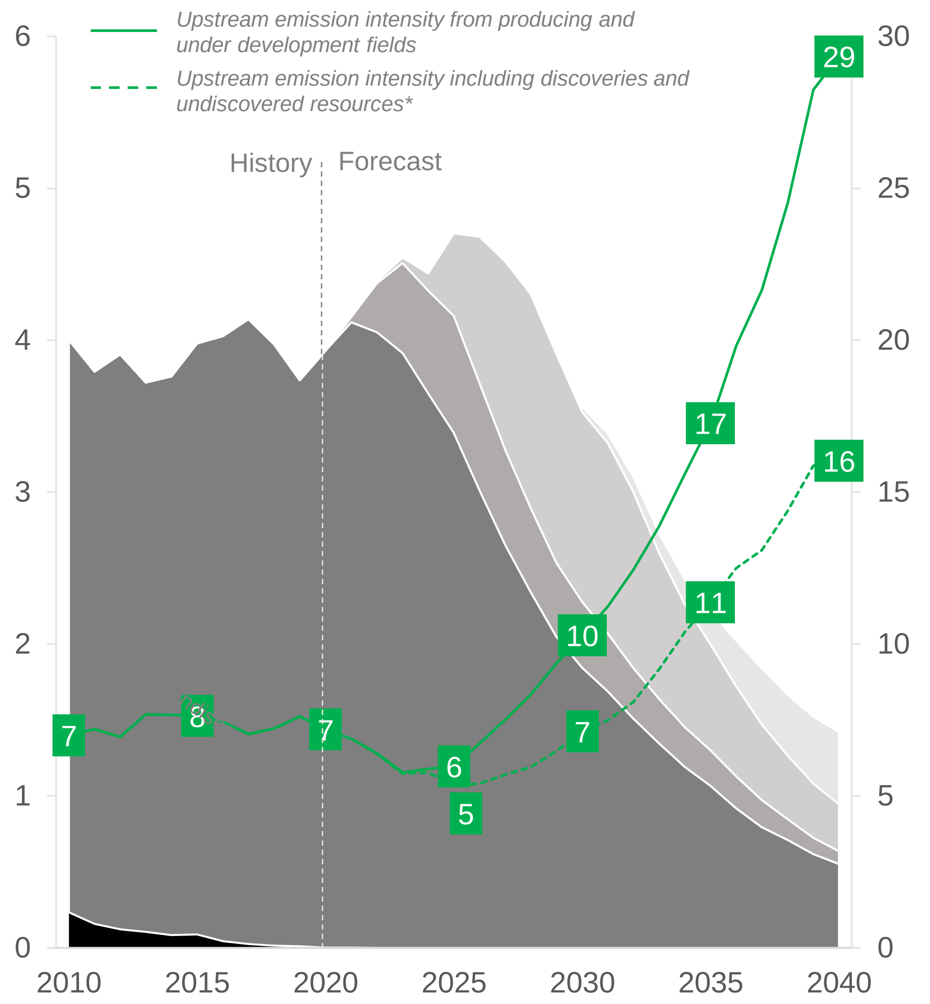

Lost time injury frequency

Competitiveness will not last without application of new technologies

NCS Production **Average lifting cost for NCS**
Mmboe/d Opex per boe produced*



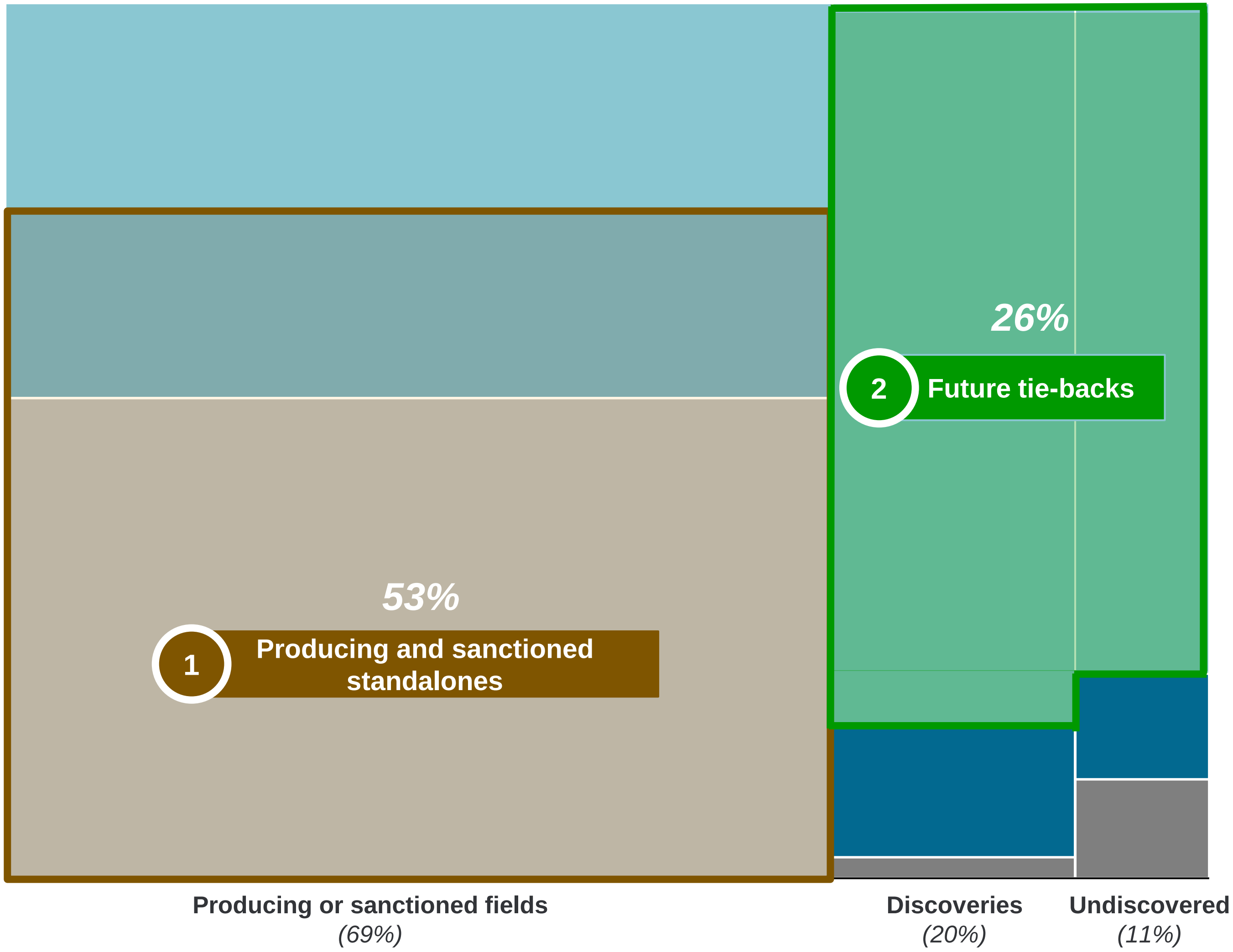
NCS Production **Upstream emission intensity for NCS****
Mmboe/d kg CO2/boe



*Production opex only. SG&A and transportation tariffs not included; **only from opened areas
Source: Rystad Energy UCube

Future activity in two key buckets: existing infrastructure and future tie-backs

Volume buckets on NCS between 2021-2050
Percentage of expected barrels of oil equivalents produced



- Two large key buckets of future production volumes can be defined based on the categories on the previous page; 1) Producing and sanctioned standalones and 2) Future tie-backs.
- The producing and sanctioned standalones consists of volumes already sanctioned as standalone developments with dedicated processing facilities. Technologies that improve recovery in already developed fields will have a large impact on this bucket.
- The future tie-back bucket consists of volumes from fields expected to be developed as subsea/wellhead tie-backs. Technology that enable successful exploration and resource effective development will be important for these volumes.

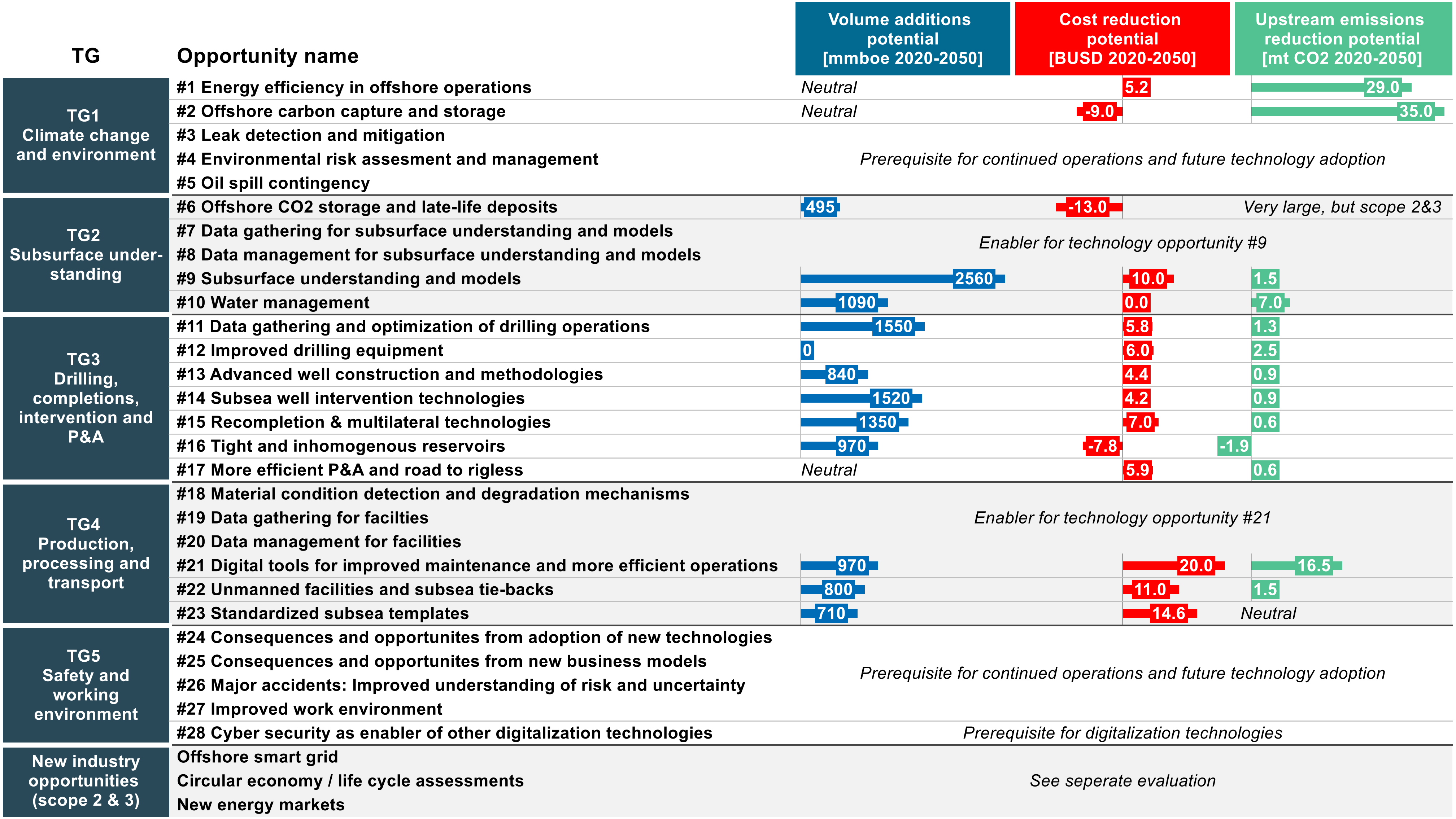
Source: Rystad Energy UCube

31 opportunities identified with ability to retain and improve NCS value creation

TG	Opportunity name	Description
TG1 Climate change and environment	**#1 Energy efficiency in offshore operations**	Energy efficiency technologies to reduce total energy consumption and emissions offshore
	#2 Offshore carbon capture and storage	Small-scale carbon capture topside to reduce turbine emissions
	#3 Leak detection and mitigation	Control of discharges and environmental impact with digital sensory, data analytics and modelling software
	#4 Environmental risk assesment and management	Control of environmental risk assessment and management using digital tools and modelling software
	#5 Oil spill contingency	Maintaining social license to operate by adopting new technologies to reduce risk in case of oil releases
TG2 Subsurface understanding	**#6 Offshore CO2 storage and late-life deposits**	CO2 injection of 3rd party CO2 emissions for enhanced oil recovery
	#7 Data gathering for subsurface understanding and models	Data management systems and infrastructure, new modelling approaches and data flow
	#8 Data management for subsurface understanding and models	Technologies and knowledge that improves the input that goes into the models
	#9 Subsurface understanding and models	Improved reservoir models as a result of input and processes, leading to more efficient and accurate operations
	#10 Water management	Improved water management for reduced emissions and increased recovery
TG3 Drilling, completions, intervention and P&A	**#11 Data gathering and optimization of drilling operations**	New sensory input and improved data systems, resulting in more efficient operations
	#12 Improved drilling equipment	Improved drilling equipment such as improved BoP and hybrid technologies
	#13 Advanced well construction and methodologies	Technologies and knowledge associated with improved well construction
	#14 Subsea well intervention technologies	Subsea well intervention technologies to reduce cost and increase safety
	#15 Recompletion & multilateral technologies	Technologies associated with better utilization of existing wells
	#16 Tight and inhomogenous reservoirs	Technologies for recovering tight and/or inhomogeneous reservoirs
	#17 More efficient P&A and road to rigless	Enabling rigless P&A on the NCS
TG4 Production, processing and transport	**#18 Material condition detection and degradation mechanisms**	Improved knowledge and understanding of material condition detection and degradation mechanisms
	#19 Data gathering for facilties	Adoption of new sensory technologies for people-less operations and improved monitoring
	#20 Data management for facilities	Adoption of data management tools to improve integrity monitoring an maintenance planning
	#21 Digital tools for improved maintenance and more efficient operations	Adoption of digital tools for improved monitoring and introduction of condition-based maintenance
	#22 Unmanned facilities and subsea tie-backs	Technologies to improve commerciality of smaller discoveries and utilize existing hosts
	#23 Standardized subsea templates	Standardization of subsea modules to reduce development cost and shorten lead time
TG5 Safety and working environment	**#24 Consequences and opportunites from adoption of new technologies**	Improved understanding of the HSE effects related to digitalization, new power sources for facilities and more
	#25 Consequences and opportunites from new business models	Improved knowledge and understanding of new contract schemes, player landscapes and KPIs
	#26 Major accidents: Improved understanding of risk and uncertainty	Improved indentification and understanding of root casues for major accidents and their consequenses
	#27 Improved work environment	Improved knowledge and understanding of long term hazards from working environment, long and short term
	#28 Cyber security as enabler of other digitalization technologies	Knowledge and technology to keep up with the increasing pace and relevance of cyber security threats
New industry opportunities (scope 2 & 3)	**Offshore smart grid**	Interconnecting oil and gas installations with other energy systems to electrify and economize power consumption
	Circular economy / life cycle assessments	New energy markets with the ability to offset decline in O&G spending
	New energy markets	Comparisons between scope 1 emissions and footprint of procured materials/components

Source: Rystad Energy research and analysis

No silver bullet, a wide range of technologies needed to improve NCS competitiveness



TG	Opportunity name	Volume additions potential [mmboe 2020-2050]	Cost reduction potential [BUSD 2020-2050]	Upstream emissions reduction potential [mt CO2 2020-2050]
TG1 Climate change and environment	**#1 Energy efficiency in offshore operations**	*Neutral*	5.2	29.0
	#2 Offshore carbon capture and storage	*Neutral*	-9.0	35.0
	#3 Leak detection and mitigation	*Prerequisite for continued operations and future technology adoption*		
	#4 Environmental risk assesment and management			
	#5 Oil spill contingency			
TG2 Subsurface under-standing	**#6 Offshore CO2 storage and late-life deposits**	495	-13.0	*Very large, but scope 2&3*
	#7 Data gathering for subsurface understanding and models	*Enabler for technology opportunity #9*		
	#8 Data management for subsurface understanding and models			
	#9 Subsurface understanding and models	2560	10.0	1.5
	#10 Water management	1090	0.0	7.0
TG3 Drilling, completions, intervention and P&A	**#11 Data gathering and optimization of drilling operations**	1550	5.8	1.3
	#12 Improved drilling equipment	0	6.0	2.5
	#13 Advanced well construction and methodologies	840	4.4	0.9
	#14 Subsea well intervention technologies	1520	4.2	0.9
	#15 Recompletion & multilateral technologies	1350	7.0	0.6
	#16 Tight and inhomogenous reservoirs	970	-7.8	-1.9
	#17 More efficient P&A and road to rigless	*Neutral*	5.9	0.6
TG4 Production, processing and transport	**#18 Material condition detection and degradation mechanisms**	*Enabler for technology opportunity #21*		
	#19 Data gathering for facilties			
	#20 Data management for facilities			
	#21 Digital tools for improved maintenance and more efficient operations	970	20.0	16.5
	#22 Unmanned facilities and subsea tie-backs	800	11.0	1.5
	#23 Standardized subsea templates	710	14.6	*Neutral*
TG5 Safety and working environment	**#24 Consequences and opportunites from adoption of new technologies**	*Prerequisite for continued operations and future technology adoption*		
	#25 Consequences and opportunites from new business models			
	#26 Major accidents: Improved understanding of risk and uncertainty			
	#27 Improved work environment			
	#28 Cyber security as enabler of other digitalization technologies	*Prerequisite for digitalization technologies*		
New industry opportunities (scope 2 & 3)	**Offshore smart grid**	*See seperate evaluation*		
	Circular economy / life cycle assessments			
	New energy markets			

Source: Rystad Energy research and analysis

Opportunities mostly recommended based on calc.s of potentials, yet with three exceptions

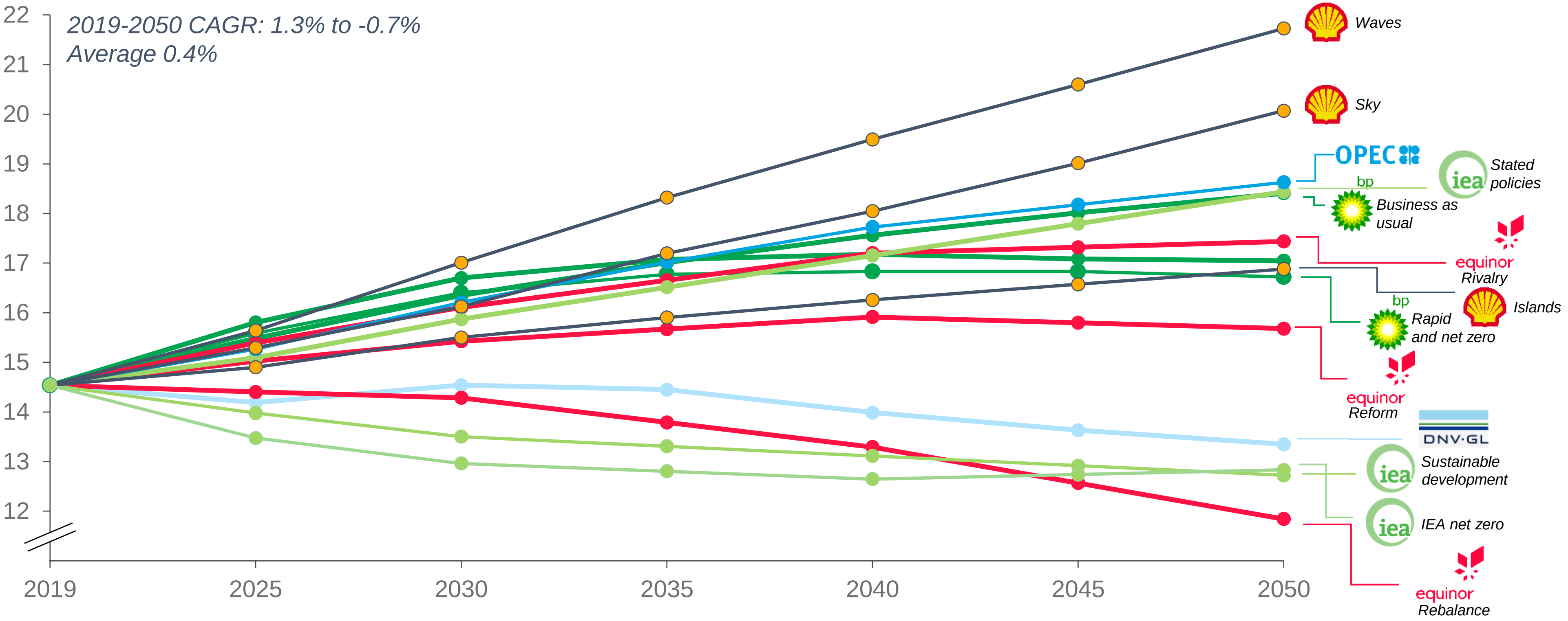
TG	Opportunity name	Advised role in strategy revision	
TG1 Climate change and environment	#1 Energy efficiency in offshore operations	🟩	Large emission reduction potential and positive cost contribution
	#2 Offshore carbon capture and storage	🟩	Likely needed to reach long term emissions targets, but challenging topside conditions
	#3 Leak detection and mitigation	🟩	Prerequisite for continued operations and social lisence to operate
	#4 Environmental risk assesment and management	🟩	Prerequisites for continued operations, failure with potentially devastating effect on social lisence to operate
	#5 Oil spill contingency	🟩	
TG2 Subsurface under-standing	#6 Offshore CO2 storage and late-life deposits	🟨	Refocus to be a part of cessation plans. 3rd party CO2 shippers unlikely to approve EOR applications
	#7 Data gathering for subsurface understanding and models	🟩	Enabler for unlocking increasingly elusive NCS volumes through faster and better modelling and understanding. Largest volume contribution in list and with positive cost contribution
	#8 Data management for subsurface understanding and models	🟩	
	#9 Subsurface understanding and models	🟩	
	#10 Water management	🟩	Adresses one of the largest sources of turbine power on NCS. Considerable emissions impact
TG3 Drilling, completions, intervention and P&A	#11 Data gathering and optimization of drilling operations	🟩	Positive contribution on all primary effects (volumes, costs, emissions), highly brownfield relevant
	#12 Improved drilling equipment	🟩	Beyond moderate positive effect on costs and emissions a high contribution to safety is expected
	#13 Advanced well construction and methodologies	🟩	Positive contribution on all primary effects (volumes, costs, emissions), highly brownfield relevant
	#14 Subsea well intervention technologies	🟩	Opens door for fast, cheap increases in production in existing and future fields
	#15 Recompletion & multilateral technologies	🟩	More efficient well construction gives modest volume and cost benefits
	#16 Tight and inhomogenous reservoirs	🟥	Positive volume impact, but at the expense of higher cost and more emissions than other volumes
	#17 More efficient P&A and road to rigless	🟩	Increases cost efficiency of pending ncs P&A commitment
TG4 Production, processing and transport	#18 Material condition detection and degradation mechanisms	🟩	Enabler prolonged life of fields as safety and integrity is ensured
	#19 Data gathering for facilties	🟩	Enabler for further digitalization of NCS facilities and remaining competitive on opex/safety
	#20 Data management for facilities	🟩	
	#21 Digital tools for improved maintenance and more efficient operations	🟩	Largest cost contribution from single opportunity given prospective reduced maintenance scope
	#22 Unmanned facilities and subsea tie-backs	🟩	Allows for developments not feasible today: restraints related to economics/distance alleviated
	#23 Standardized subsea templates	🟨	Sizable potential, yet limited scale of subsea industry draws prospect of cost savings into question
TG5 Safety and working environment	#24 Consequences and opportunites from adoption of new technologies	🟩	Prerequisites for continued operations and social license to operate and enabler for adoption of other digitalization technologies.
	#25 Consequences and opportunites from new business models	🟩	
	#26 Major accidents: Improved understanding of risk and uncertainty	🟩	
	#27 Improved work environment	🟩	
	#28 Cyber security as enabler of other digitalization technologies	🟩	
New industry opportunities (scope 2 & 3)	Offshore smart grid	🟩	Pathway to reaching upstream emission targets by leveraging new energy and storage solutions
	Circular economy / life cycle assessments	🟩	Sizable potential, especially related to the re-use of wells for other well intensive industries
	New energy markets	🟩	Competence overlaps with O&G, will be vital to secure the longevity of the Norwegian offshore industry

Source: Rystad Energy research and analysis

Report contents

Projected total global energy demand vary widely between scenarios

Total Primary Energy Demand (TPED) of different scenarios*
Gigatonne of oil equivalent



2019-2050 CAGR: 1.3% to -0.7%
Average 0.4%

- Total Primary Energy Demand (TPED) is a common measure of global energy demand, and it is an important metric in any future scenario.
- Numerous scenarios are available from different corporations, research institutions and agencies.
- Some scenarios are best-estimates; other merely explore possible pathways given a set of assumptions and goals.
- The chart displays the development of TPED in 14 widely discussed scenarios from 6 well known providers.
- Evident is the large spread in future energy demand, reflective of the different approaches and broad set of assumptions in each scenario.

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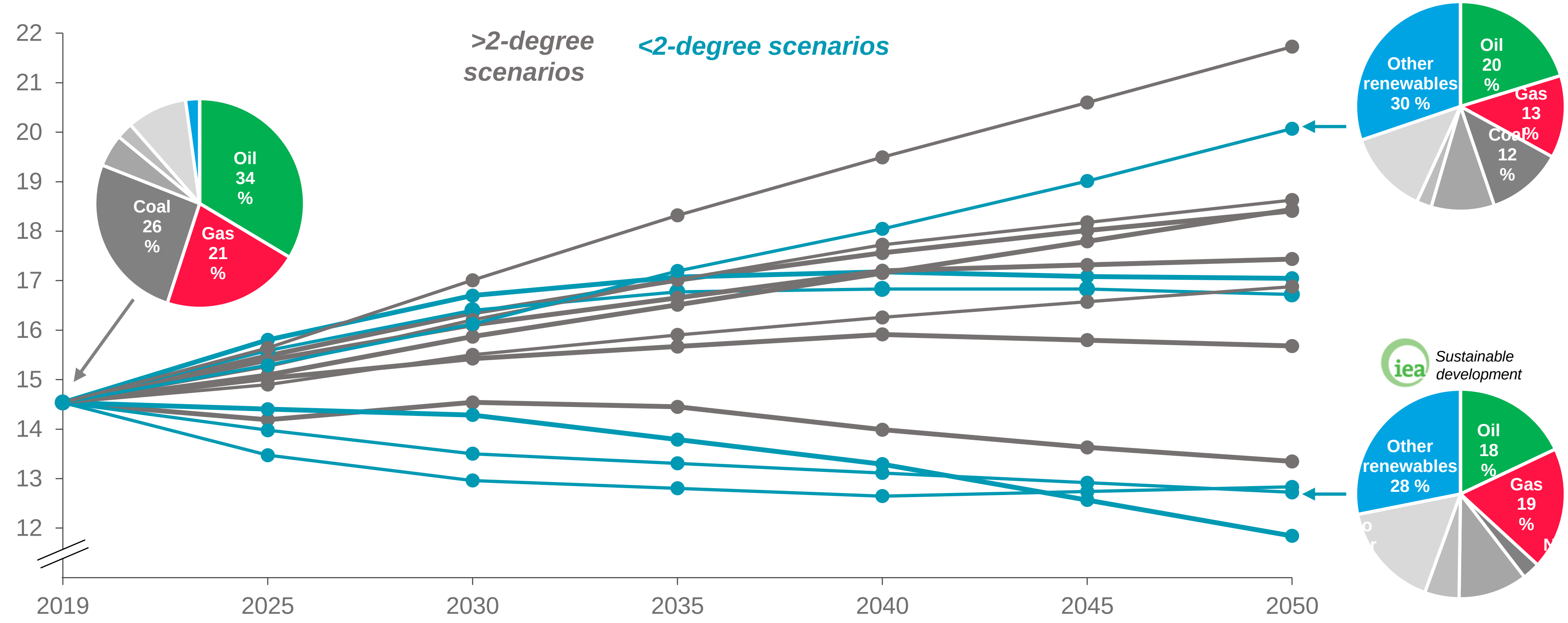
* Indexed to IEA 2019 levels as different providers define units and markets differently. Oil and gas indexed to Rystad total demand 2019. EIA not included as they don't have any updated post-COVID scenario, making it less relevant and comparable. Source: Rystad Energy research and analysis; IEA WEO 2020; Shell Scenarios 2020; OPEC WOO 2020; BP EO 2020; EIA International Energy Outlook 2020; Equinor Energy Perspectives 2020; DNV GL ETO 2020

Scenarios aiming to reach the 2-degree scenario sees strong growth in renewables

Total Primary Energy Demand (TPED) of different scenarios*
Gigatonne of oil equivalent



- Comparing the scenarios that aim to reach the 2-degree target, they vary to what extent they see total primary energy increase or decrease. As exemplified by the Shell Sky scenario, a high energy demand can still be feasible if it is matched by a high share of renewables and CCS.
- The scenarios that aim to meet the 2-degree target are characterized by a significantly lower fossil fuel share, as well as a strong growth in the renewable share.

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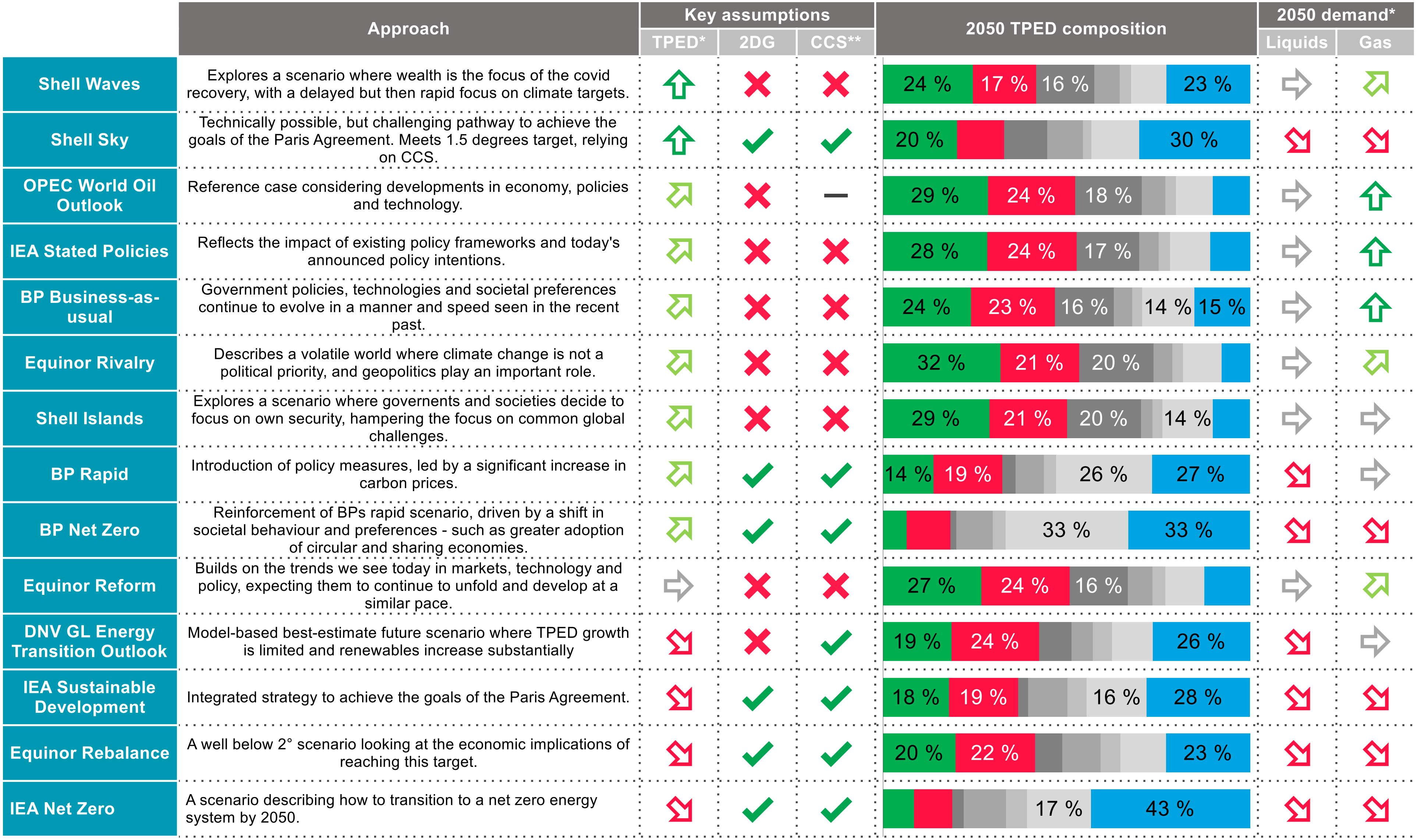
* Indexed to IEA 2019 levels as different providers define units and markets differently. Oil and gas indexed to Rystad total demand 2019. EIA not included as they don't have any updated post-COVID scenario, making it less relevant and comparable. Source: Rystad Energy research and analysis; IEA WEO 2020; Shell Scenarios 2020; OPEC WOO 2020; BP EO 2020; EIA International Energy Outlook 2020; Equinor Energy Perspectives 2020; DNV GL ETO 2020

TPED composition category						
Oil	Gas	Coal	Nuclear	Hydro	Bioenergy	Other renewables

Scenarios are representations of the future, with differing pathways to achieve the objectives



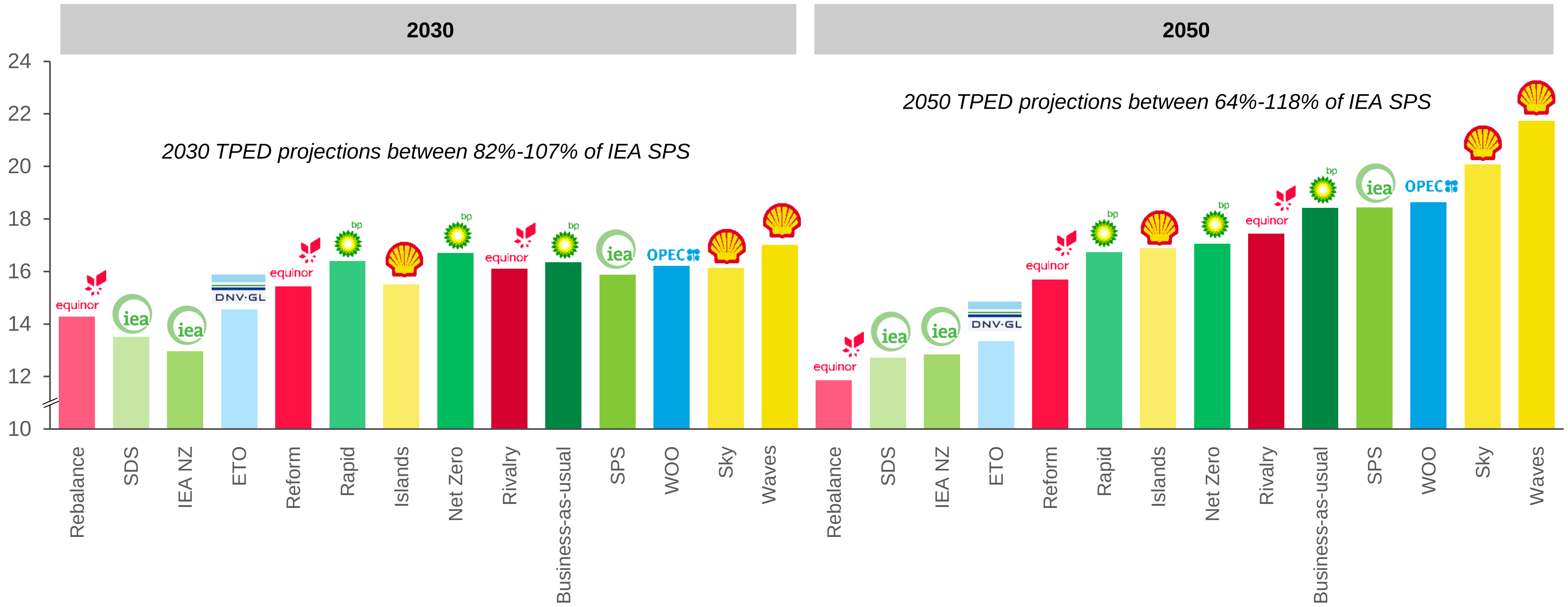
	Approach	Key assumptions			2050 TPED composition	2050 demand*	
		TPED*	2DG	CCS**		Liquids	Gas
Shell Waves	Explores a scenario where wealth is the focus of the covid recovery, with a delayed but then rapid focus on climate targets.	⇧	✗	✗	24 % 17 % 16 % 23 %	⇨	⬀
Shell Sky	Technically possible, but challenging pathway to achieve the goals of the Paris Agreement. Meets 1.5 degrees target, relying on CCS.	⇧	✓	✓	20 % 30 %	⬂	⬂
OPEC World Oil Outlook	Reference case considering developments in economy, policies and technology.	⬀	✗	—	29 % 24 % 18 %	⇨	⇧
IEA Stated Policies	Reflects the impact of existing policy frameworks and today's announced policy intentions.	⬀	✗	✗	28 % 24 % 17 %	⇨	⇧
BP Business-as-usual	Government policies, technologies and societal preferences continue to evolve in a manner and speed seen in the recent past.	⬀	✗	✗	24 % 23 % 16 % 14 % 15 %	⇨	⇧
Equinor Rivalry	Describes a volatile world where climate change is not a political priority, and geopolitics play an important role.	⬀	✗	✗	32 % 21 % 20 %	⇨	⬀
Shell Islands	Explores a scenario where governents and societies decide to focus on own security, hampering the focus on common global challenges.	⬀	✗	✗	29 % 21 % 20 % 14 %	⇨	⇨
BP Rapid	Introduction of policy measures, led by a significant increase in carbon prices.	⬀	✓	✓	14 % 19 % 26 % 27 %	⬂	⇨
BP Net Zero	Reinforcement of BPs rapid scenario, driven by a shift in societal behaviour and preferences - such as greater adoption of circular and sharing economies.	⬀	✓	✓	33 % 33 %	⬂	⬂
Equinor Reform	Builds on the trends we see today in markets, technology and policy, expecting them to continue to unfold and develop at a similar pace.	⇨	✗	✗	27 % 24 % 16 %	⇨	⬀
DNV GL Energy Transition Outlook	Model-based best-estimate future scenario where TPED growth is limited and renewables increase substantially	⬂	✗	✓	19 % 24 % 26 %	⬂	⇨
IEA Sustainable Development	Integrated strategy to achieve the goals of the Paris Agreement.	⬂	✓	✓	18 % 19 % 16 % 28 %	⬂	⬂
Equinor Rebalance	A well below 2° scenario looking at the economic implications of reaching this target.	⬂	✓	✓	20 % 22 % 23 %	⬂	⬂
IEA Net Zero	A scenario describing how to transition to a net zero energy system by 2050.	⬂	✓	✓	17 % 43 %	⬂	⬂

* Indexed to IEA 2019 levels as different providers define units and markets differently. Oil and gas indexed to Rystad total demand 2019 **Green checkmark indicates that CCS plays a significant role. Source: Rystad Energy research and analysis; IEA WEO 2020; Shell Scenarios 2020; OPEC WOO 2020; BP EO 2020; EIA International Energy Outlook 2020; Equinor Energy Perspectives 2020; DNV GL ETO 2020

TPED composition category						
🟩 Oil	🟥 Gas	Coal	Nuclear	Hydro	Bioenergy	🟦 Other renewables

Scenarios differ in total energy demand in the long term – mostly in line short term

Total Primary Energy Demand (TPED) of different scenarios*
Gigatonne of oil equivalent



2030 TPED projections between 82%-107% of IEA SPS

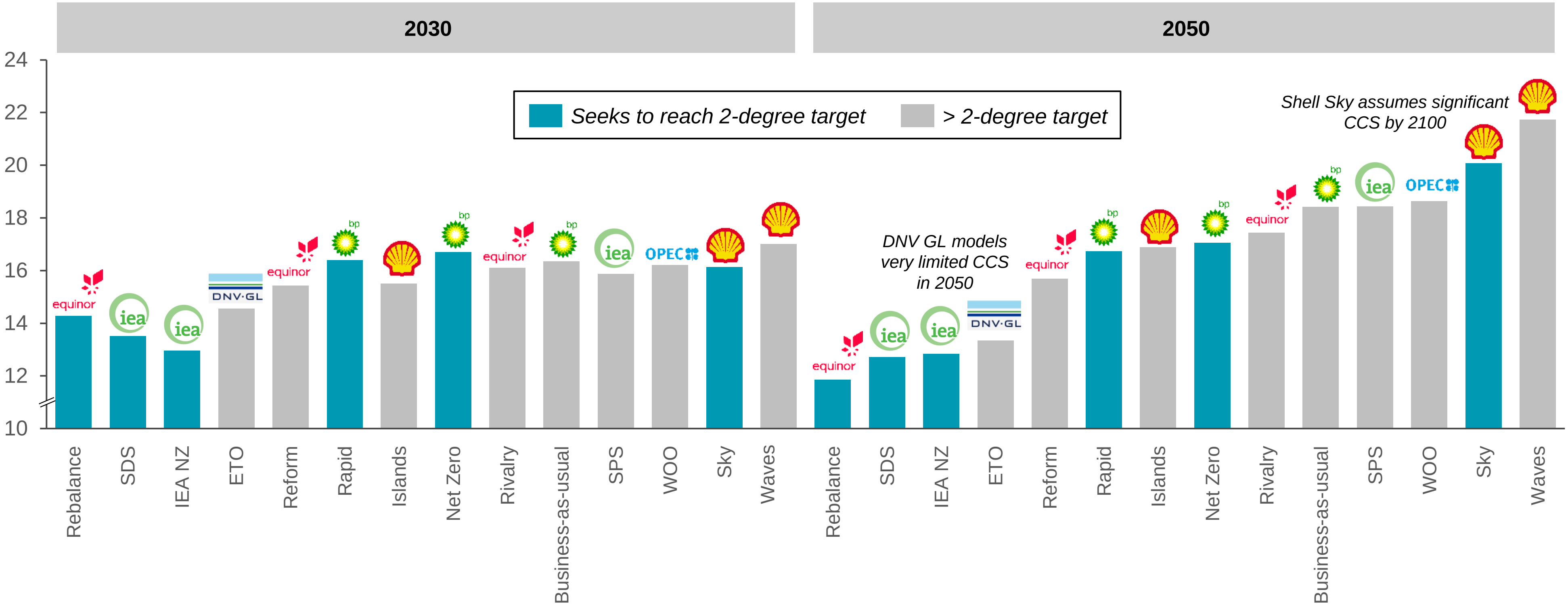
2050 TPED projections between 64%-118% of IEA SPS

- The variation in TPED projections naturally increase with time as assumed developments in GDP, policy, technology and infrastructure take time to manifest.
- Projections for 2030 vary less than projections for 2050; 2030-projections all lie in a ~20% range of IEA SDS, while the range for 2050-projections is ~35%.
- Generally, scenarios seeking a more sustainable future, project lower future TPED compared to “business as usual” scenarios.

* Indexed to IEA 2019 levels as different providers define units and markets differently. Oil and gas indexed to Rystad total demand 2019. EIA not included as they don’t have any updated post-COVID scenario, making it less relevant and comparable . Source: Rystad Energy research and analysis; IEA WEO 2020; Shell Scenarios 2020; OPEC WOO 2020; BP EO 2020; EIA International Energy Outlook 2020; Equinor Energy Perspectives 2020; DNV GL ETO 2020

Total energy demand is not decisive in reaching sustainable targets

Total Primary Energy Demand (TPED) of different scenarios*
Gigatonne of oil equivalent



- Scenarios compliant with the <2DG goal of the Paris Agreement are generally in the lower range of projected TPED, with the exception of Shell's Sky-scenario.
- The Shell Sky scenario is also set up to reach the desired 1.5 degrees target. The scenario models high energy demand. However, with significant carbon capture and storage in the second half of the century.
- DNV GL ETO project 2050 TPED-levels in line with the Paris Agreement-compliant scenarios from Equinor and IEA; but is not itself compliant. This scenario is a best estimate, not a 2-degree scenario
- BP's Rapid scenario is among the scenarios that estimates the lowest liquids demand. However, projected energy demand in 2050 is in the mid range relative to other scenarios.

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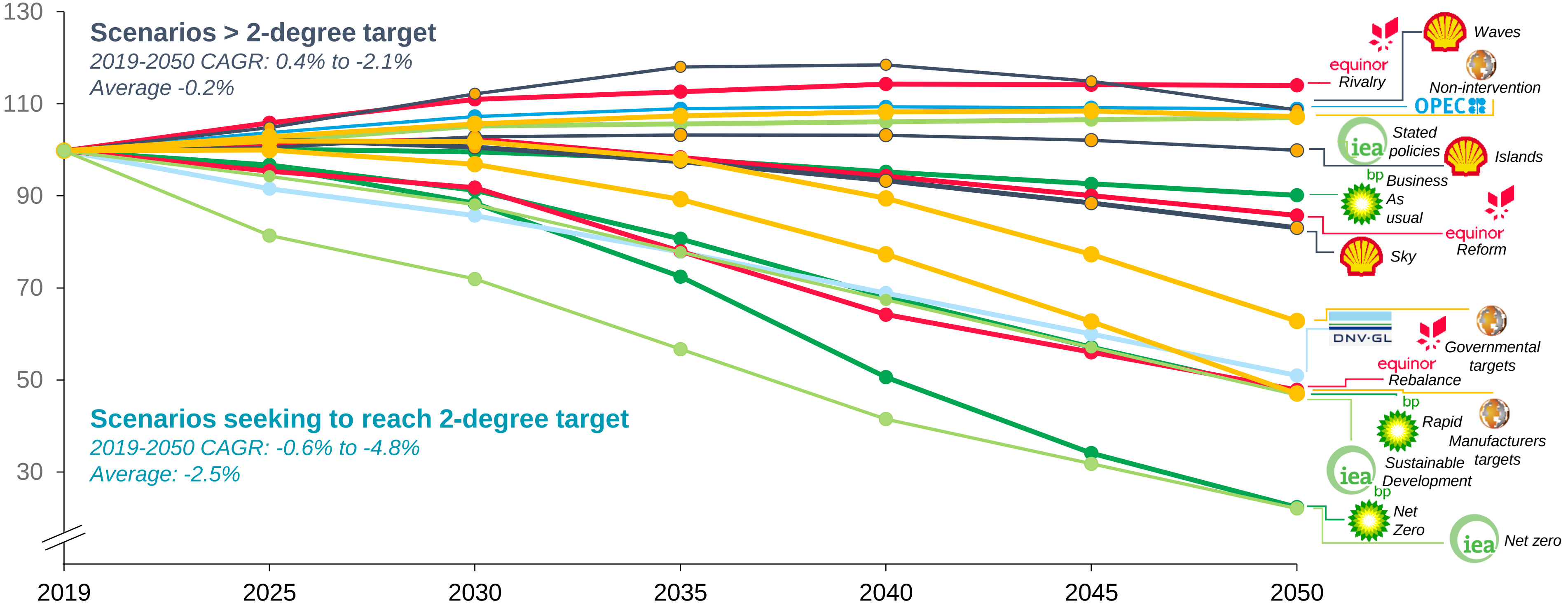
* Indexed to IEA 2019 levels as different providers define units and markets differently. Oil and gas indexed to Rystad total demand 2019. EIA not included as they don't have any updated post-COVID scenario, making it less relevant and comparable. Total demand utilized for oil and gas Source: Rystad Energy research and analysis; IEA WEO 2020; Shell Scenarios 2020; OPEC WOO 2020; BP EO 2020; EIA International Energy Outlook 2020; Equinor Energy Perspectives 2020; DNV GL ETO 2020

Scenarios describe two main pathways for liquids demand

Global liquids demand in different scenarios*
Million boe/d

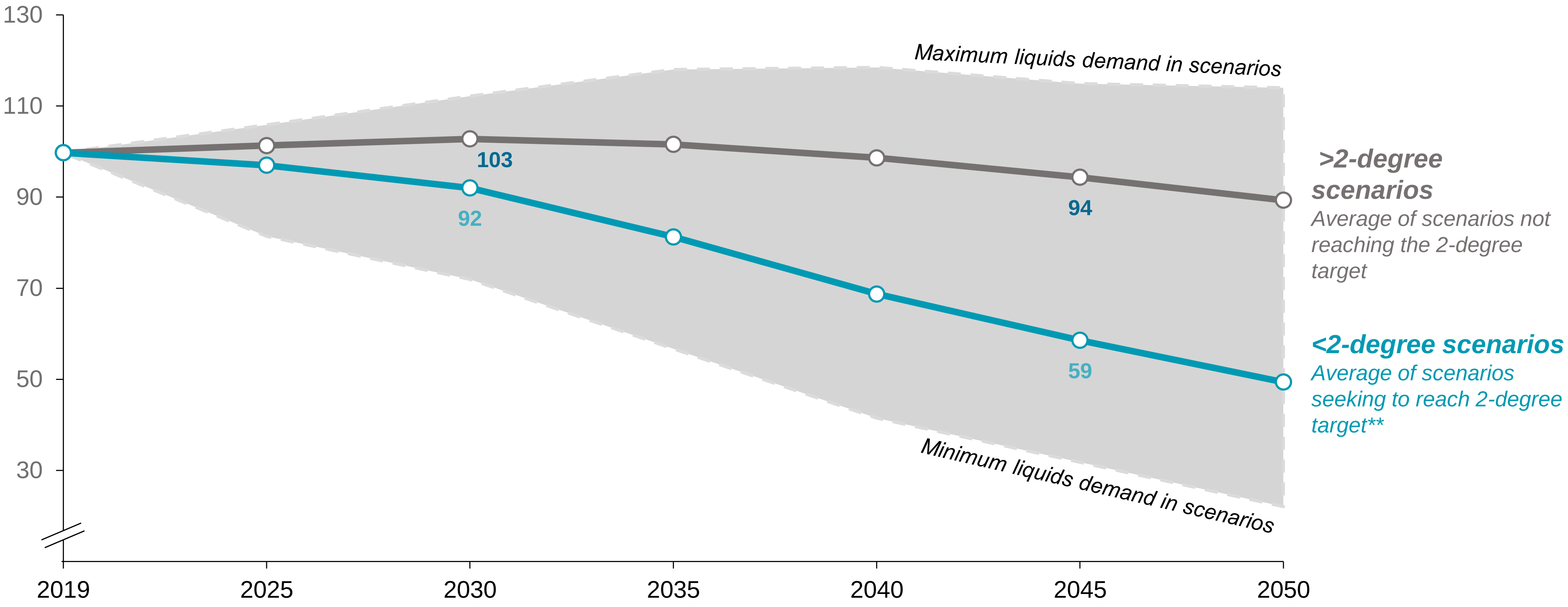


- The projections for the demand of petroleum liquids vary significantly.
- The liquids demand projections mainly separate into two pathways:
  Scenarios not aiming to reach the 2-degree target, and scenarios that aims to reach this target. The scenarios in the first category has a quite stable forecast, while the scenarios that aims to reach the target projects a steep decline in liquids demand.
- Falling liquids demand imply rapid electrification or efficiency gains in the oil-reliant transport sector, which in turn is dependent on technological development and/or large infrastructure investments.

* Indexed to IEA 2019 levels as different providers define units and markets differently EIA not included as they don't have any updated post-COVID scenario, making it less relevant and comparable.
Source: Rystad Energy research and analysis; IEA WEO 2020; Shell Scenarios 2020; OPEC WOO 2020; BP EO 2020; EIA International Energy Outlook 2020; Equinor Energy Perspectives 2020; DNV GL ETO 2020

Averages of scenarios dependent on their climate ambitions yield two distinct demand cases

Global liquids demand in different scenarios*
Million boe/d

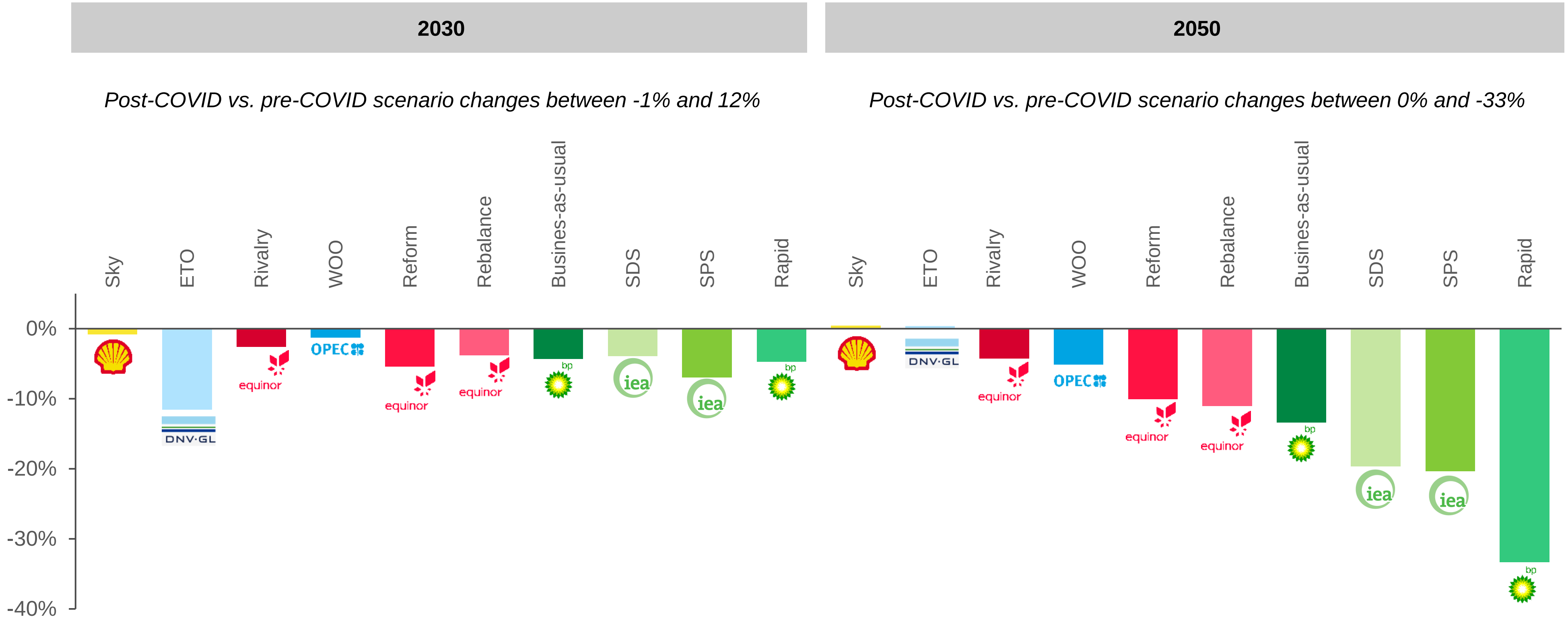


- We construct two scenarios for future liquids demand. One high case with the scenarios that don't reach the >2-degree target and one low case with the scenarios that aim to reach the 2-degree target.
- These cases are used in our assessment of new technologies' potential impact on NCS competitiveness.
- As different supply sources of petroleum liquids have different characteristics and compete against each other for market share, the two cases allow us to assess which NCS volumes can be expected in the supply mix both in a continued high demand-environment and in a world where the sustainable development targets are reached.

* Indexed to IEA 2019 levels as different providers define units and markets differently. EIA not included as they don't have any updated post-COVID scenario, making it less relevant and comparable. **Ex. IEA Net Zero Source: Rystad Energy research and analysis

Post COVID-19 scenarios project a faster decline in liquids demand

Percentage change in projected liquids demand, post-COVID relative to pre-COVID*
% change by scenario and year



Post-COVID vs. pre-COVID scenario changes between -1% and 12%

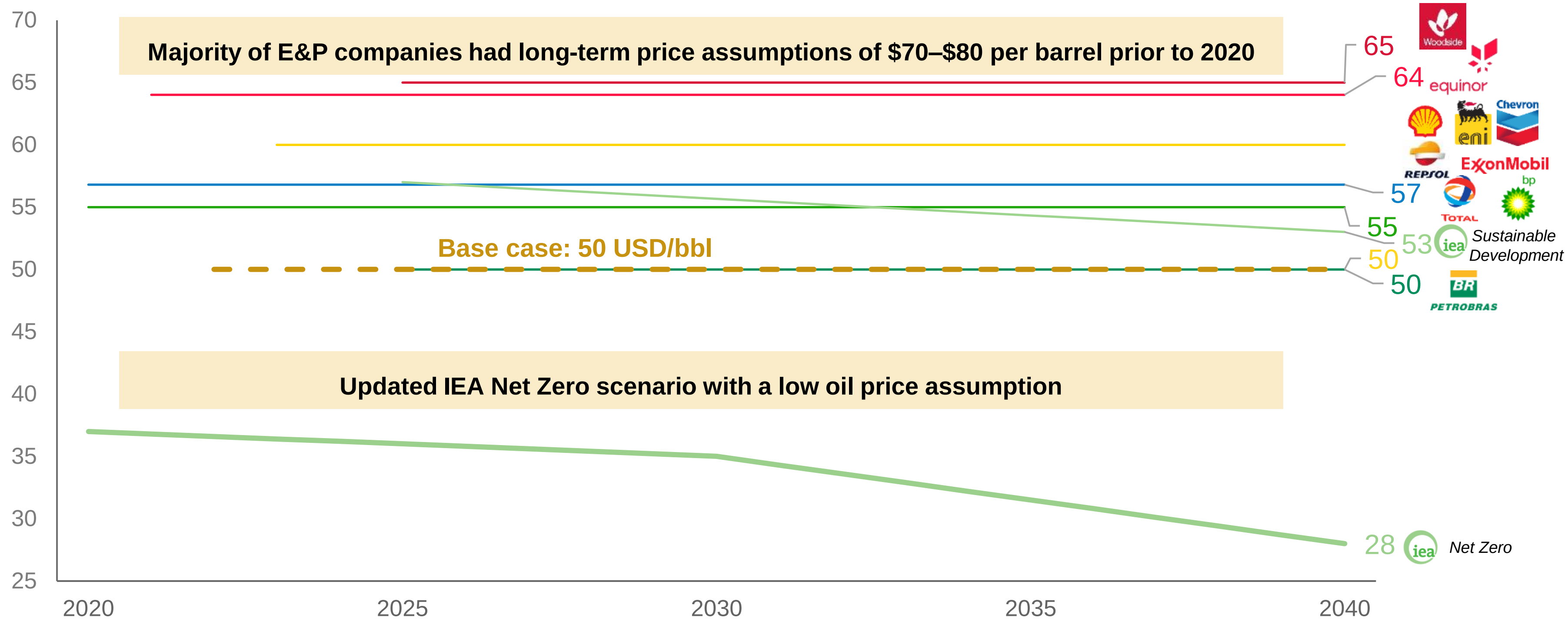
Post-COVID vs. pre-COVID scenario changes between 0% and -33%

- The COVID-19 pandemic has accelerated scenario providers view on the pace of the energy transition. Their post-COVID scenarios foresees a steeper decline in liquids demand relative to their pre-COVID scenarios.
- BPs rapid scenario is the scenario with the largest post-COVID change, foreseeing a liquids demand in 2050 that is ~30% lower than the pre-COVID scenario.
- The focus on the energy transition has also gained increased traction in recent years, further affecting the scenario providers view on future oil demand.
- The difference between scenario vintages are largest in the long-term with less short-term differences.

* Scenario definitions/labeling has also changed somewhat in some instances, not making them exactly 1:1 comparable. IEA NET Zero scenario is new and not included
Source: Rystad Energy research and analysis; IEA WEO; Shell Scenarios; OPEC WOO; BP EO; EIA International Energy Outlook; Equinor Energy Perspectives; DNV GL ETO

Long-term oil price assumptions among E&Ps vary within a band of 50-65 USD/bbl

Long-term Brent crude oil price assumptions
USD per barrel



Majority of E&P companies had long-term price assumptions of $70–$80 per barrel prior to 2020

Base case: 50 USD/bbl

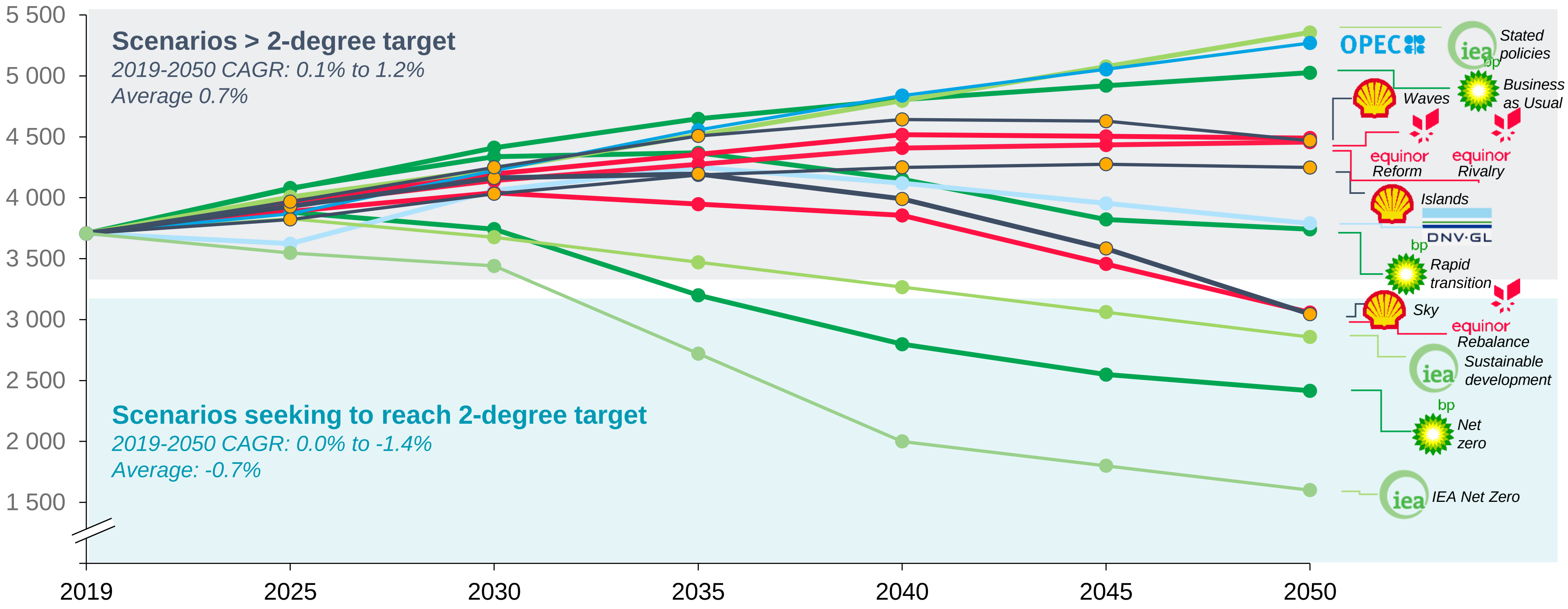
Updated IEA Net Zero scenario with a low oil price assumption

- The figure shows the long-term price assumptions of various E&P companies as references in their annual reports for 2020, as well as IEAs SDS and Net Zero oil price scenarios. Long-term is generally used to refer to the time period up to 2050.
- In the wake of COVID-19, E&P companies have revised down their long-term oil price assumptions, with most falling between 50-65 USD per barrel.
- 2020 assumptions represent a marked reduction from the 70-80 USD per barrel that was the typical long-term price assumption references by E&P companies previously.
- IEAs latest Net Zero scenario is the scenario that foresees the lowest oil price, with a price of 28 USD per barrel in 2040.

*Interpolated between stated years **States European price and not specifically NBP Source: IEA WEO 2020, Equinor annual report 2020; Rystad Energy research and analysis

Although varied, the projections for global gas demand are more positive than for oil

Global gas demand in different scenarios*
Billion cubic meters/year

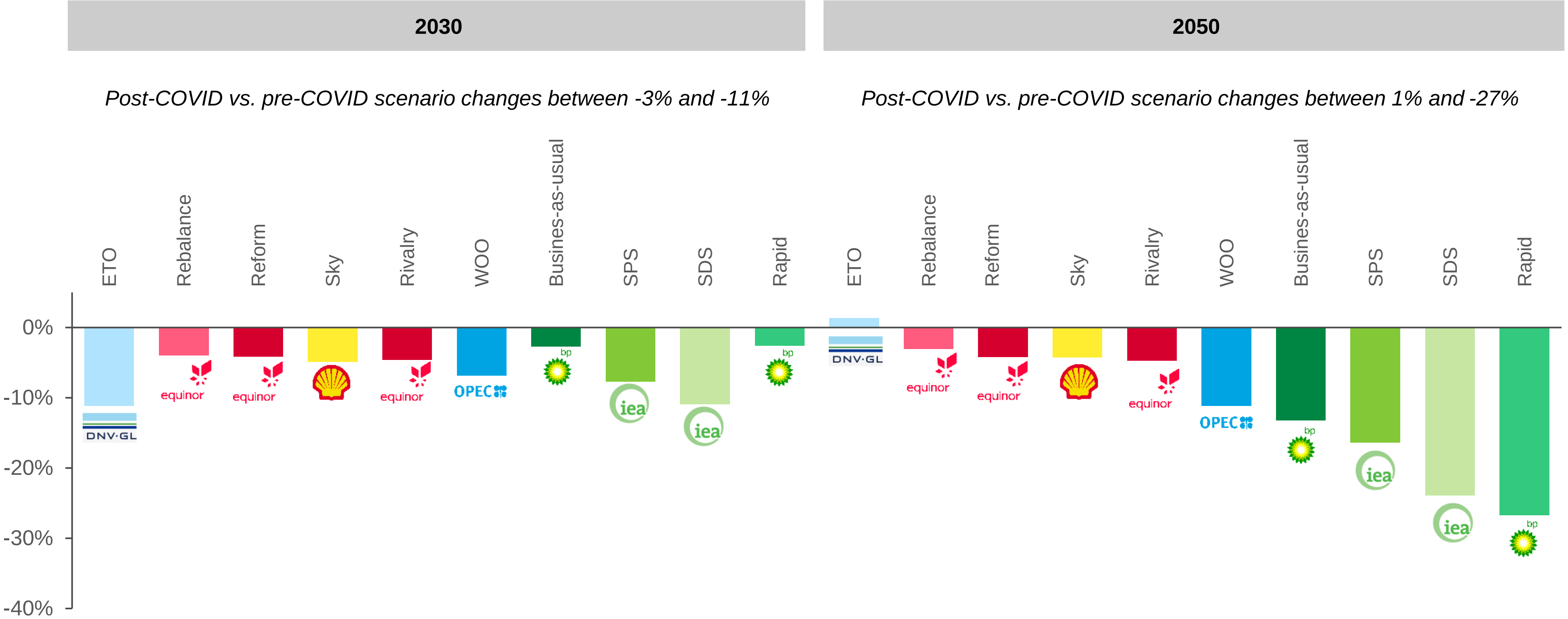


- As with liquids, the global demand for gas vary substantially among the scenarios in the long term.
- The low carbon scenarios from Equinor and Shell assume lower gas demand in 2050 compared to 2019.
- Gas demand is projected at the same levels as today in DNV GL’s scenario, despite the high degree of electrification assumed in the scenario.
- Several scenarios display increasing gas demand, compared with liquids that have flat projections at best. This indicates that gas is the preferred source of energy of the two.
- All scenarios seeking to reach the 2-degree target foresees a decline in gas demand, and the scenarios are distinctly separated from the scenarios not aiming to reach this target.

* Indexed to RE 2019 levels as different providers define units and markets differently
Source: Rystad Energy research and analysis; IEA WEO 2020; Shell Scenarios 2020; OPEC WOO 2020; BP EO 2020; EIA International Energy Outlook 2020; Equinor Energy Perspectives 2020; DNV GL ETO 2020

Expected gas demand also revised significantly down in post-COVID scenarios

Percentage change in projected gas demand, post-COVID relative to pre-COVID*
% change by scenario and year

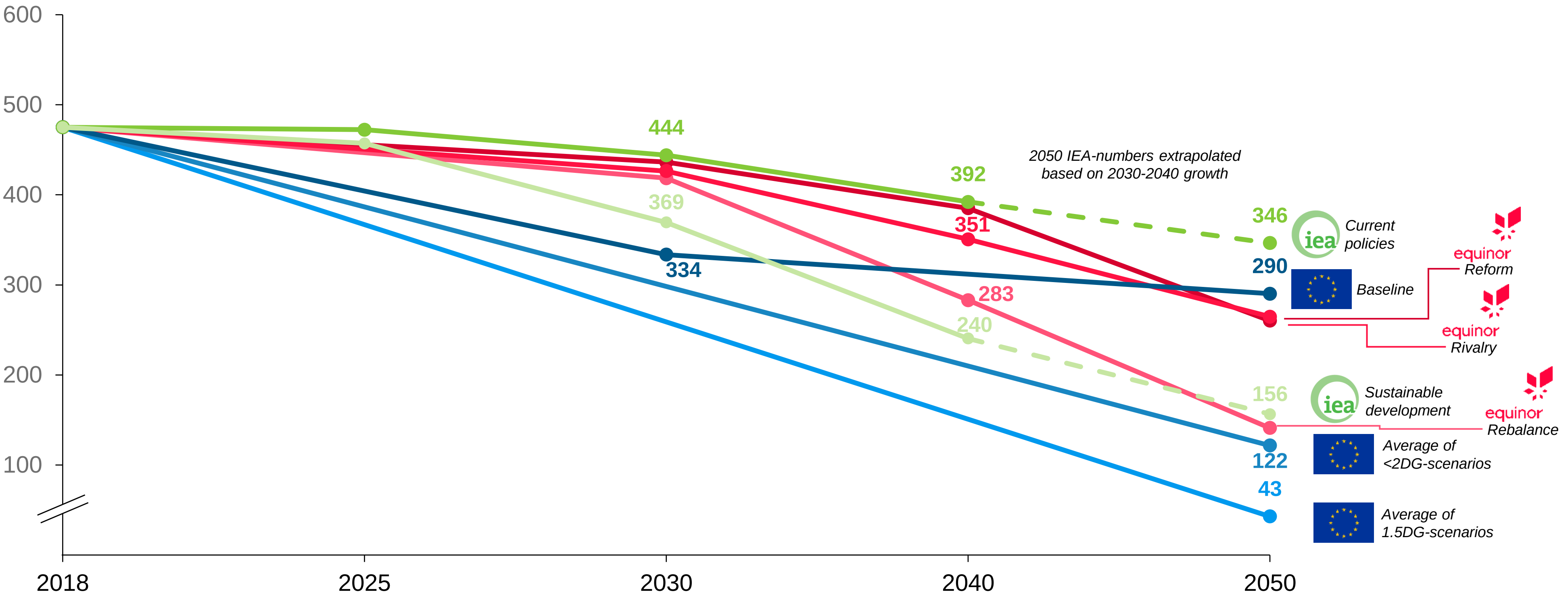


- The COVID-19 pandemic and the increased focus on the energy transition has led to a decrease in projected gas demand in the different scenarios, in the same way as it has affected liquids demand.
- The gas revisions are quite aligned with the liquids demand revisions, highlighting that there is a general shift towards projecting less oil and gas in the total energy mix.
- As was the gas for oil demand, the differences is largest in the long term, with BPs rapid scenario being the scenario that is revised down the most.

* IEA NET Zero scenario is new and not included
Source: Rystad Energy research and analysis; IEA WEO 2020; Shell Scenarios 2020; OPEC WOO 2020; BP EO 2020; EIA International Energy Outlook 2020; Equinor Energy Perspectives 2020; DNV GL ETO 2020

EU’s vision for sustainable development leaves less room for gas in EU28s energy mix

EU28 gas demand in different scenarios
Billion cubic meters/year

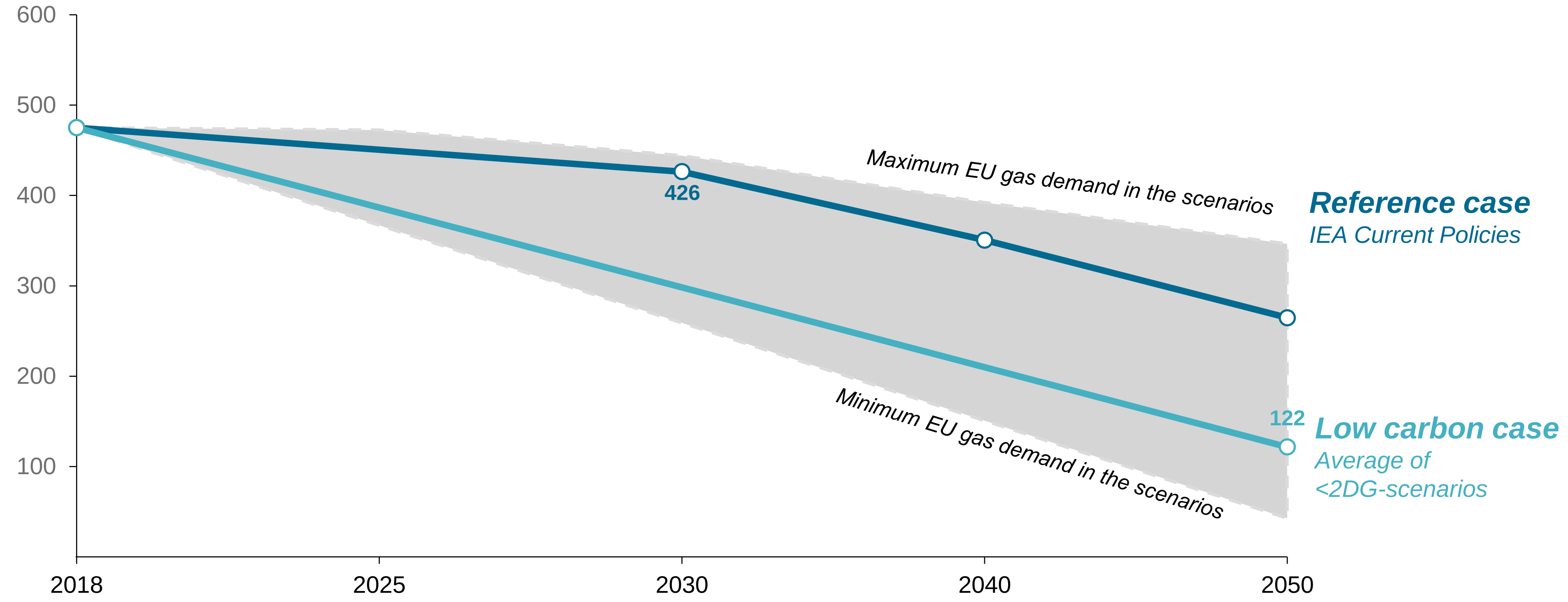


- The European Commission issued back in November 2018 a report dubbed “A Clean Planet for All”. This report contains *“A European strategic long-term vision for a prosperous , modern, competitive and climate neutral economy”.* The report is written to *“… confirm Europe’s commitment to lead in global climate action”*, and should as such be read as a guiding document for European policymakers. This report still forms the basis for Europe’s long-term strategy.
- The chart outlines a strategy that is compliant with the Paris Agreement. EUs <2-degrees projections are quite aligned with Equinor and IEAs <2-degrees scenarios.
- All scenarios foresee a decline in European gas demand. This is particularly prevailing in the low carbon scenarios.

*Indexed to IEA EU28 gas demand as definitions vary across scenarios. Source: Rystad Energy research and analysis; IEA WEO 2020; EU Commission; Equinor Energy Perspectives 2020

Both gas cases project reduction in EU gas demand

EU28 demand in different scenarios
Billion cubic meters/year

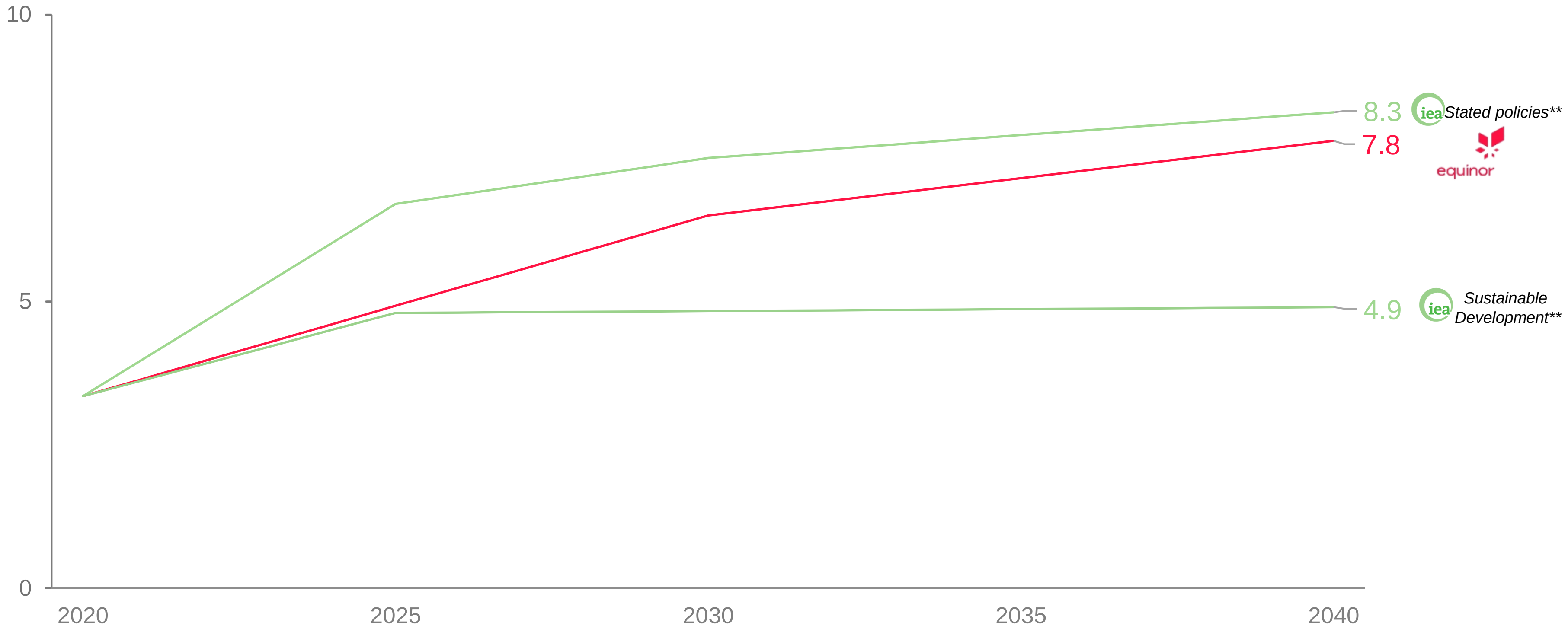


- In order to sensitize our assessment of new technologies' potential impact on NCS competitiveness to EU policy we use the average of <2DG-scenarios as outlined in the "Clean Planet for all"-report issued by the European Commission as our low carbon case
- The well known Current Policy-scenario issued by the IEA is used as our reference case
- The reference and low carbon cases project a reduction in EU 2050 gas demand compared with 2017
- IEA Current Policies assume only marginal increase in EU gas demand
- The scenarios indicate that Norwegian gas supply lacks exposure to a potential increase in global gas demand as most of Norwegian gas is piped to EU countries

Source: Rystad Energy research and analysis; IEA WEO 2018; EU Commission

Gas prices expected to increase and stabilize at 7-8 USD/MMBtu

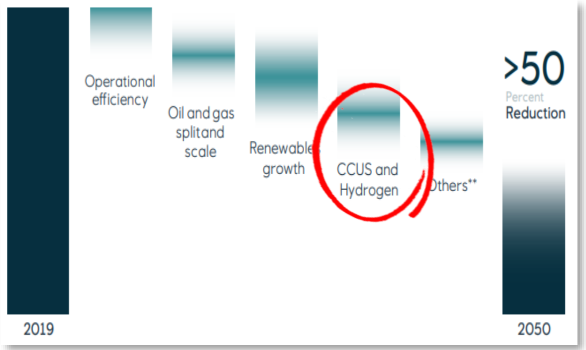
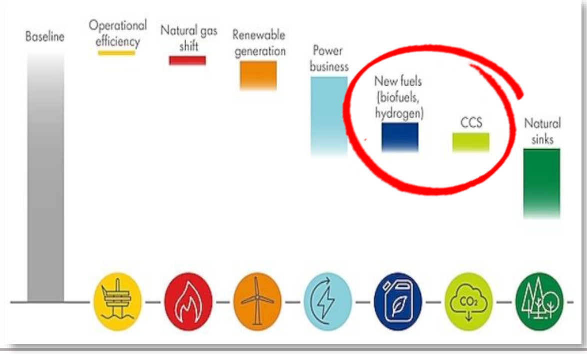
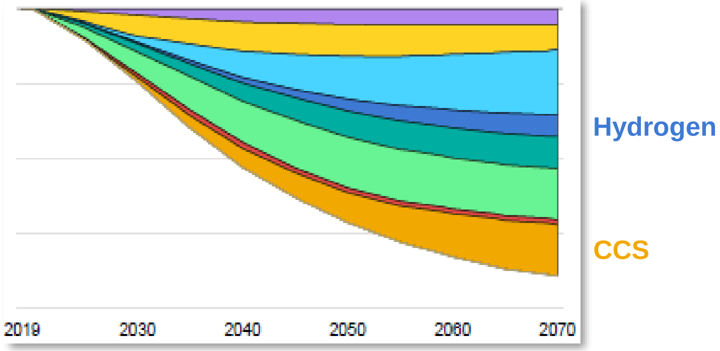
Long-term NBP (National Balancing Point) gas price assumptions*
USD/MMBtu REAL



- Gas prices are by nature volatile, and different stakeholders expect volatility going forward, but where the trend is a gradual increase in prices.
- As Equinor states in their 2030 annual report from 2030, it is expected prices at levels sufficient to incentivize the next LNG investment cycle, resulting in a flatter price curve.

*Interpolated between stated years **States European price and not specifically NBP Source: IEA WEO 2020, Equinor annual report 2020; Rystad Energy research and analysis

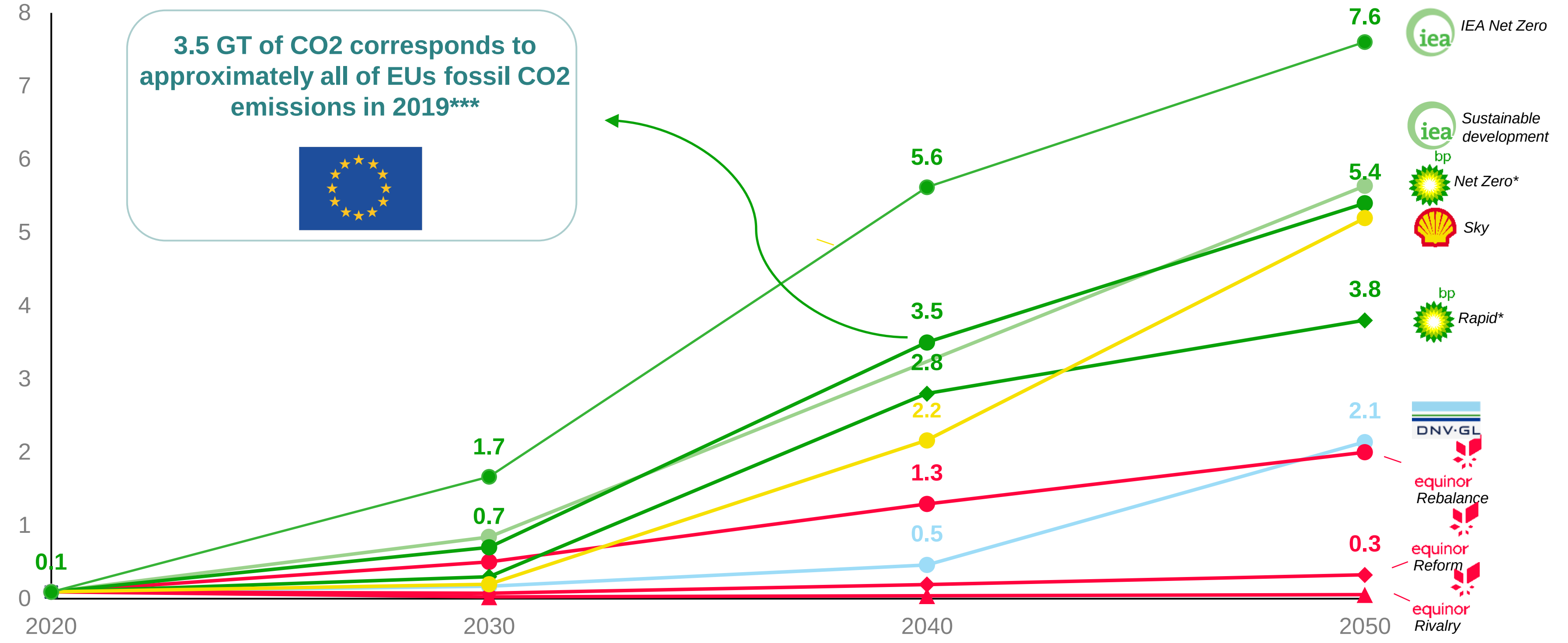
CCUS and Hydrogen viewed as important measures in order to reduce emissions

Organization	Facsimiles; roadmaps to emission reductions	Comment
equinor		• Equinor aim to reduce net carbon intensity by at least 50% by 2050. • The net carbon intensity approach takes into account emissions from initial production to final consumption relative to total energy delivered. • The facsimile to the left is from Equinor's 2020 climate roadmap, highlighting how they foresee reaching this target. • CCUS and Hydrogen is highlighted as important measures.
		• Shell's long-term target is to become a net-zero emissions energy business by 2050. The facsimile to the left highlights some of the key measures they foresee to utilize to reach this target. • As Equinor, Shell also highlights Hydrogen and CCS as important measures in order to reduce emission intensity. Shell also view natural sinks as important. This include measures such as reforestation.
iea		• The facsimile to the left is from IEAs special report on CCUS, released in 2020. It displays global energy sector CO2 emissions reductions by measure in the Sustainable Development Scenario relative to the Stated Policies Scenario. • The chart highlights how hydrogen (dark blue) and CCS (orange) is viewed as important for reaching the climate ambitions.

Source: Equinor Climate Roadmap 2020; Shell; IEA CCUS in clean energy transition; Rystad Energy research and analysis

Several scenarios' project significant long-term use of CCS

Global CO2 capture**
GT CO2/year



3.5 GT of CO2 corresponds to approximately all of EUs fossil CO2 emissions in 2019***

- Several scenarios' project significant long-term use of CCUS.
- The scenarios are quite widespread, and not all scenarios have quantified targets for CCS use.
- Among the scenarios aiming to reach the 2-degree target, all scenarios view CCUS as an important measure, with IEA and BP estimating ~5.5 GT of CO2 captured annually.
- In 2040, BPs net zero scenario projects an annual CO2 capture of 3.5GT. This corresponds to approximately all of EUs emissions*** in 2019, highlighting that CCS is projected to be quite impactful in reaching the climate targets.
- IEAs Net Zero scenario is the most ambitious with regards to CO2 capture – projecting a capture of 7.6 Gt in 2050

*Scenario difference relative to "business-as-usual", where it is assumed that "business-as-usual" is close to zero. Emissions from energy use. **Likely varies to which extent direct air capture (DAC) is taken into account. However, DAC constitutes only a minor part in scenarios where it is explicitly stated. ***EU27 + UK Source: EDGAR; Rystad Energy research and analysis

The price of the CO2 quotas in EU-ETS has surged in recent years

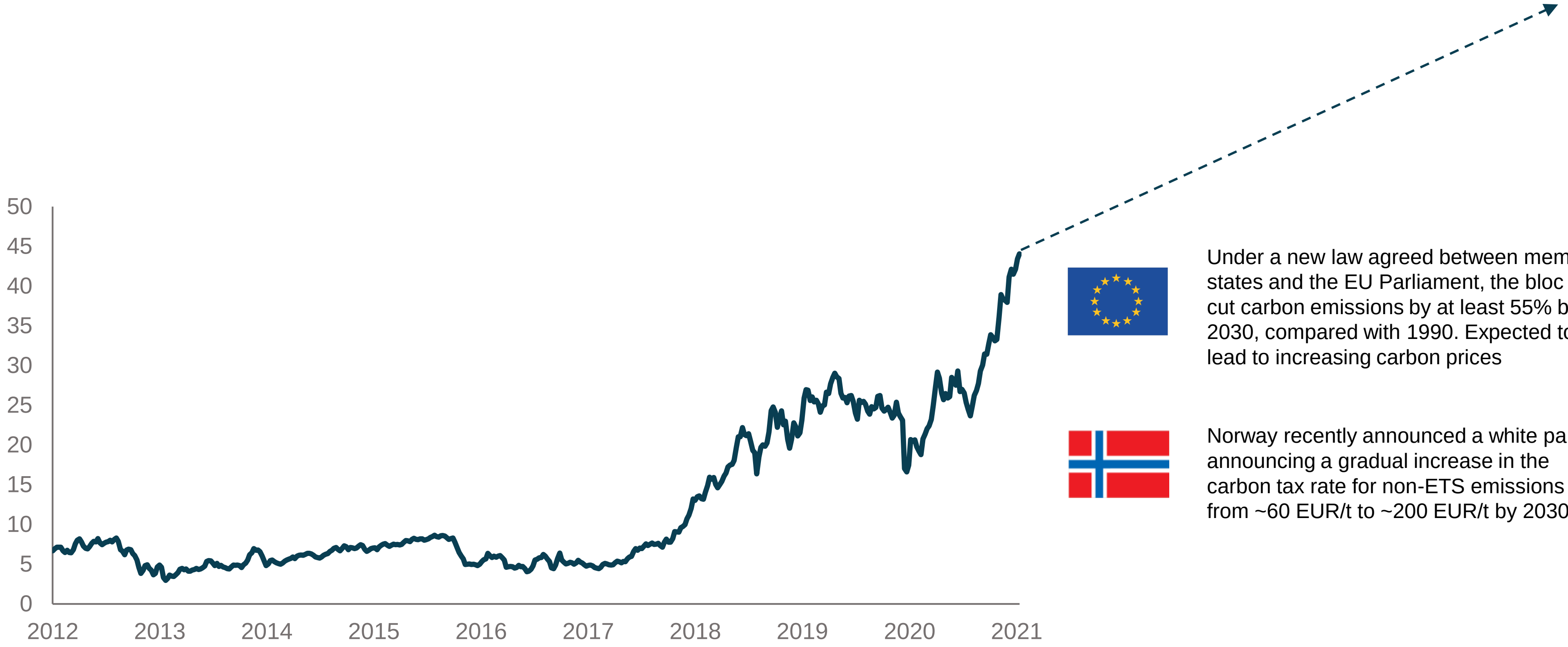
EU-ETS CO2 quota price
Euros per tonne

- The price of CO2 quotas has surged in recent years.
- The price surge could be explained by the rapidly increasing focus on energy transition in recent years. It is also a result of stronger regulations in the EU. Under a new law agreed between member states and the EU Parliament, the bloc will cut carbon emissions by at least 55% by 2030 relative to 1990(compared to the current target being 40%).
- Increased ambitions and tighter supply could continue to drive the prices. Several stakeholders are expecting the long-term carbon prices to continue to increase.

Source: Rystad Energy research and analysis

Price on emitting expected to continue to increase going forward

EU-ETS CO2 quota price
Euros per tonne



Under a new law agreed between member states and the EU Parliament, the bloc will cut carbon emissions by at least 55% by 2030, compared with 1990. Expected to lead to increasing carbon prices

Norway recently announced a white paper announcing a gradual increase in the carbon tax rate for non-ETS emissions from ~60 EUR/t to ~200 EUR/t by 2030

- The price of CO2 quotas has surged in recent years.
- Under a new law agreed between member states and the EU Parliament, the bloc will cut carbon emissions by at least 55% by 2030 relative to 1990 (compared to the current target being 40%).
- One of their key measures to reaching this target is the EU-ETS system. The system has a cap set on the total amount of CO2 that can be emitted each year, and this cap is reduced over time. A reduced number of total allowances is expected to continue to push prices upwards.
- Emissions not covered by the EU-ETS system is also expected to increase, with Norway announcing a planned increase in carbon tax rate from ~60 EUR/t to ~200 EUR/t by 2030.

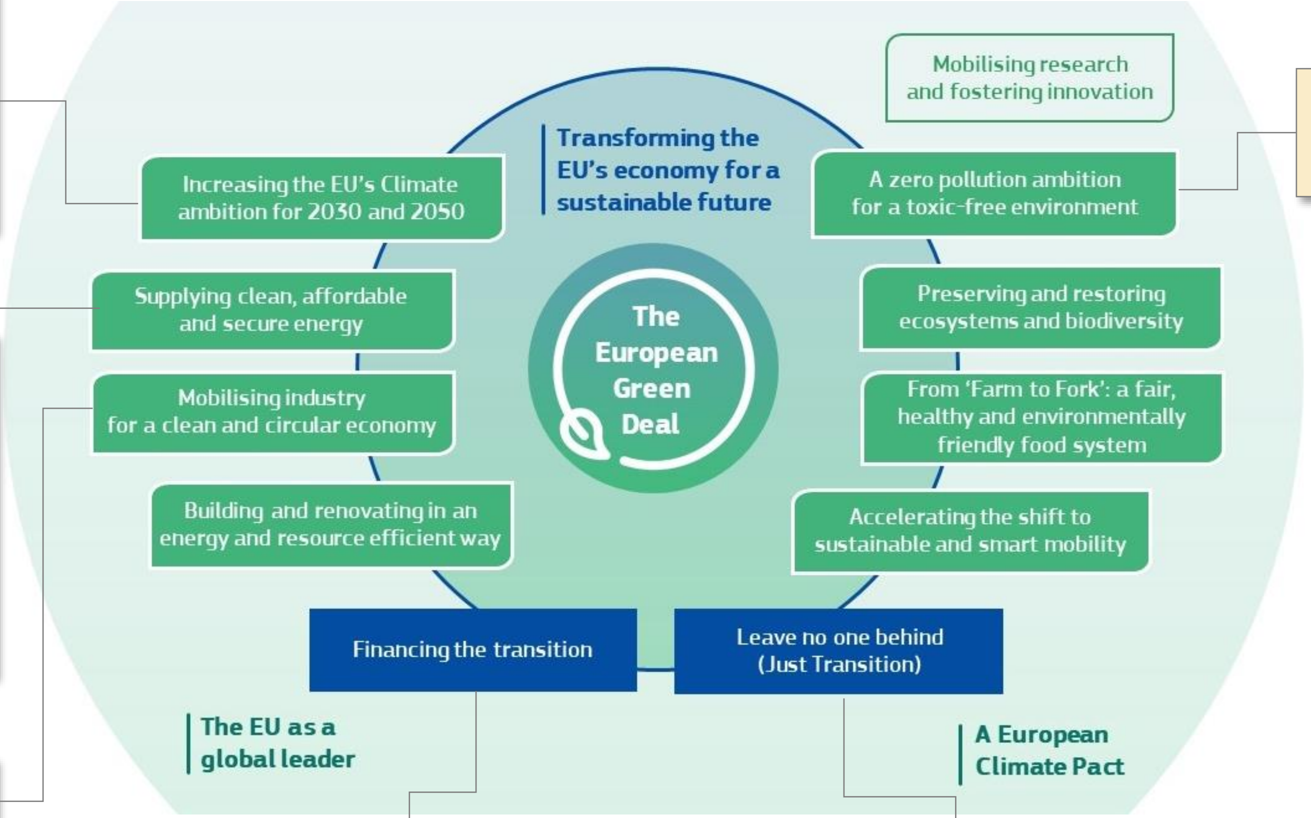
Source: Regjeringen.no; Rystad Energy research and analysis

The European Green Deal is the largest industry project in EUs history

- **Revision of 2030 targets**
- *Revision and extension of ETS*
- *Carbon border adjustment Mechanism*

- **Hydrogen strategy**
- **Energy Systems strategy**
- **Offshore Renewable Energy strategy**
- *European framework for gas*
- *Review of energy taxation directive*

- *Circular economy action plan*



- **Strategy on sustainable use of chemicals**
- *Revision of the Industrial Emissions Directive*

- **European Green Deal Investment Plan**
- **Green taxonomy**
- *Revision of state aid for environmental protection and energy*
- *Revision of the Communication on IPCEIs*

Just Transition Fund

Implemented actions

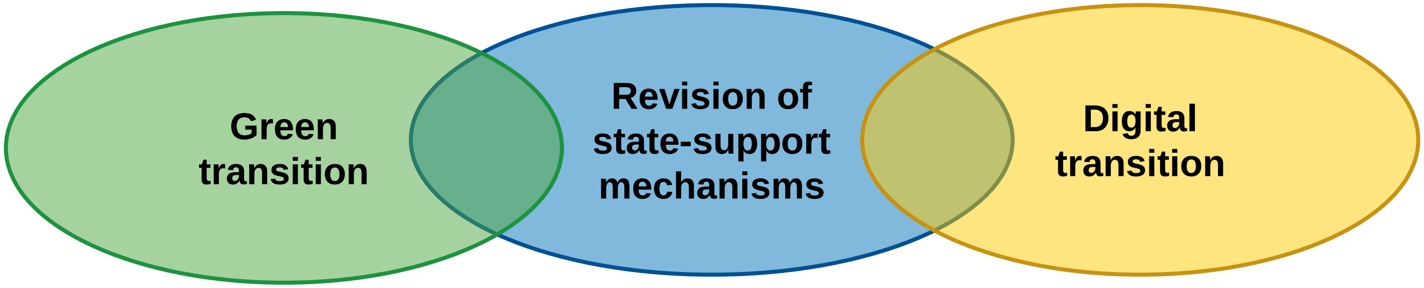
Expected actions

Source: European Commission

EGD is also a quest for strategic autonomy through digital and green transition

The quest for strategic autonomy

Following COVID-19 and prior geopolitical vulnerability exposures, EU political leadership have placed increased importance on the concept of strategic autonomy where both the green and digital transition are viewed as key levers. European strategic autonomy is about making Europe less dependent of other countries within most industry areas and ensure that their industry is competitive outside the European Union (European Champions). This policy shift has been met with critique from Nordic and Baltic countries that with their small and open economies are dependent on working under WTO trade regulations.



Important Projects of Strategic European Interest (IPCEIs)

December 2018

IPCEI on microelectronics

1.75 billion Euro

Commission approves plan by France, Germany, Italy and the UK to give €1.75 billion public support to joint research and innovation project in microelectronics. Austria joined in 2091. A second IPCEI in microelectronics are calling for expression of interest

December 2019:

IPCEI on battery value chain

3.2 billion Euro

Commission approves €3.2 billion public support by seven Member States for a pan-European research and innovation project in all segments of the battery value chain

January 2021:

IPCEI on battery value chain

2.9 billion Euro

The European Commission approved today €2.9 billion public support by twelve Member States for a second Important Project of Common European Interest (IPCEI) to support research and innovation in all segments of the battery value chain

Soon

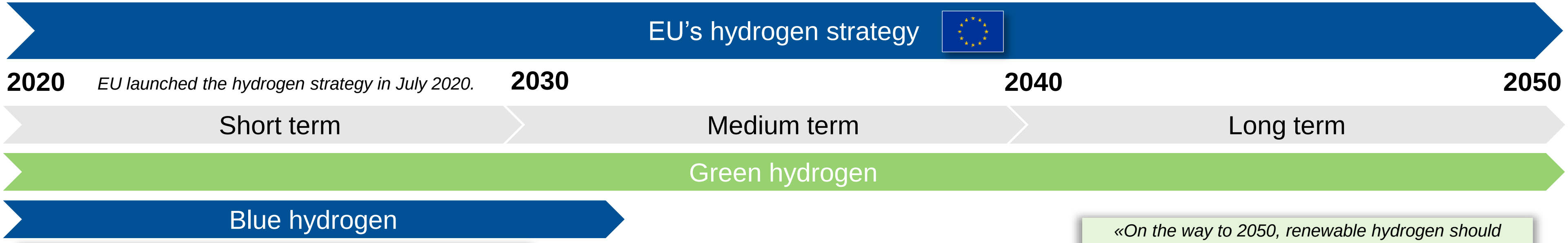
IPCEI on Hydrogen

XX billion Euro

Twenty-two EU member states and Norway have signed a declaration of intent stating their willingness to support the development of a European value chain for green hydrogen in particular and to invest billions of euros accordingly.

Source: Rystad Energy research and analysis

Hydrogen is seen as more than a transition fuel and is consequently favored by the EU



EU launched the hydrogen strategy in July 2020.

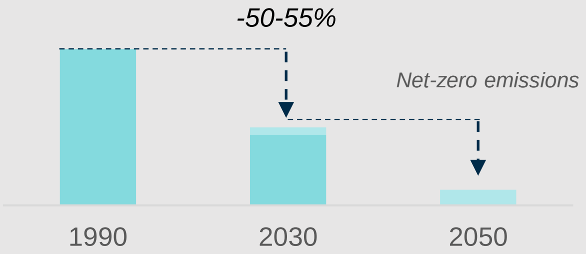
«In the short and medium term, however, other forms of low-carbon hydrogen are needed, primarily to rapidly reduce emissions from existing hydrogen production and support the parallel and future uptake of renewable hydrogen.»

«On the way to 2050, renewable hydrogen should progressively be deployed at large scale alongside the roll-out of new renewable power generation, as technology matures and the costs of its production technologies decrease.»

Goals

Goals for installed electrolysis capacity

EU's new climate goals – reductions in emissions

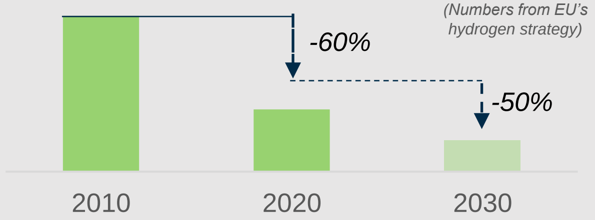


Costs

Estimated costs for EU hydrogen production, 2020

Euro/kg H2

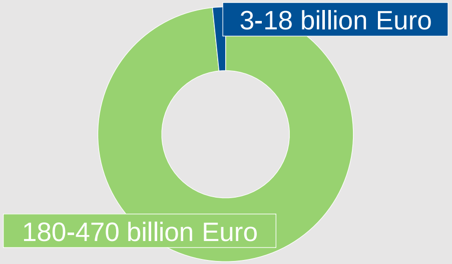
Costs from electrolysis in the EU



(Numbers from EU's hydrogen strategy)

Investments

Estimates for cumulative investments in hydrogen in Europe within 2050



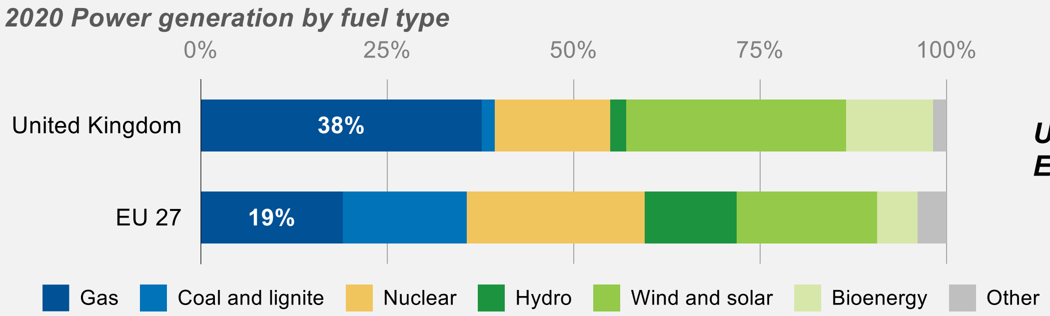
- This means that the EU is looking to invest mainly in development of green hydrogen and electrolysis capacity.
- This basically means that investments within blue hydrogen will be dependent of initiatives from oil companies or others that are willing to invest in gas reformation and carbon capture and storage.

Sources: Rystad Energy research and analysis; European Commission «*A hydrogen strategy for a climate-neutral Europe*»

Impact of Brexit – important voice of Norwegian interest is gone from EU foras

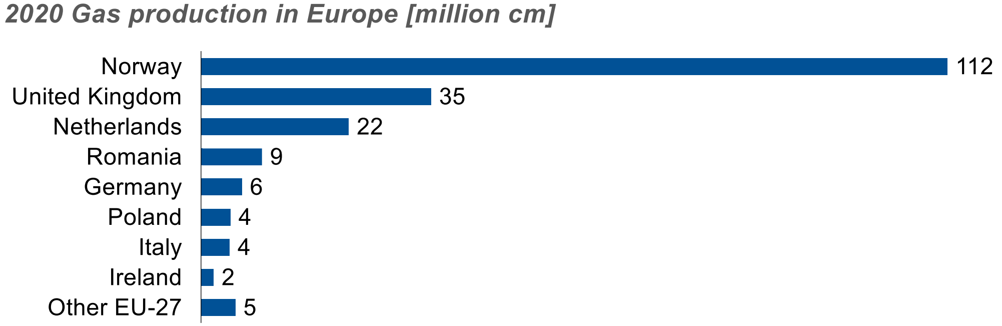
Areas where UKCS voice = NCS voice

Gas for power generation



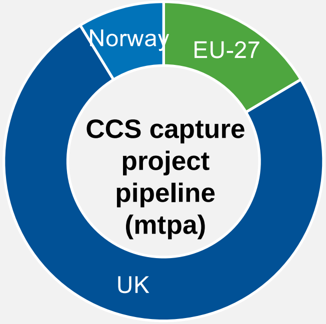
UK is twice as gas dependent as EU27, gas is the main source for UK power generation

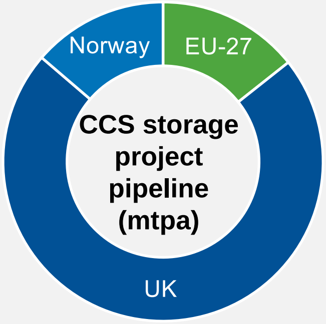
Gas producer



UK is the second largest gas producer in Europe following Norway, limited and fragmented EU production of gas for either conventional or new gas value chains (blue hudrogen/ammonia)

New value chains





UK leading the way on energy value chains of high strategic interest for Norway, EU marginal compared to size

Source: Rystad Energy research and analysis

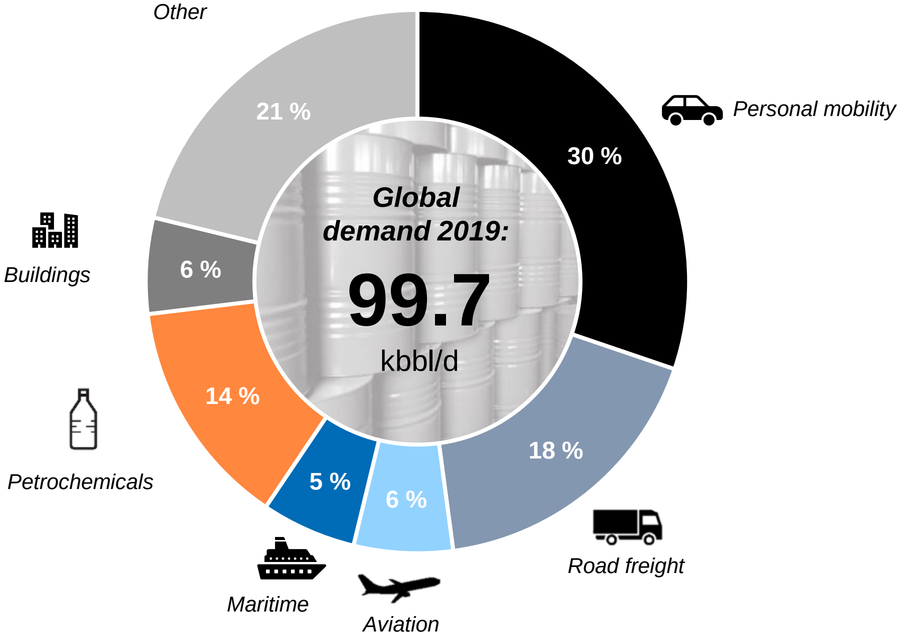
Report contents

Oil is a global market, gas is more localized with Norway mainly exporting to Europe

Oil

Market served:

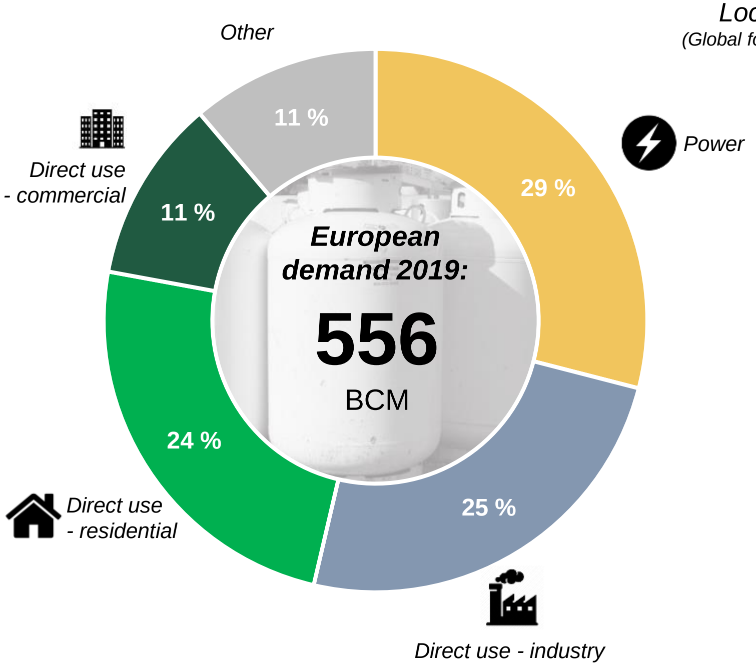
Global



Gas

Market served:

Local
(Global for LNG)



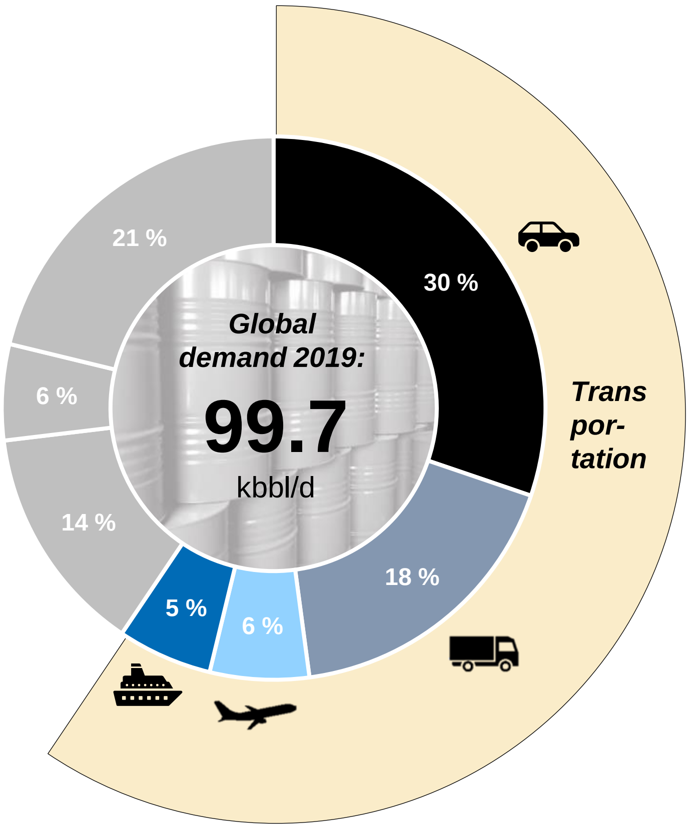
- Global oil demand in the «normal year» of 2019 was at about 100 mbbl/d. 2020 had about 10 mbbl/d less demand on average.
- The transportation sector accounts for about 60% of demand, with road vehicles (cars, busses, semi-trucks etc.) making up the majority of that portion.
- The «Other» portion is largely made up of power generation for either the grid or local consumption, industrial applications and agriculture.

- Gas markets are more localized as gas is not liquid in their natural state and require costly liquefaction to be transported as LNG over larger distances.
- Norwegian gas largely supplies the Northern European market and consequently competes with other suppliers to this region such as Russia and the domestic producers.
- Consumption is largely either for power in the grid (29%), or for direct consumption, for instance including turbines on industrial sites or stoves in households.

Source: Rystad Energy research and analysis; OilMarketCube; GasMarketCube

60% of oil demand related to transportation – heavy and light transp. displaced differently

Oil



Light transportation displacement

Needs moderate energy density

Batteries have cemented their position as the preferred energy storage technology if light transportation mobility is to reduce its carbon footprint. Few car manufacturers are still pursuing hydrogen as a viable alternative, with the Japanese manufacturers being the most adamant until recently.

Personal mobility

Renewables + *Batteries*

Heavy transportation displacement

Needs moderate to high energy density

Hydrogen has higher energy density than what is seen as viable with current generation or even next generation battery technology. Consequently, it is the most suitable alternative for heavier modes of transportation where the needed battery would simply be too large or where battery supply chains cannot deliver the required number of cells. Lighter modes of heavy transport could still use batteries, however.

Road freight

Aviation

Maritime

H_2

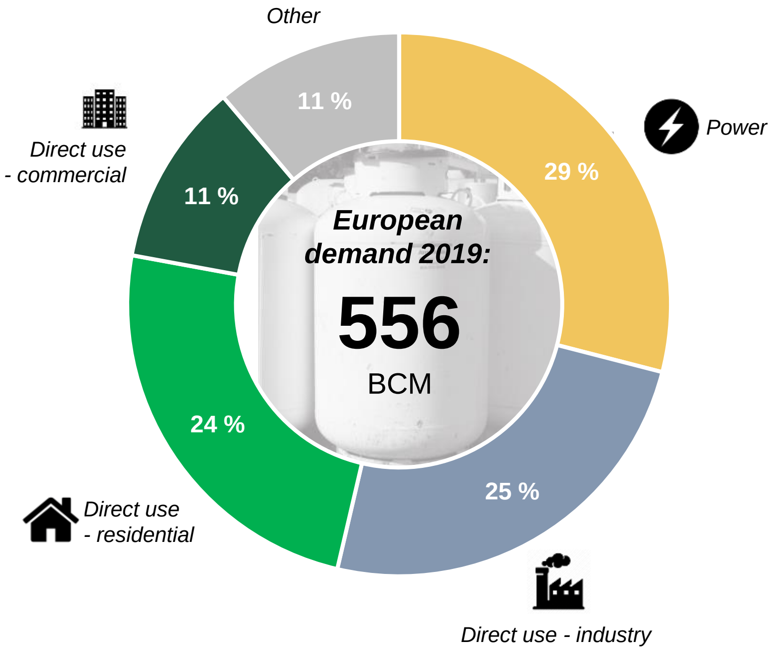
Hydrogen fueling

Batteries

Source: Rystad Energy research and analysis; OilMarketCube

Large rollout of batteries or hydrogen ultimately needed to fully displace European gas demand

Gas



Displacement of gas for power

Displacing gas with renewables has its challenges given the concept of intermittency; wind won't necessarily blow at the exact peaks of power demand that arise during the day. This spurs the need for renewables to be coupled with storage if it is to fully displace fossil or nuclear, both to supplement the grid when renewable power generation is in deficient to demand, and to dispose of the excess energy that is generated otherwise.

Renewables + H_2 *Storage*

Power

Displacement of gas in direct use

Gas in direct use is most viably displaced by energy dense hydrogen, especially for industrial applications. For domestic applications, the route to gas displacement is likely through electrification, upon which power is retrieved from the grid. If that grid power is to be sourced from renewables, this implies the same challenges with intermittency described above.

1. Electrification → *Renewables* + H_2 *Storage*
2. H_2 Direct use hydrogen

Direct use - commercial

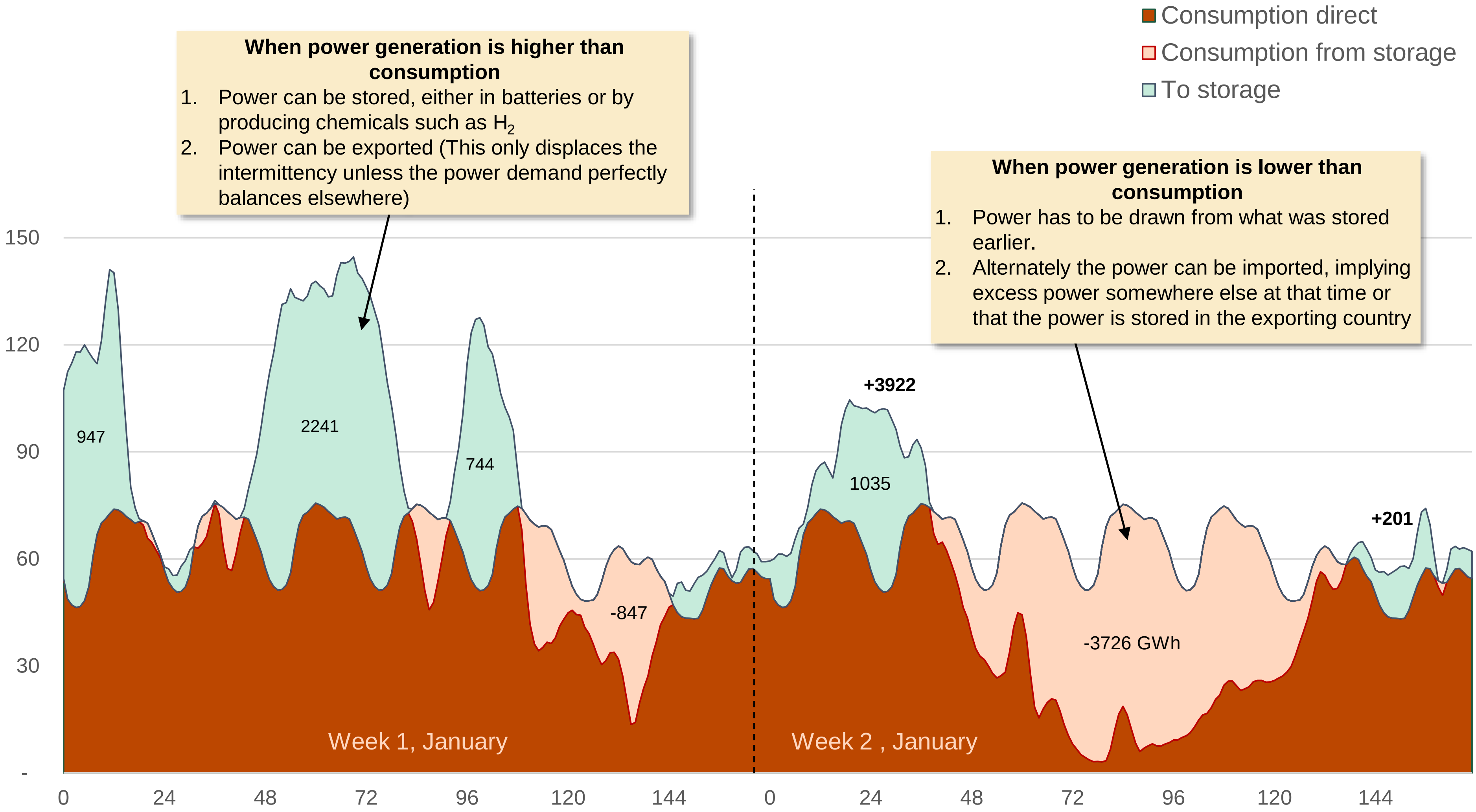
Direct use - residential

Direct use - industry

Source: Rystad Energy research and analysis; GasMarketCube

The concept of intermittency: Germany in 2050 as an example

Power supply and demand in Germany in January 2050 (based on January 2019, but scaled up to 100% renewable mix)
GW



When power generation is higher than consumption

1. Power can be stored, either in batteries or by producing chemicals such as H_2
2. Power can be exported (This only displaces the intermittency unless the power demand perfectly balances elsewhere)

When power generation is lower than consumption

1. Power has to be drawn from what was stored earlier.
2. Alternately the power can be imported, implying excess power somewhere else at that time or that the power is stored in the exporting country

Source: Rystad Energy research and analysis

There are both opportunities and threats associated with the technologies displacing fossil

Large scale displacement of oil and gas broadly relies on two ingredients:
Renewable power generation and **storage opportunities**

Power generation

Renewable power sources

- Solar PV and wind energy are seen as the most likely candidates for a large scale renewables rollout.
- Both technologies have seen tremendous decreases in full lifecycle costs in the last decade: Solar PV by **82%**, onshore wind by **38%** and offshore wind by **29%** (2010 to 2019)

Strengths	Weaknesses
• Very **positive trend on cost** of new capacity • Competitive pricing against fossil and nuclear • Easy access to capital; subsidies or other	• **Relies on storage** to handle the issue of intermittency; short term discrepancies between supply and demand

+

Storage / carriers

Batteries

- Seeing an exponential growth in demand from electric vehicles.
- Is like renewable power sources seeing great improvements in cost, among other reasons from scale benefits.
- Raw materials like cobalt and lithium with supply uncertainty going forward, along with plant capacity to manufacture battery cells

Strengths	Weaknesses
• Technology largely more **mature and scaled** compared to hydrogen.	• Limits on achievable **energy density** • Short term **squeeze in supply chains**; both for the batteries themselves and the materials they are composed of

OR

Hydrogen

H_2

- Three main varieties exist: Green, Blue and Gray. The two former, green and blue, are the low carbon footprint alternatives.
- Green hydrogen relies on power intensive and costly electrolysis.
- Blue hydrogen relies on processing natural gas and handling the CO2 emissions through CCS.

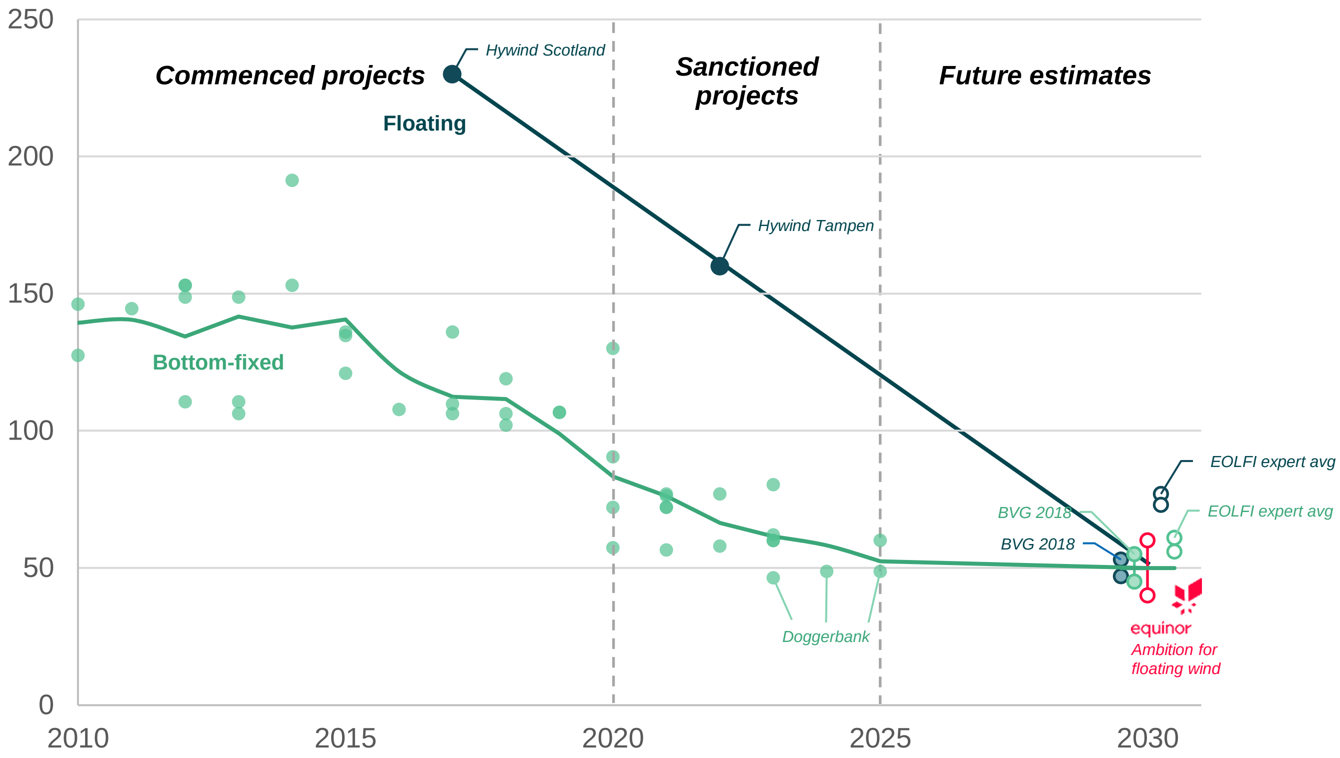
Strengths	Weaknesses
• High energy density • **Abundance of raw materials (**natural gas in blue or water for green)	• Necessary technology immature and expensive • Issue related to transportation due to corrosive properties (must likely be converted to ammonia)

Source: Rystad Energy research and analysis;

Offshore wind with impressive cost reductions, albeit with floating wind lagging behind

Cost development of European offshore wind farms* from 2010 to 2030

Levelized cost of energy (LCOE) by start-up year (EUR/MWh)



The Levelized Cost of Energy (LCOE) for European offshore wind farms has declined steadily since 2015. There are three main elements behind this development:

- Larger park sizes
- Larger turbines
- Competitive auctions (introduced from 2015)

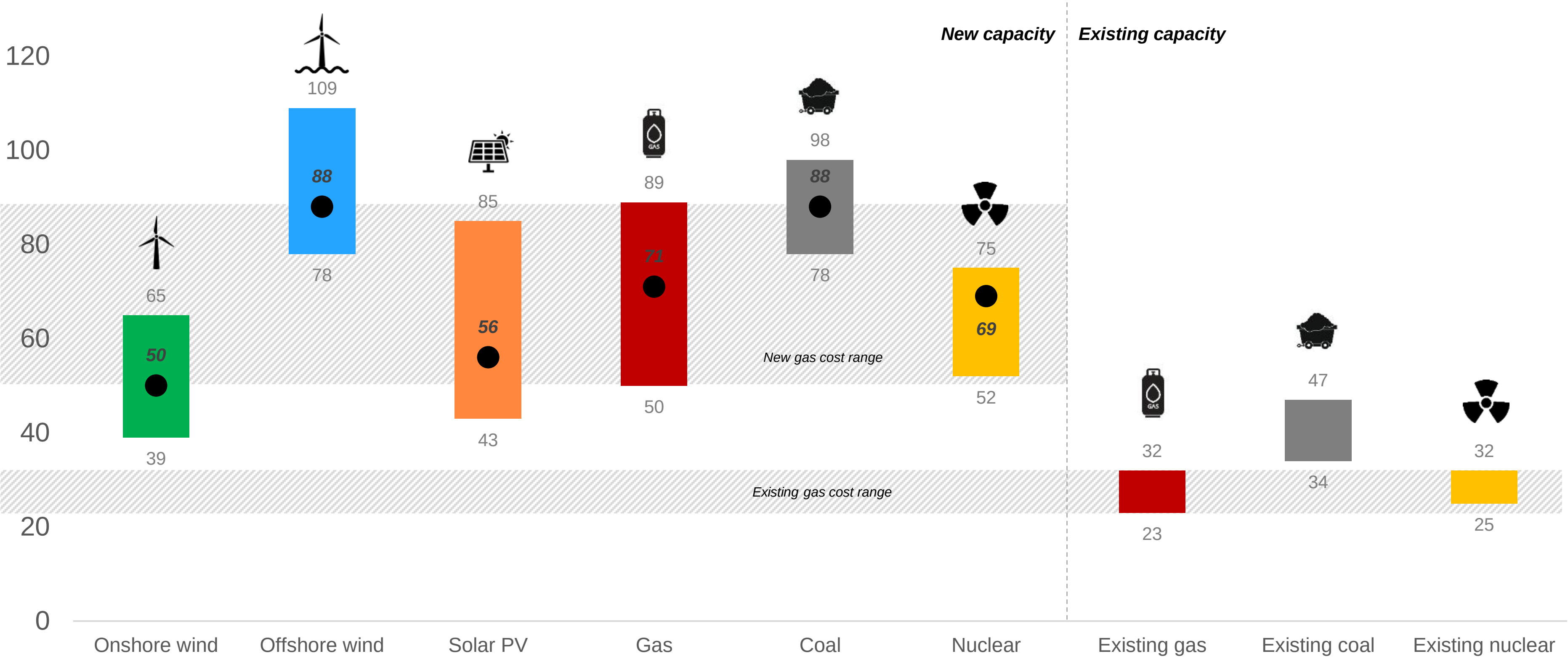
As floating wind matures and larger parks are developed, it is expected by most analysts that the cost of floating and bottom fixed wind will converge to a level of 40-70 EUR/MWh in 2030.

To deliver on these estimates larger parks must be built to enable industrialization, larger turbines and higher capacity factors than for bottom-fixed.

*Selected projects only. Data points from stated LCOE with transmission, strike prices or calculated based on 20440 investment cost with a WACC of 8%. Includes transmission to shore.
Source: Rystad Energy research and analysis; IEA 2019; IRENA 2018; Equinor; BVG Associates 2018; EOLFI 2018; Catapult; Carbonbrief

Renewable power costs very competitive vs. new fossil, but not yet with existing

Global LCOE levels for various power sources (5th percentile, 95th percentile and median)
USD/MWh



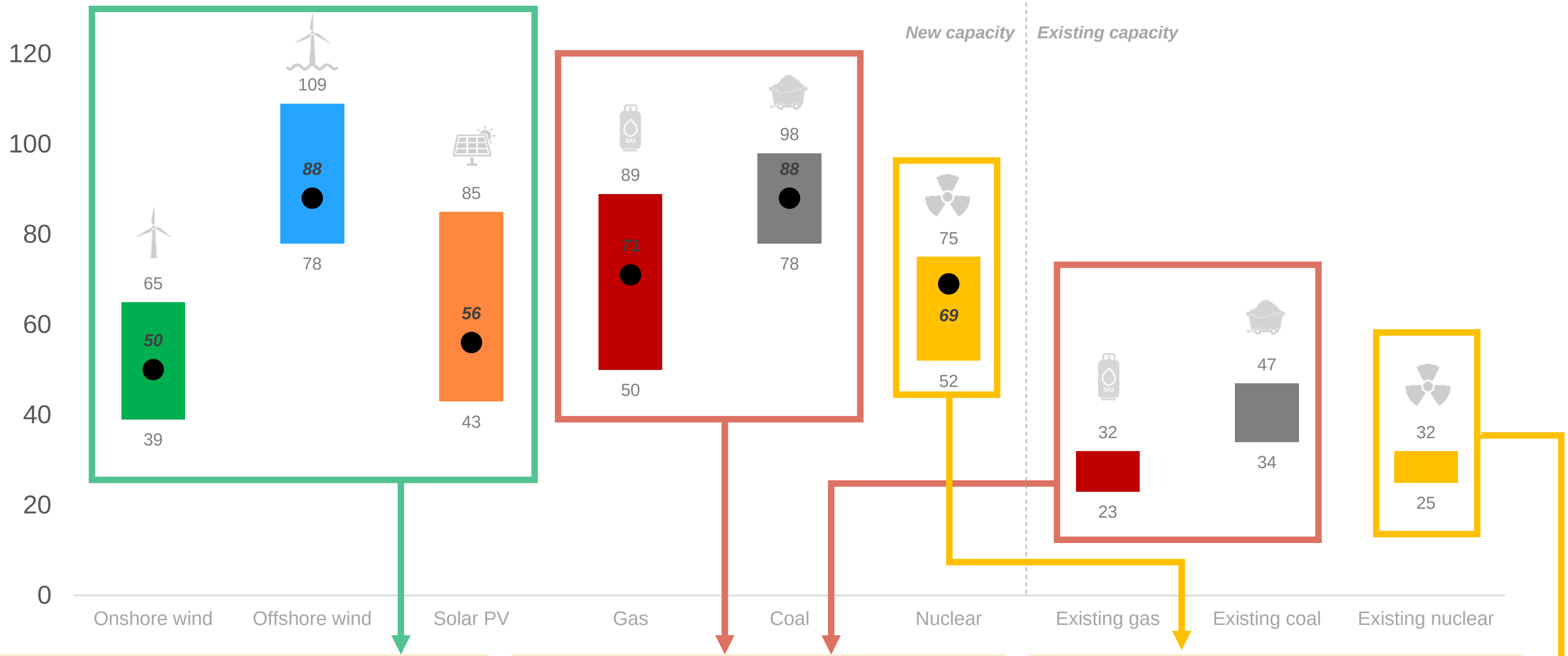
- Renewable power sources are now largely competitive with new fossil capacity on a global scale. Even offshore wind, the most expensive alternative outlined, overlaps with coal power on cost of new capacity.
- New renewables are still not competitive with existing gas power, however. Sunk capex leaves the LCOE at between 23 USD/MWh (95th percentile) and 32 USD/MWh, both below the 95th percentile for onshore wind at 39 USD/MWh.

Source: Rystad Energy research and analysis; Lazard

Trend disfavors fossil and nuclear, which faces harsher taxation and phase-outs

Global LCOE levels for various power sources (5th percentile, 95th percentile and median)

USD/MWh



European cost trend:

- *Cost set to reduce as technology further matures and benefits from scale*
- *Further set to receive subsidies to reach climate targets*
- *Has to be coupled with storage to achieve this scale, increasing the realized LCOE*

European cost trend:

- *Costs of both existing and new capacity set to increase in face of progressive EU carbon taxation.*
- *Coal set to be phased out in several countries (Germany, UK), decreasing likelihood of new capacity*

European cost trend:

- *Similar to coal, set for a phase out, for instance in Germany by 2022.*
- *Long lead times for new capacity implies little likelihood of new capacity being built.*
- *Still exposed to negative sentiment from environmentalists from the «old school»*

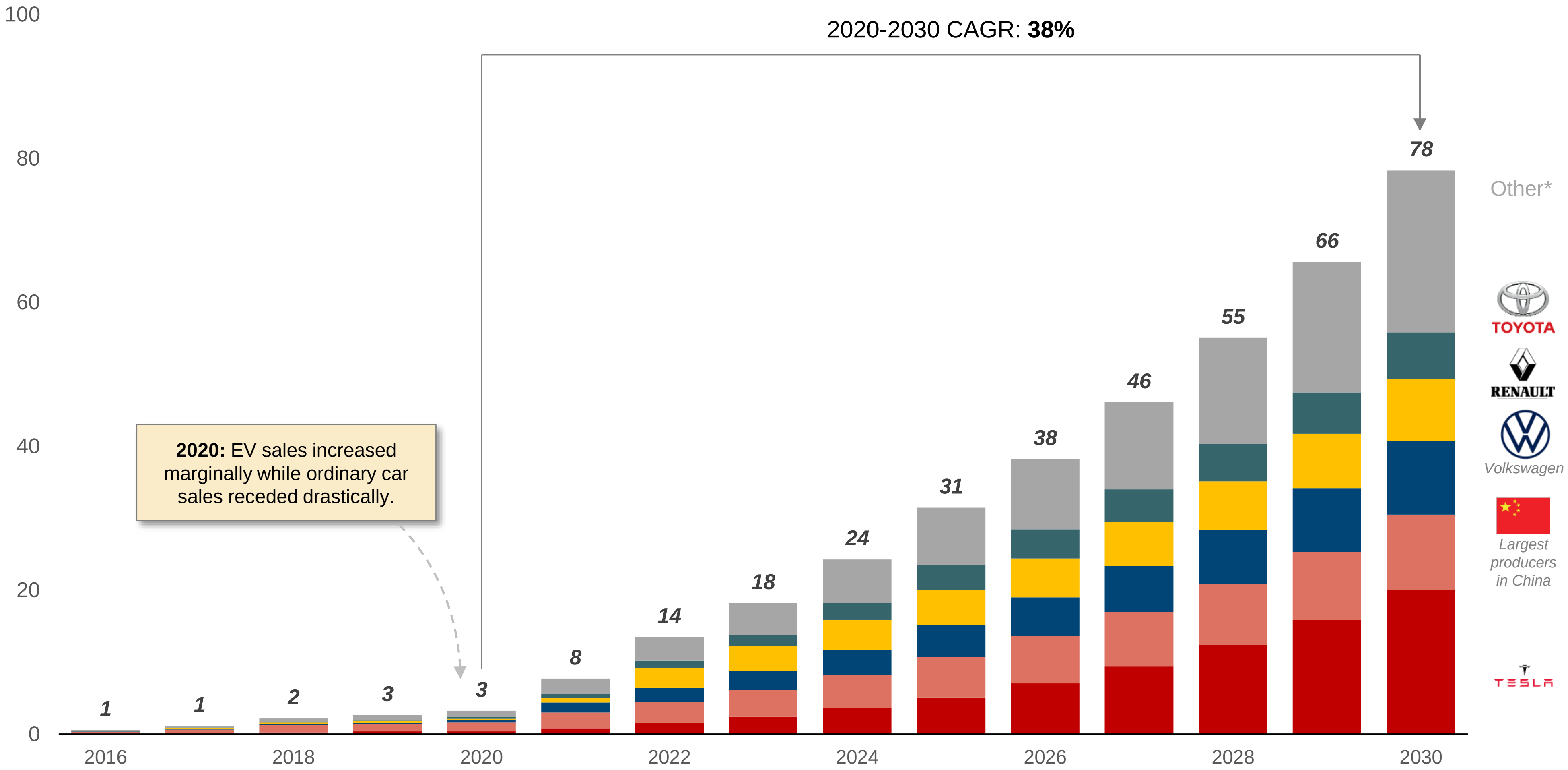
Source: Rystad Energy research and analysis; Lazard

Aggregating car manufacturer’s EV sales targets depicts rapid growth in 2020s

Battery storage

Car manufacturers’ manufacturing targets for electric vehicles (reference case)

Number of personal mobility vehicles in millions



2020: EV sales increased marginally while ordinary car sales receded drastically.

*Includes Ford, Hyundai Kia, India, BMW, Daimler/Mercedes, Volvo, Honda, Fiat Chrysler, GM;

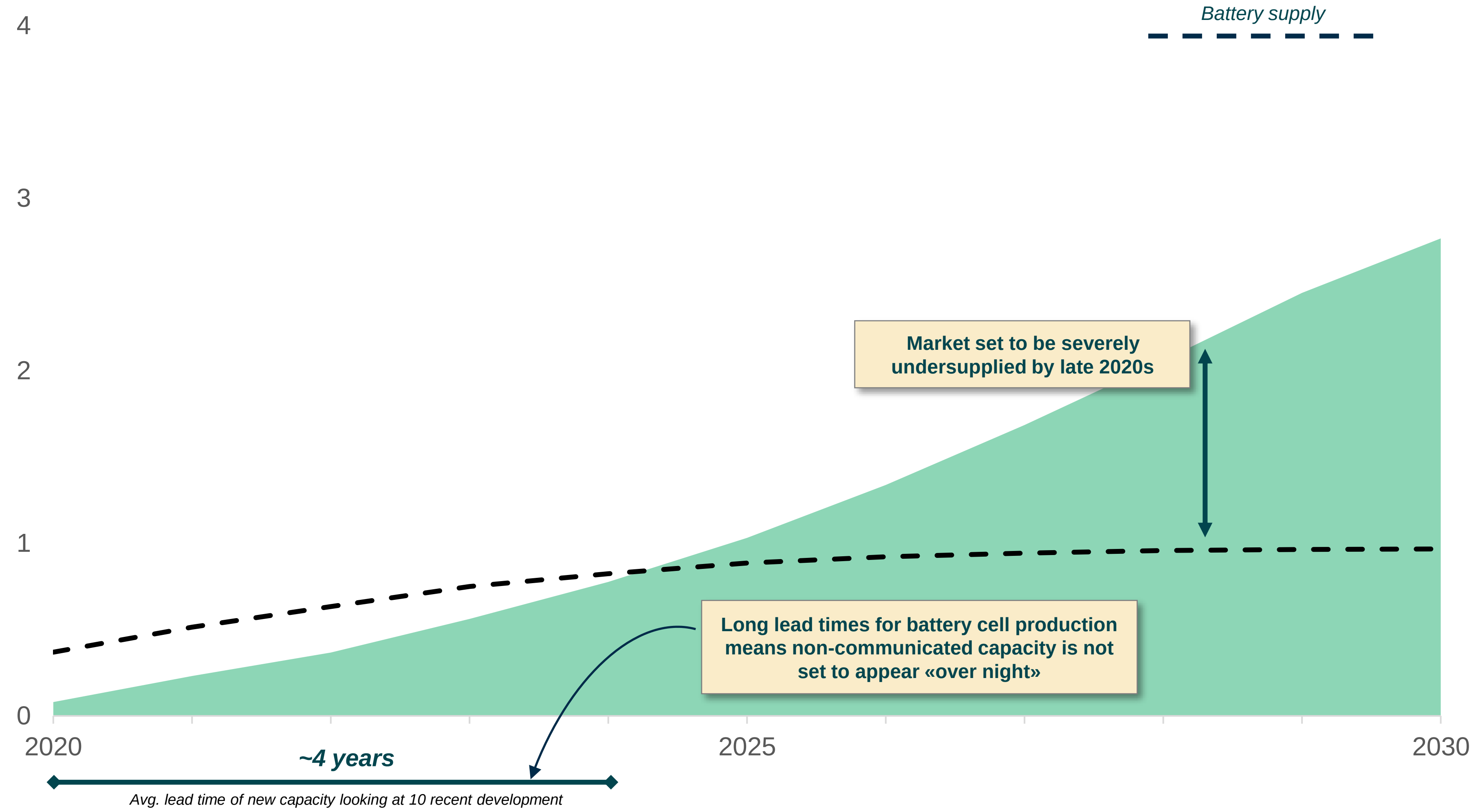
Source: Rystad Energy research and analysis; ***BEV – Battery electric vehicles, PHEV – plug-in hybrid electric vehicle; ****A scenario for society to achieve the goals of the Paris agreement

Communicated supply and lead times point to a undersupplied market in the mid 2020s

Battery storage

Annual global demand for new EV batteries and supply

TWh



Market set to be severely undersupplied by late 2020s

Long lead times for battery cell production means non-communicated capacity is not set to appear «over night»

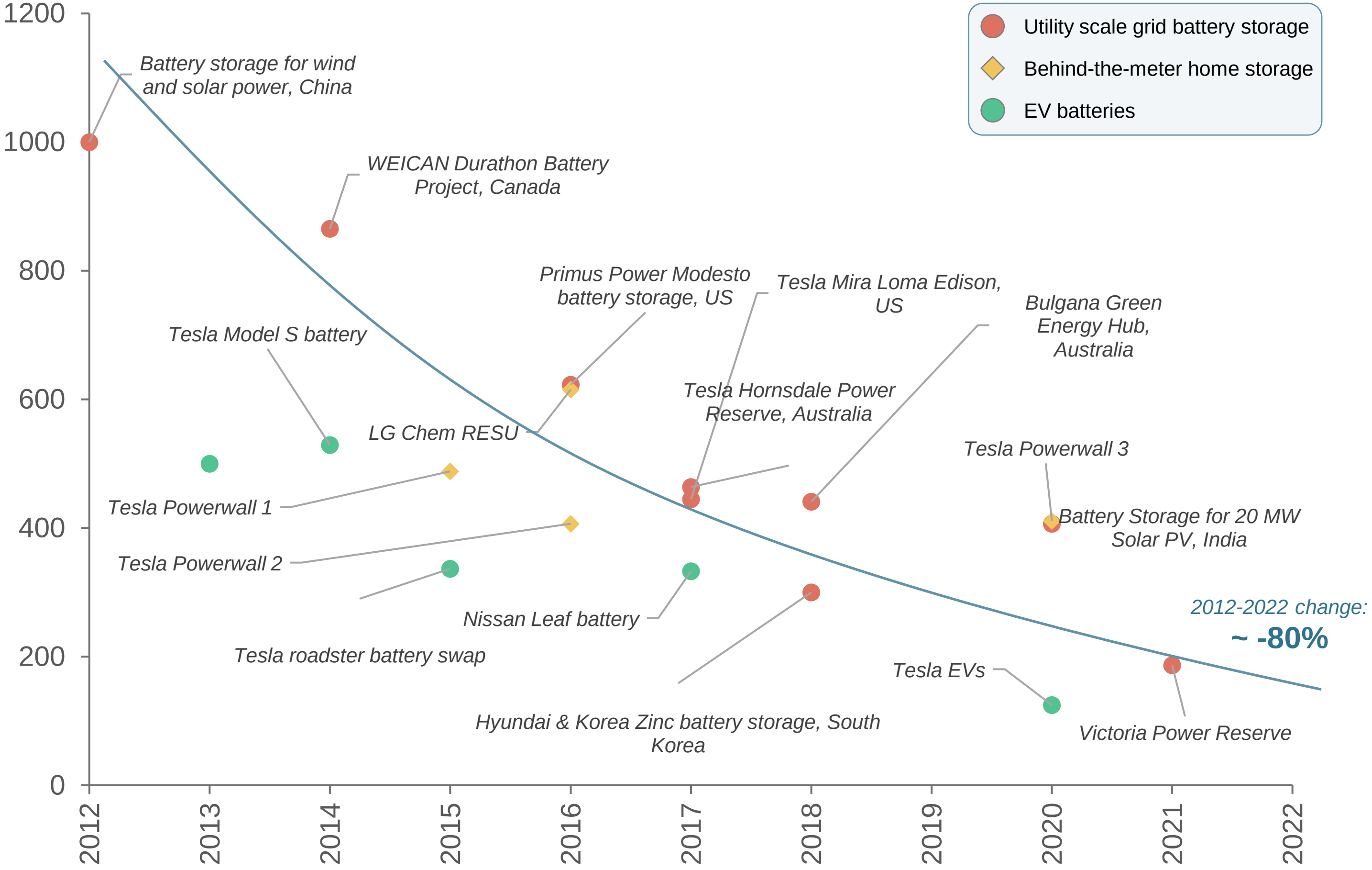
Avg. lead time of new capacity looking at 10 recent development

*Due to bottlenecks in value chain, ramp-up period, announced capacity is applied at year end, and challenges with battery cell performance, actual output is assumed to 60% of announced capacity
Source: Rystad Energy research and analysis

80% reduction in battery costs from 2012 to 2020, but improvement is flattening out

Battery storage

New battery storage capex
USD per KWh

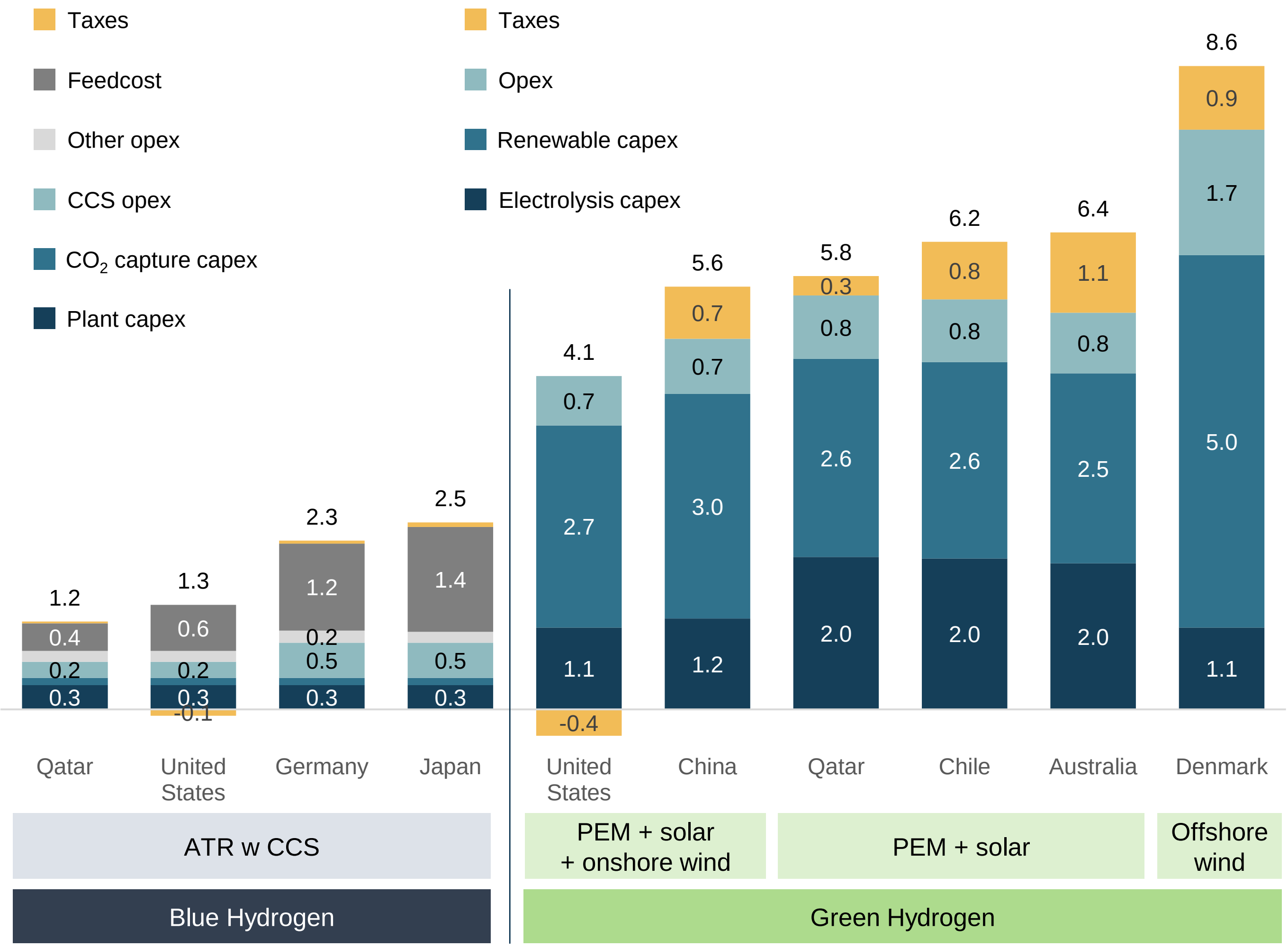


- Capital cost of new battery capacity is seen to reduce by about 80% from 2012 to 2022. The trend applies to utility scale batteries, EV batteries and home batteries.
- EV batteries are in the lower end of the spectrum, benefitting from increased maturity and scale compared to grid and home counterparts.
- The improvement curve is flattening. This may both reflect that current battery technology is nearing its potential, and that the supply chains for the components entering the batteries are being squeezed.

Source: Rystad Energy RenewableCube; Rystad Energy research and analysis

Green hydrogen currently far more expensive than its blue counterpart...

Breakdown of hydrogen production cost
USD per kilogram (kg) H_2

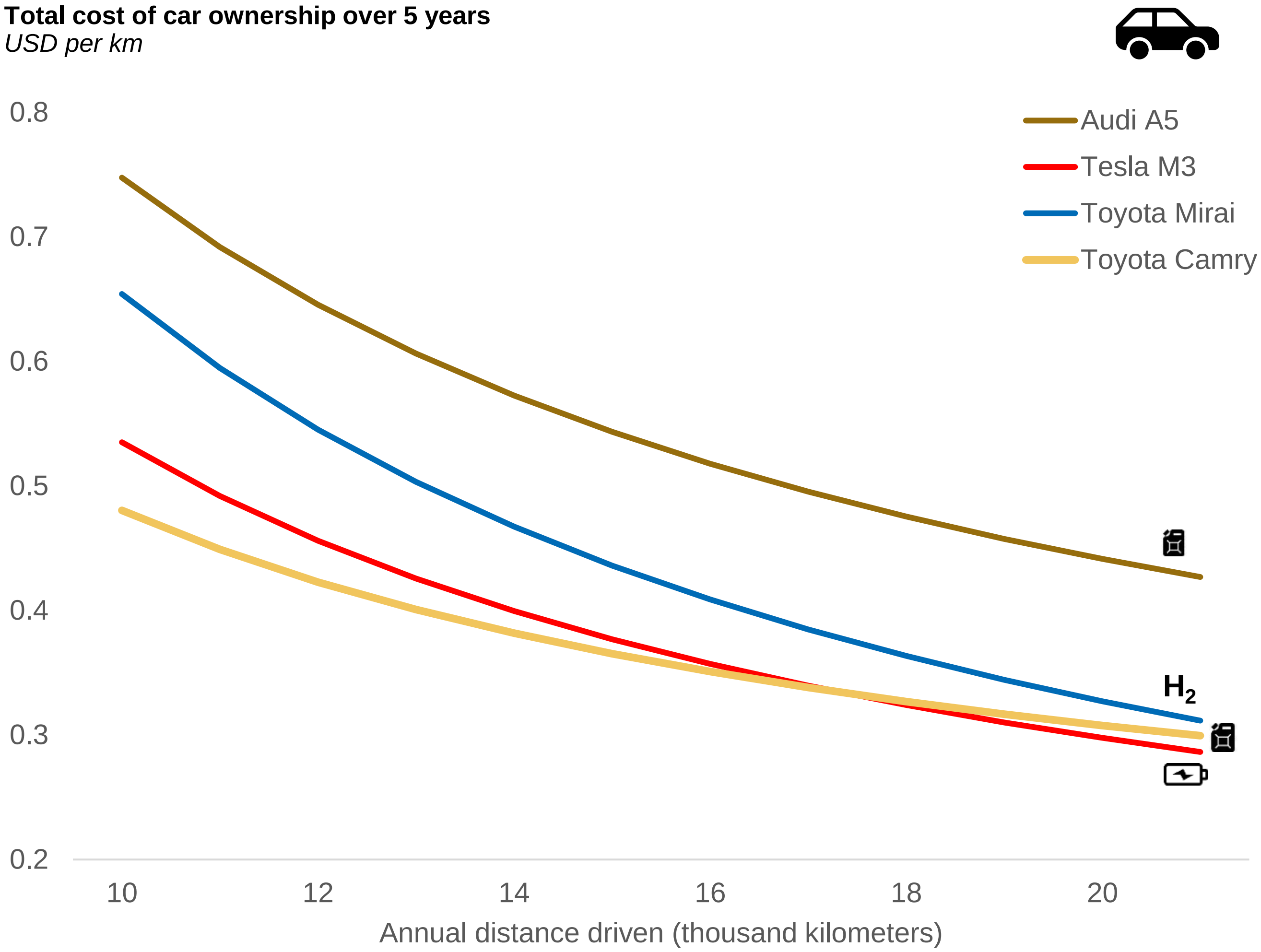


- Cost of blue hydrogen today largely outperforms green hydrogen.
- The large cost elements for green hydrogen are capex related, with the cost of the electrolyser and renewable energy for power generation representing the bulk of overall costs.
- Conversely, the large cost bulks for blue hydrogen relate to the feedstock (i.e. purchasing the natural gas needed), speaking to cheap Norwegian gas maintaining a strong competitive position given a large scale rollout of blue hydrogen.

Source: Rystad Energy Hydrogen Solutions

Battery electric and hydrogen fuel cell electric vehicles outcompete fossil over lifetime

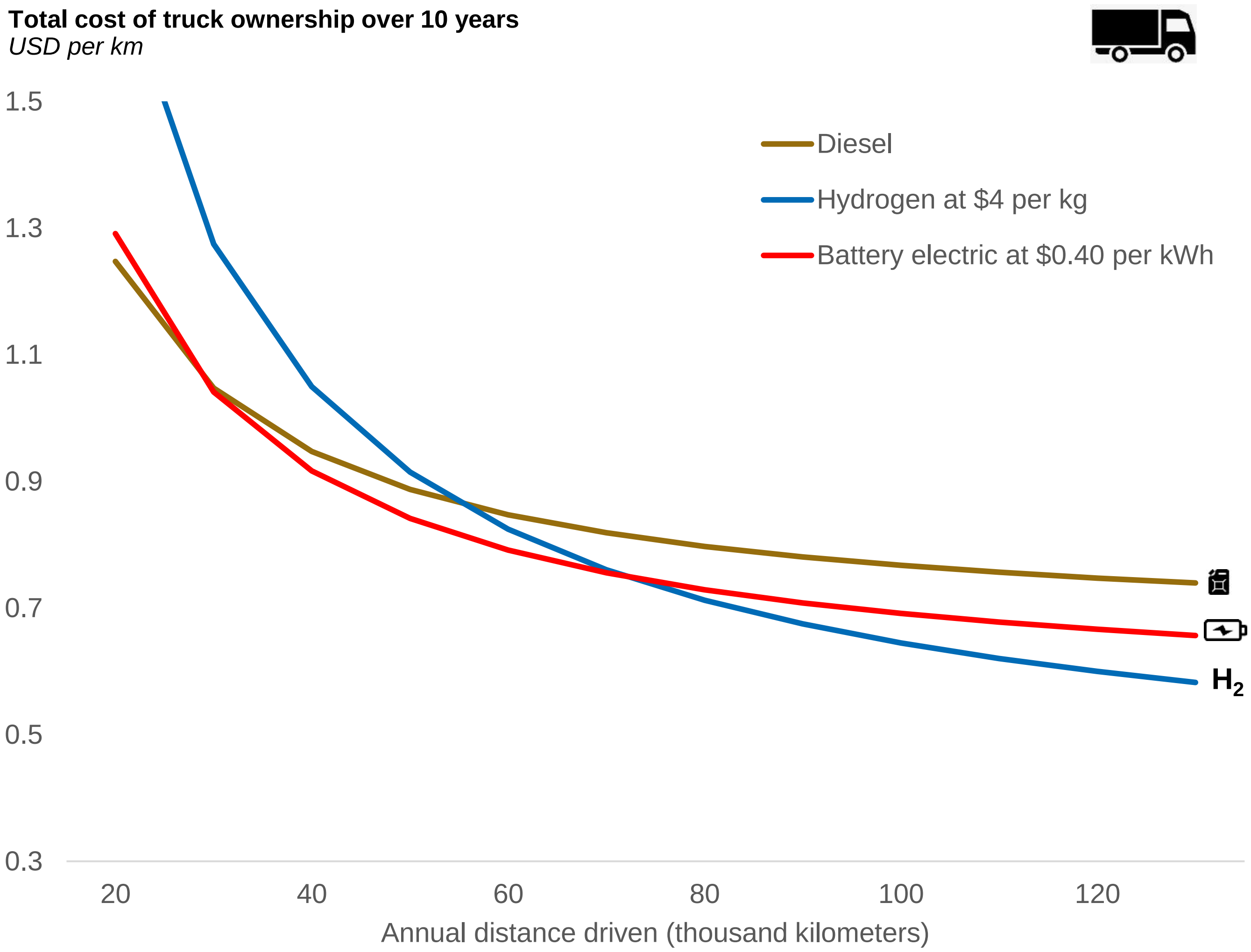
Total cost of car ownership over 5 years
USD per km



- The left chart shows an overview of car ownership costs (y-axis) for a given level of usage (x-axis).
- Regarding the lower three lines, the Toyota Camry starts out as the least expensive. It is eventually surpassed by the Tesla given that power for the Tesla is cheaper over time than fuel for the Camry.
- The Toyota Miray hydrogen fuel cell car compares at the highest levels of usage, but this is contingent on Toyota delivering on its promise to provide complementary fuel for the lifetime of the vehicle.
- Even though Toyota may be able to deliver on this, access to hydrogen filling infrastructure is bound to be scarce many European consumers, at least in the short to medium term.

Assumes 0.4 USD/KWh power prices for battery vehicle (Tesla M3), assumes complementary hydrogen for Hydrogen vehicle as per Toyota communication related to Mirar.
Sources: Rystad Energy research and analysis;

Similar trend with road freight trucks if they deliver on manufacturer specs / are used sufficiently



- A similar trend for cars can also be seen for heavy freight road transport (trucks)
- Compared to cars, these vehicles are applied more to a professional setting, and one expects usage to be higher, both in terms of years of use and kilometers traveled.
- Consequently, cost of fuel is not the only differentiator when looking at lifetime costs compared to usage, maintenance intensity also plays a part.
- Electric cars, receiving power either through a hydrogen fuel cell or a battery, have fewer rotating parts compared to their fossil counterparts. This should in theory lead to less maintenance.
- The left chart is contingent on vehicles such as the Tesla truck being able to deliver on stated maintenance intensity. This may not be viable given the relative immaturity of battery driven trucks as a technology.

Sources: Rystad Energy research and analysis; Tesla; Nikola

The energy transition disrupts oil and gas, but also opens for opportunities to pioneer new technology

Energy transition effect	Implication for Norwegian oil and gas	Technology opportunities
1. New value chains utilizing gas  *H21 project: hydrogen used the UK grid*	• While demand for gas for current uses may have peaked in Europe, it will still serve as feedstock into blue hydrogen. • Although not seen as an alternative for the very distant future, blue hydrogen may act as an important transition fuel while green hydrogen matures and scales • Feedstock represents about half of the lifetime costs of blue hydrogen, leaving cheap Norwegian supply to Europe as a favored alternative.	• Wells will be needed to store CO2 underground. • Reservoir understanding will be needed to understand candidates for storage and monitoring the CO2 once stored. • Competence on transporting CO2 to the reservoirs will also be of key importance
2. CCS as an emerging industry  *Langship project initial plans*	• Several countries' climate targets include an assumption that CCS will be applied. Norway may benefit from being an early mover in the segment with the Langship projects, despite beinhg far from the biggest point emission sources in Northern Europe (in the UK, Germany and BeNeLux) • Offshore reservoirs appear as one of the most viable options for storage of CO2, suggesting a wide overlap with oil and gas competence.	
3. More power intensive industry utilizing the Norwegian grid  *Planned Freyr battery cell factory in Mo i Rana* Threat	• Norwegian offshore installations will potentially have to compete with onshore industrial facilities for grid power. • Several operators of onshore facilities are already communicating ambitions to move away from fossil power sources. Meanwhile, power from shore to oil and gas producing platforms is being exposed to increased public scrutiny. • Furthermore, power intensive energy transiotion industries like battery cell factories are looking to Norway for its cheap, clean power, as evidenced by the prospective Morrow and Freyr facilities. • A general shortage of power may imply increased use of feedstock such as blue hydrogen to provide power	Alternate modes of consuming renewable power besides hydropower from the grid will receive increased importance. Many of these modes rely on competence in the oil and gas space. Floating offshore wind is one example, blue hydrogen is another. The market for hydrogen is likely to be heavily based on localized synthesis and consumption. Pioneering this technology on oil and gas facilities is set to provide an early mover advantage and a useful learning curve.
Opportunity ***4. New ways to electrify offshore installations***  *Hywind Tampen*	• While access to grid power may become more disputed, new ways to power offshore installations arise. • These include floating offshore wind, like the Hywind Tampen project. • They also include power platforms with hydrogen, or using gas power plants in conjunction with CCS to provide power from the shore.	
5 Capital flows heading in new directions  **«Grønne» aksjer skyter til værs på børsen - men eksperter er skeptiske til prisingen: - Det lukter intuitivt dyrt** *Dagens Næringsliv on high performing «green» stocks*	• Both subsudies and capital distributed through banks has increasingly found its way towards energy transition related industries in the previous couple of years. • Meanwhile, E&P companies on NYSE like ExxonMobil and Chevron are struggling with low valuations, despite in some cases showing high cash flows. • In Norway, there was a record number of listings on Euronext Growth (previously Merkur Markets) in 2020, in large part to the listing of companies that associate themselves with the energy transition. • Listings of oil service companies have meanwhile been few.	Raising capital has become more cumbercome for oil service comapnies. The winners will be those that demonstrate applicabilitiy to the energy transition.

Source: Rystad Energy and analysis

Several large Norwegian land facilities are “next in line” on NVE’s electrification list

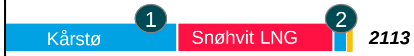
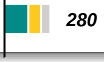
NVE

In a report published in June 2020, NVE outline 7 Norwegian industrial facilities on land which are the most suitable for electrification. These will apply «existing» or «new» ways of electrification, meaning that the necessary processing equipment is either available or in the development phase, respectively. In some cases, electrification of these facilities will not only draw power from the grid, it will also imply displacement of natural gas as a feedstock.

The 7 electrification candidates:

Existing tech.
1. Kårstø
2. Kollsnes
3. Mongstad refinery
4. Yara Herøya
5. Borregård*

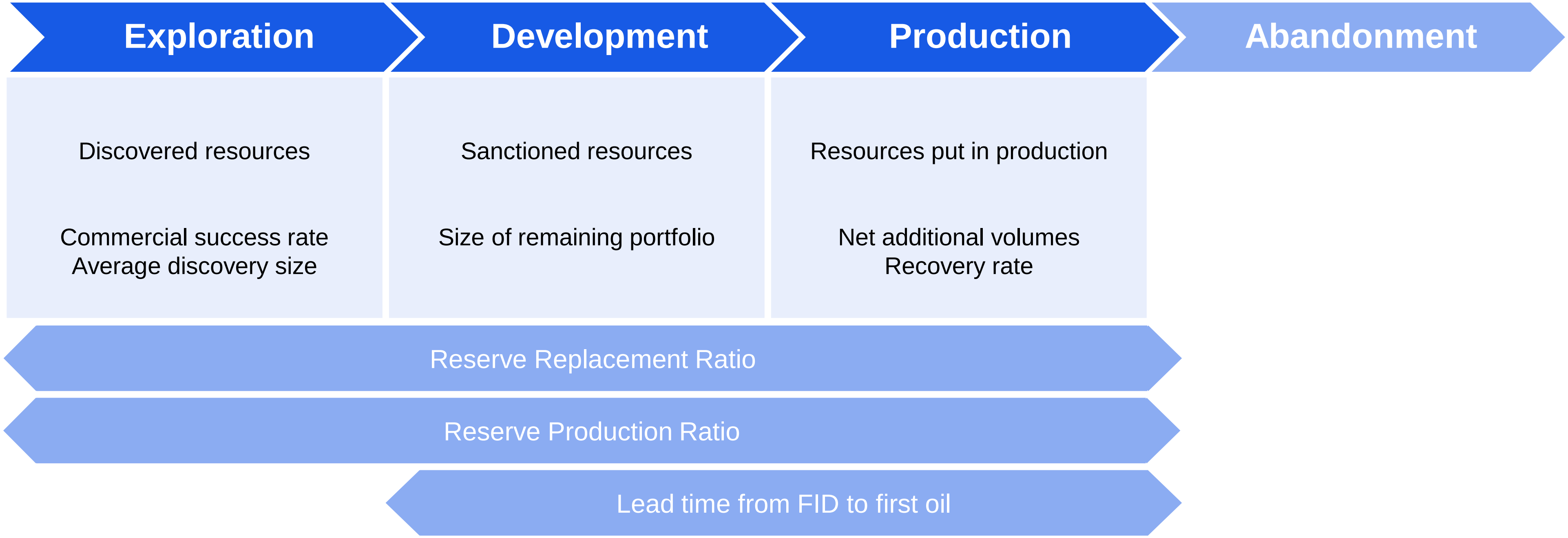
New tech.
6. Ineos Rafnes
7. Tjeldbergodden

Sector (by emissions)	**Emissions (‘000 tons)**	**Emissions source**	**Large contributors**	**Comment on emissions and utilization of natural gas**
Aluminum production		Combustion of natural gas and calcination process	Hydro Alcoa	Natural gas used in anodes, alumina calcination and in electrolysis
Processing of natural gas		Combustion	equinor GASSCO	Combustion of natural gas during processing
Refining of petroleum products		Combustion of natural gas	ExxonMobil equinor	Combustion of gas during distillation and purification of petroleum products
Manufacturing of ferro-alloys		Melting of coal as a reducing agent and combustion of LNG	Elkem WACKER eramet	Combustion of LNG for power production purposes and melting of coal as a reducing agents drives up emissions
Silicon production		Reduction of coal and possibly combustion of natural gas	Elkem	Combustion of LNG for power production purposes and melting of coal as a reducing agents drives up emissions
Cement production		Calcination process	NORCEM	Calcination process requires natural gas in the same way as alumina production, possible utilizations of natural gas as power source
Fertilizer production		Reformation of natural gas	YARA	Reformation of natural gas to produce gray hydrogen utilized for ammonia production
Petrochemical industry		Combustion of fossil fuels	INEOS	Combustion of natural gas and processed natural gas utilized as feedstock for olefins production
Waste treatment		Waste incineration	fortum BIR BEDRIFT	Emissions from waste burning generating CO2
Metals production		Heating with fossil fuels	TiZir celsa	Combustion of natural gas for power generation
Methanol production		Combustion of natural gas	equinor	Natural gas goes into the conventional steam reforming process of methanol distillation
Lime and plaster production		Combustion of fossil fuel and gas in calcination	NorFraKalk sma mineral	Natural gas used as power source and during the calcination process.

*Not represented. Belongs to the sector “Refining of biological products”, with a low share of overall emissions; Sources: Rystad Energy research and analysis.

Report contents

Volume dimension: Metrics for Norwegian competitiveness



Exploration

Discovered resources

Commercial success rate
Average discovery size

Development

Sanctioned resources

Size of remaining portfolio

Production

Resources put in production

Net additional volumes
Recovery rate

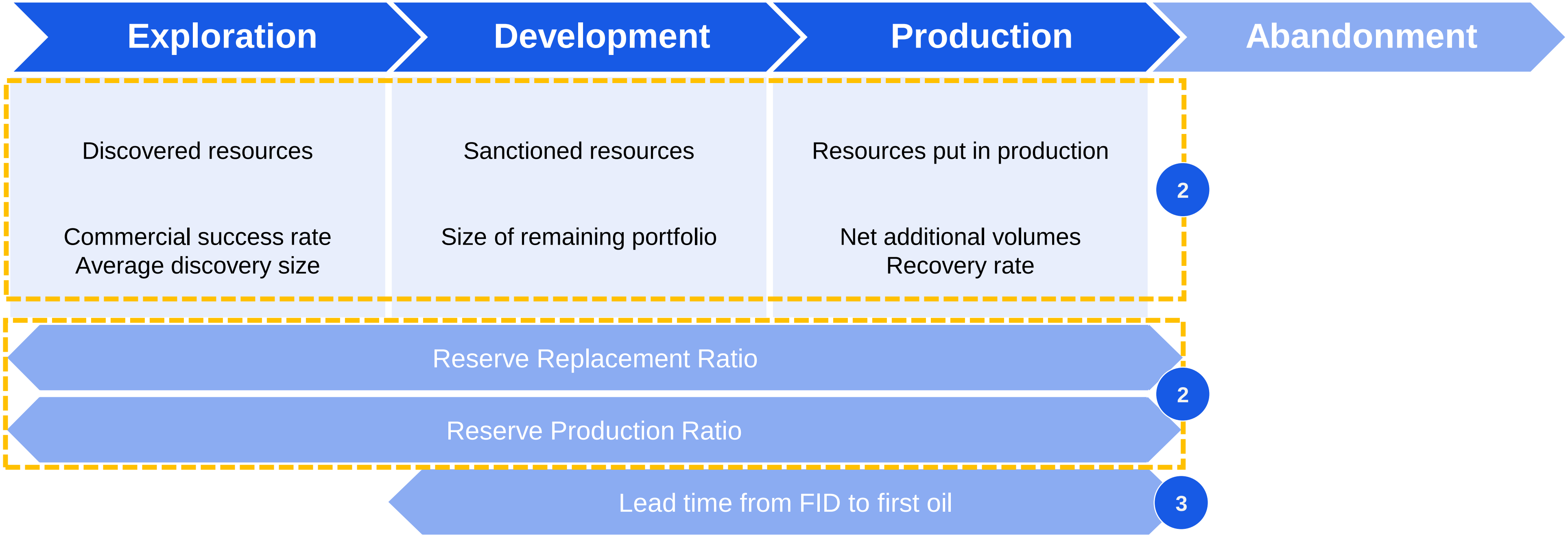
Abandonment

Reserve Replacement Ratio

Reserve Production Ratio

Lead time from FID to first oil

Volume dimension: Chapter synopsis



Chapter synopsis

1

Norway is a small oil and gas region in a global perspective, punishing resource growth in absolute terms. The Norwegian continental shelf is becoming mature, which is supported by the fact that more resources are put in production than discovered/sanctioned in 2019 and 2020. The NCS is highly competitive on commercial success rate and recovery rate, but the average discovery is small and the remaining resource portfolio is somewhat limited.

2

Reserve replacement of oil reserves have grown significantly over the last decade, while gas reserves are lagging. Infill drilling is more common on oil fields than gas fields.

3

Subsea tie-backs on the NCS are competitive on lead time with all offshore oil and gas regions but beaten by North America shale and NAm conventional onshore.

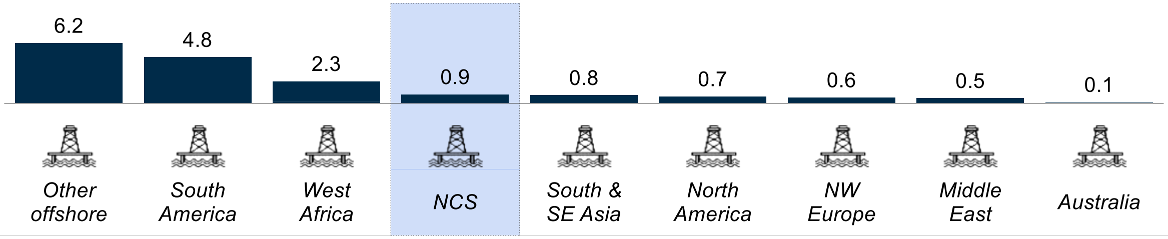
The NCS is moving towards peak production with more resources put in production than discovered and sanctioned

1

Key indicators for competitiveness

Comment

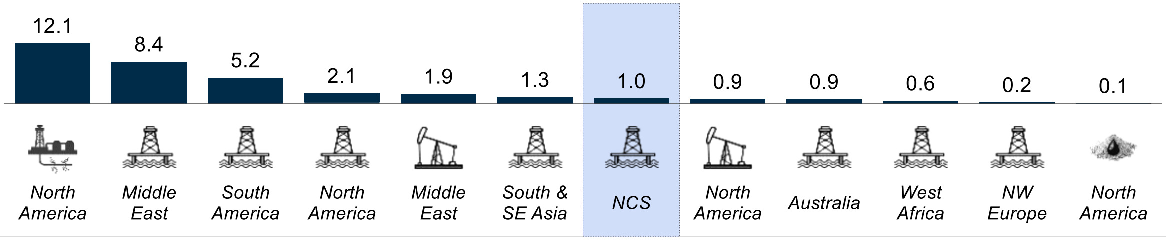
Discovered resources* (Bboe)



**Sum of commercial discovered resources in 2019 and 2020. Only offshore. Includes only commercial discoveries where public information is available.*

Almost 1 billion boe has been added to the discovery portfolio on the NCS in 2019 and 2020. Discoveries like Slagugle, Liatårnet, Froskelår and Bergknapp have contributed to increase the NCS discovery portfolio. Among the offshore regions, most volumes have been added in South America and West Africa. In the other onshore post, Russia has contributed with large volumes.

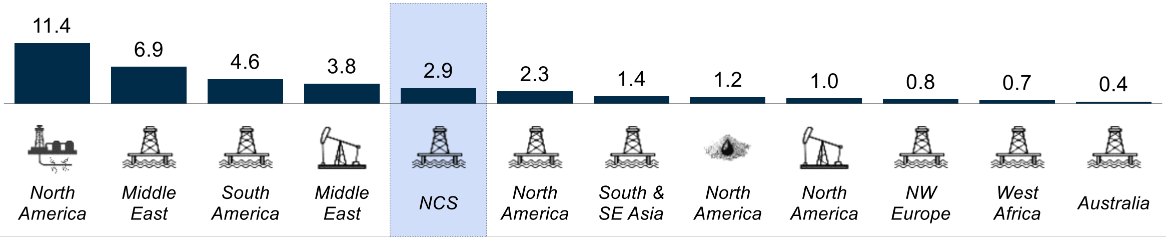
Sanctioned resources (Bboe)**



***Sum of sanctioned volumes in 2019 and 2020.*

More than 1 billion boe has been sanctioned on the NCS through 2019 and 2020, with Johan Sverdrup phase 2 as the main contributor. This still puts us way behind Middle East and South America offshore which have sanctioned the most volumes. Middle East has sanctioned a couple of giga fields like Berri and Marjan, while Buzios and Mero in Brazil have contributed to South America offshore.

Sum of resources put in production* (Bboe)**



****Sum of resources put in production in 2019 and 2020.*

Fields put in production on the NCS in 2019 and 2020 are estimated to contribute with 3 billion boe over the field lifetime. Johan Sverdrup phase 1 with 2.3 billion boe in reserves consists of about 80% of the total resources put in production over the two last years. This means excluding Johan Sverdrup would have assigned Norway to the bottom tier of the scale, only above West Africa.

- Due to the start-up of Johan Sverdrup phase 1, 3 times as much resources have been put in production as discovered the last two years. This indicates a move towards peak production.
- Mostly subsea tie-back possibilities among last two years discoveries.
- Johan Sverdrup phase 2 sanctioned in 2019 holds the main share of sanctioned resources.

1) Northwest Europe excluding Norway
Source: Rystad Energy UCube; NPD

Offshore
Shale unconventional
Onshore conventional
Oil sands unconventional

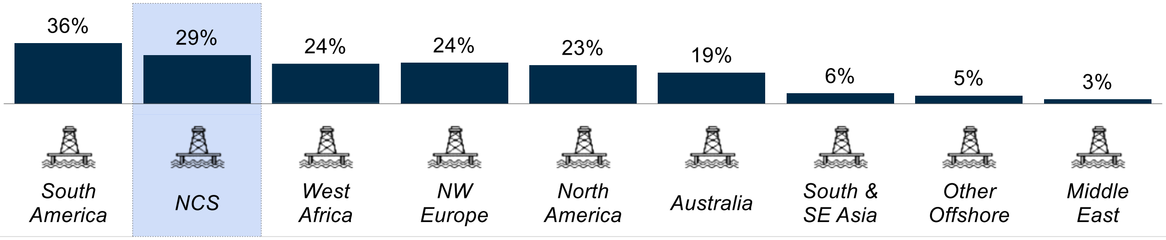
High success rate, yet small discoveries gives little contribution to low “bank” of discoveri

1

Key indicators for competitiveness

Comment

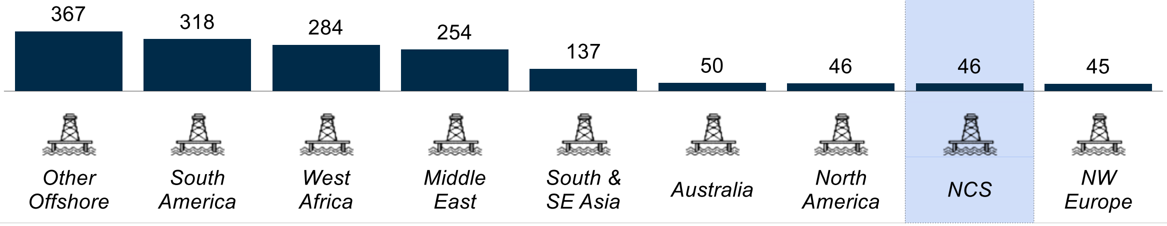
Commercial success rate* (%)



*Number of wildcats which lead to commercial discoveries divided by number of wildcats drilled. Only offshore. Includes only commercial discoveries where public information is available. Average of 2019 and 2020.

While the number of wildcats on the NCS was reduced from 43 in 2019 to 29 in 2020, the commercial success rate increased from 21% in 2019 to 45% in 2020. 2019 and 2020 average numbers show that NCS was only beaten by South America in terms of success on offshore wildcats in the period.

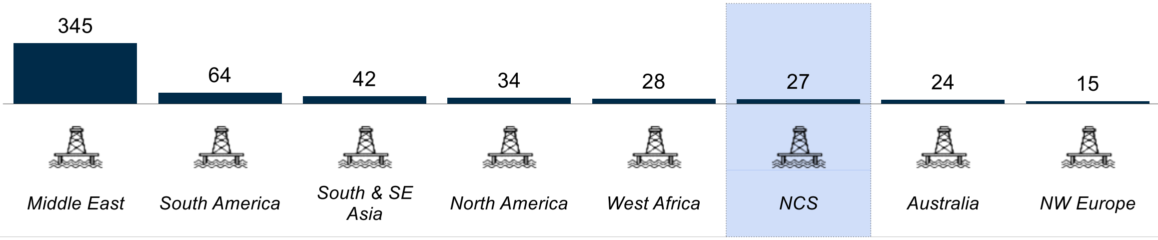
Average discovery size (Mmboe)**



**Only offshore. Includes only commercial discoveries where public information is available. Average of 2019 and 2020.

In terms of average discovery size, the NCS has an average of 46 mmboe per discovery over the two previous years. Other mature offshore regions like Northwest Europe and North America offshore are at the same level. The elevated level in the Middle East can be explained by two large discoveries.

Size of remaining portfolio* (Bboe)**



***Total volumes in fields in production, under development or discovered, but not yet produced as of 1.1.2021.

In this context, the NCS is a small oil and gas region. In the Middle East offshore supply segment, 439 billion boe of commercial resources not yet produced. NW Europe offshore with the Netherlands, UK and Denmark is the most mature region in this context, with only 15 billion boe left in the commercial portfolio.

- The NCS is highly competitive when it comes to commercial success rate in exploration since 2019.
- Average discovery size is low, another signal of a mature region driven by the North Sea and Norwegian Sea and no success in the Barents frontier region.
- NCS is a small oil and gas region in terms of remaining resources but shows significantly more potential than the UK.

1) Northwest Europe excluding Norway
Source: Rystad Energy UCube; Rystad Energy RigCube

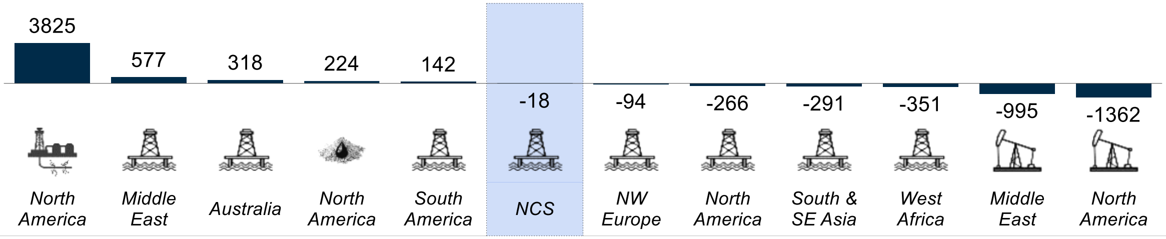
Offshore
Shale unconventional
Onshore conventional
Oil sands unconventional

Net added volumes 2015 to 2020 is negative - RRR figure below the 1.0 threshold

Key indicators for competitiveness

Comment

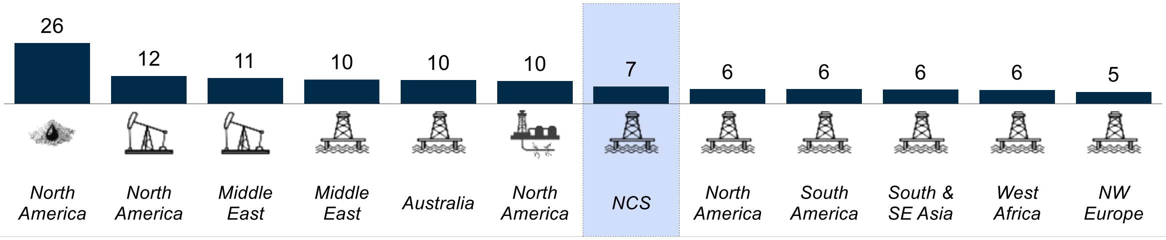
Net additional volumes* (Mmboe)



*Net additional production volumes from 2015 to 2020.

North American shale is the supply region which has grown by far the most in terms of annual production since 2015 adding 3800 mmboe/y. COVID-19 has had an impact on production in some regions due to production shutdowns. In total, oil demand dropped by 10 million bpd y/y. OPEC decided to cut production by about 9 million bpd in June 2020, still slowly ramping up production to 2019 levels.

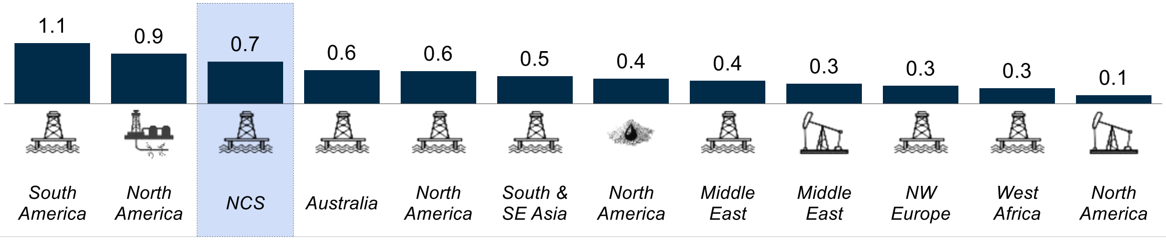
RP ratio**



**Remaining 1P reserves as of 1.1.2021 over produced volumes in 2020.

1P reserves as of 1.1.2021 over 2020 produced volumes show that North American shale has the longest reserve pipeline amongst the supply regions. NW Europe (excl. Norway), mainly consisting of the UK, has a low RP ratio of 5, which shows the decline in potential new developments in the mature region. Denmark has also decided to quit all oil and gas production on the DCS by 2050.

Reserve replacement ratio***



***Sum of sanctioned volumes by approval year over produced volumes from 2015 to 2020.

The NCS has replaced 74% of the produced volumes in the period from 2015-2020 with new sanctionings. This means reserve growth has been healthy, being able to add almost all reserves produced since 2015 only by new sanctionings. South America is the only region being able to grow reserves through the period.

- Production on the NCS stable since 2015, by far most added volumes from North American shale.
- With currently remaining 1P reserves, the NCS has a healthy reserve pipeline.
- NCS reserve replacement ratio at 0.7 only from new sanctioned fields, even higher including reserve growth in existing fields.

1) Northwest Europe excluding Norway
Source: Rystad Energy UCube; NPD

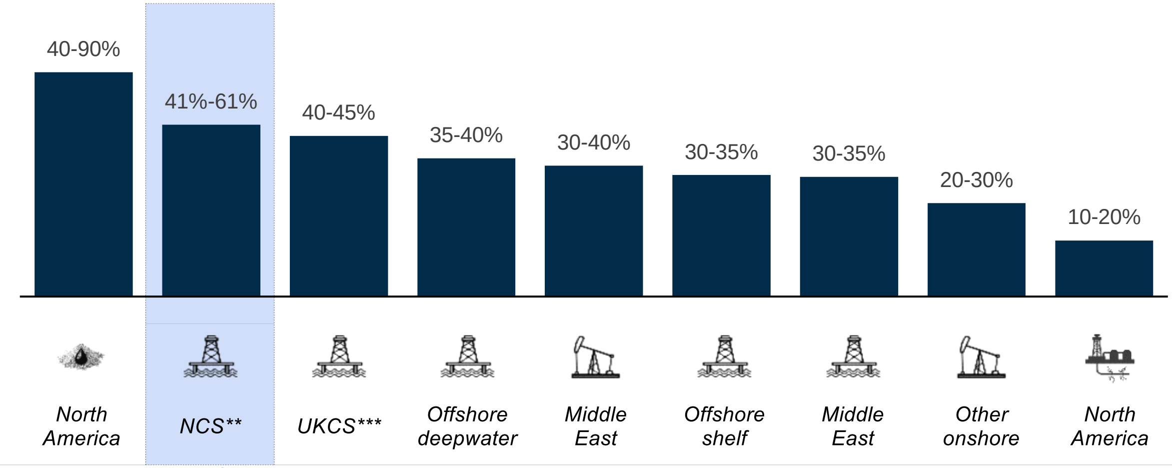
Offshore
Shale unconventional
Onshore conventional
Oil sands unconventional

NCS highly competitive on recovery rates, only beaten by NAm oil sands

Key indicators for competitiveness

Comment

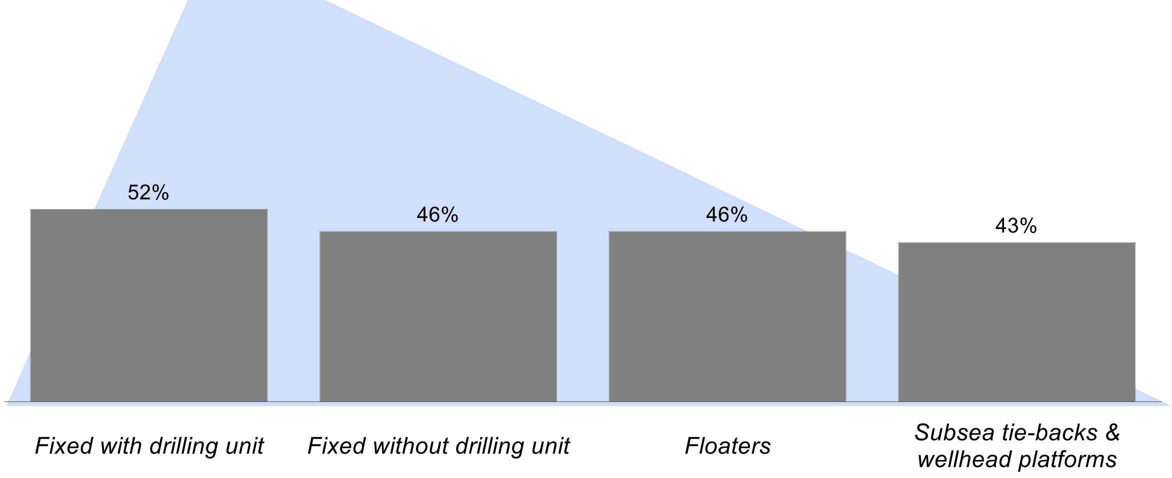
Recovery rate*



The NCS currently has an average planned recovery rate of 46%. The average is 41% for oil fields and 61% for gas fields. The UKCS has an average planned recovery rate of 43%, stated in a report from UK Oil and Gas from 2017. Shale has seen impressive developments in the later years, with some plays reaching up to 20% recovery rate. The recovery rate development in shale comes from learning curve effects.

**Average recovery rates in oil fields. Percentage of oil initially in place recovered. 40-70% recovery in oil sands is using in situ techniques, mining at 90%.*
***According to NPD Resource Accounts 2020. ***According to UK Oil and Gas Recovery factor reporting.*

NCS average oil recovery rate on oil fields****



Average oil recovery rates from oil fields on the NCS show that fields with platform drilling have the highest planned oil recovery. This might be due to the possibility of drilling new wells continously at low cost. Other facility types needs to mobilize offshore drilling rigs at a much higher cost per new production well.

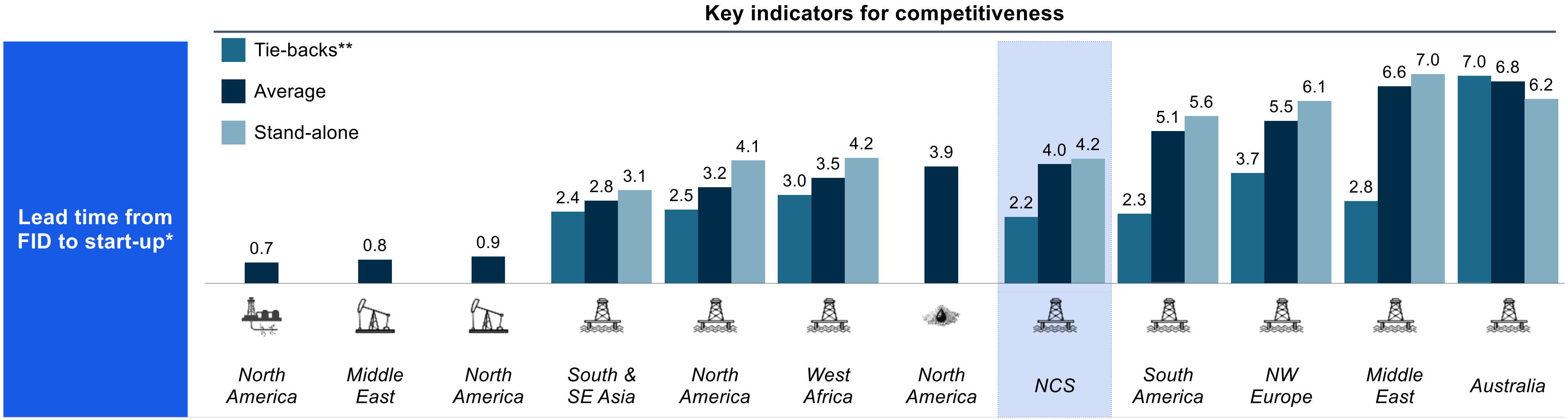
*****Average oil recovery rate on oil fields on the NCS according to NPD Resource Accounts 2020. Only oil reserves and oil resources included.*

Source: Rystad Energy research and analysis; NPD

Offshore *Shale unconventional* *Onshore conventional* *Oil sands unconventional*

NCS subsea tie-backs competitive on lead time with all regions except NAm

3



*Lead time from FID to production start-up. Fields with start-up from 2015-2020 are included. Error margin of +/-0.5 years. Weighted average. **Tie-backs includes subsea tie-backs, wellhead platforms and extended reach.

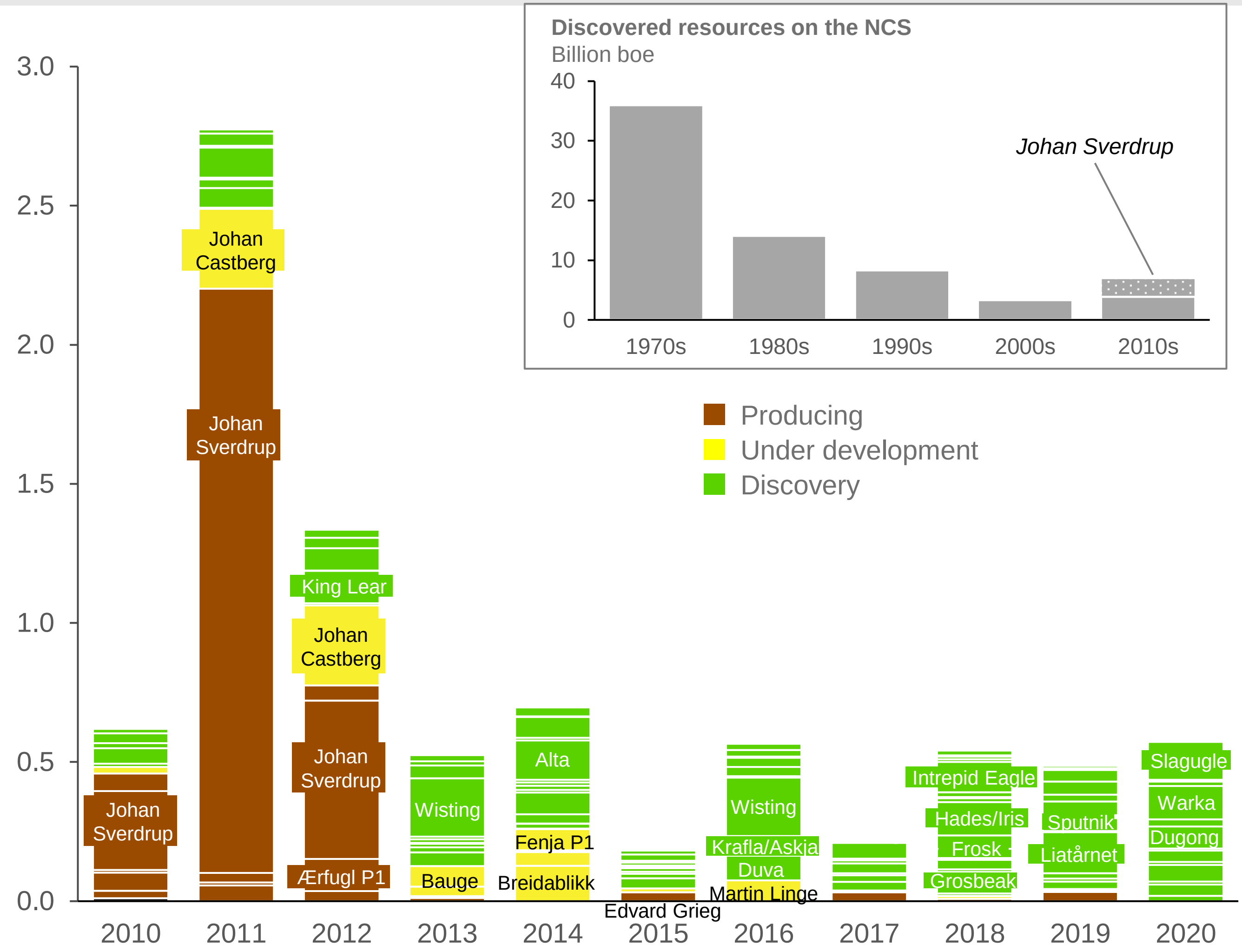
- Tie-backs have significantly lower lead time than a stand-alone platform on average on the NCS. Subsea tie-backs on the NCS are the most competitive amongst all offshore regions in terms of lead time, only beaten by North America shale and North America conventional offshore.
- Examples of subsea tie-backs with short lead time which have started production on the NCS since 2015 are Sindre, Bøyla, Byrding and Tor II.
- Stand-alone platforms set in production since 2015 are Johan Sverdrup phase 1, Valemon, Aasta Hansteen, Gina Krog, Edvard Grieg, Ivar Aasen, Goliat and Knarr.
- Lead time on stand-alone facilities are competitive with all offshore regions, only beaten South & SE Asia, but less competitive compared with other supply segments.
- Lead time for North American shale is estimated using the average cycle time from the permit is given to first oil.

Source: Rystad Energy UCube; Rystad Energy ShaleWellCube

Offshore
Shale unconventional
Onshore conventional
Oil sands unconventional

Few new discoveries with stand-alone development potential over last years

Discovered resources (by asset) by discovery year and life cycle
Billion boe



- Apart from significant development projects such as Johan Sverdrup and Johan Castberg, the last ten years have been disappointing in terms of new discoveries
- During the last six years, almost no discoveries with stand-alone development potential have been made.
- 2015 and 2017 were very disappointing exploration years.
- 2018 to 2020 has been stable in terms of discovered resources with about 550 mmboe discovered on average the last three years.
- 2020 was a good exploration year on the NCS considering the expex cuts caused by COVID-19.

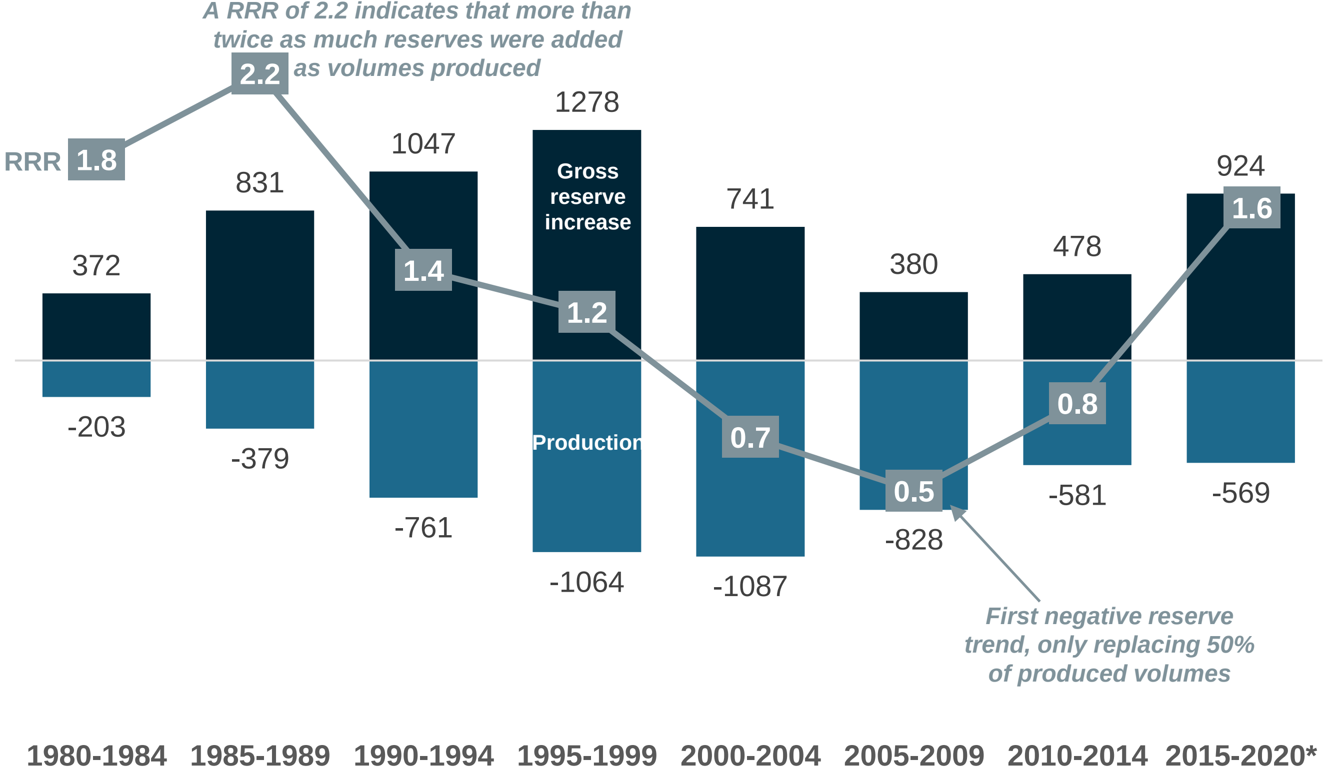
Source: Rystad Energy UCube

Oil reserve replacement back at pre-1990 levels since 2015, gas reserve replacement only at 30% of produced volumes

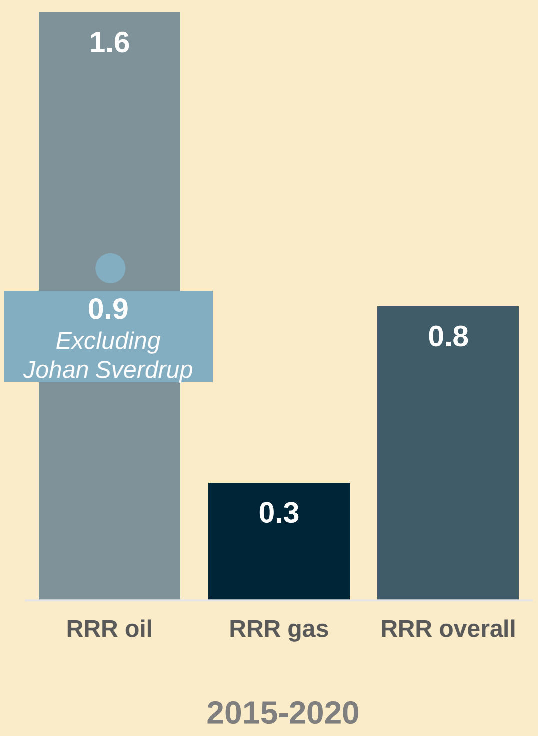
Average gross increase in oil reserves // Production
Million boe

Reserve replacement ratio[1] (RRR)

[1]Gross reserve increase over produced volumes



RRR



- With an average RRR (oil) of 1.6 from 2015 to 2020, 160% of the oil volumes produced in the period were replaced with new oil reserves. Reserve growth both from new sanctioned fields and additions in already producing fields are included.
- Looking at total reserve replacement, also including gas, NCS has a RRR of 0.83 from 2015-2020. This means gas has not seen the same reserve growth as oil. Infill drilling and other recovery improving measures are significantly less commonly applied on gas fields and gas discoveries far from existing infrastructure are difficult to develop from a commercial perspective.

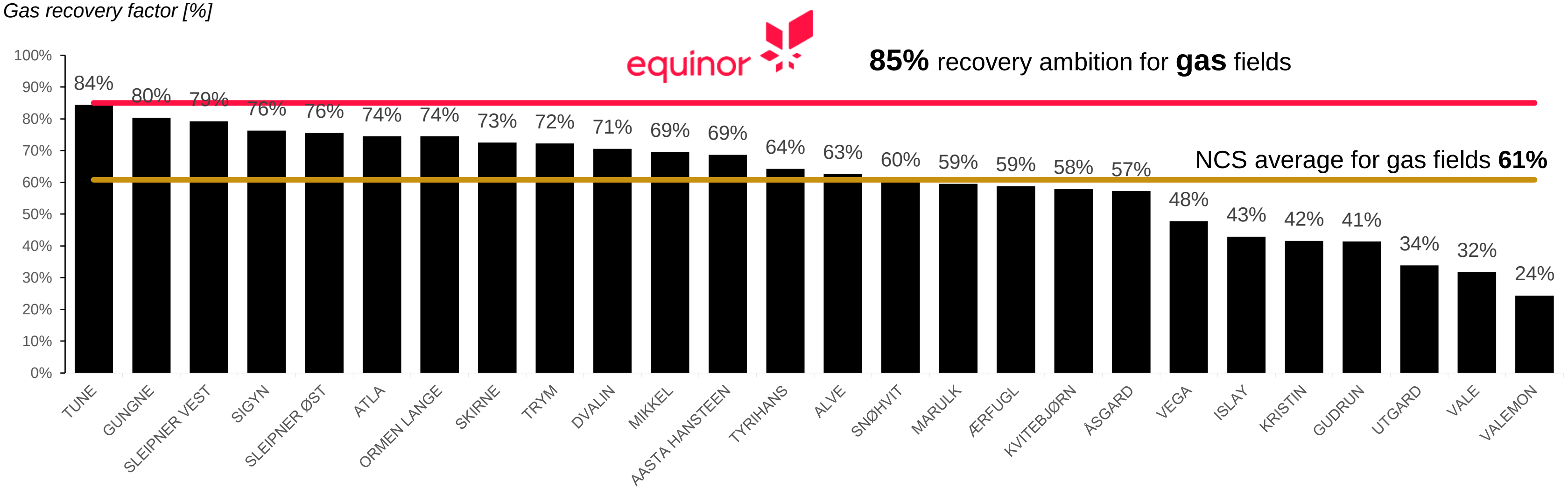
*Including 2020 into last period to include COVID-19 effects, keeping the natural shift from 2014 to 2015.; **Including average of reserve replacement both in oil and gas. Only new sanctioned volumes.
Source: Rystad Energy research and analysis; NPD

Equinor’s ambition of recovery implies significant reserve growth in existing fields

Planned recovery rates on the NCS

Gas recovery factor on **gas** fields*

Gas recovery factor [%]

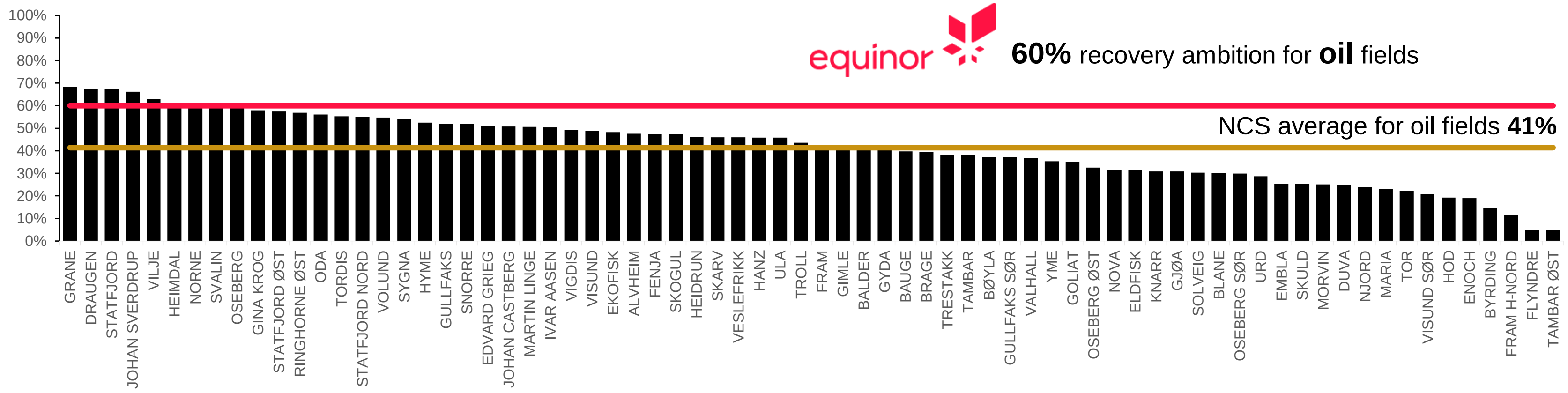


85% recovery ambition for **gas** fields

NCS average for gas fields **61%**

Oil recovery factor on **oil** fields*

Oil recovery factor [%]



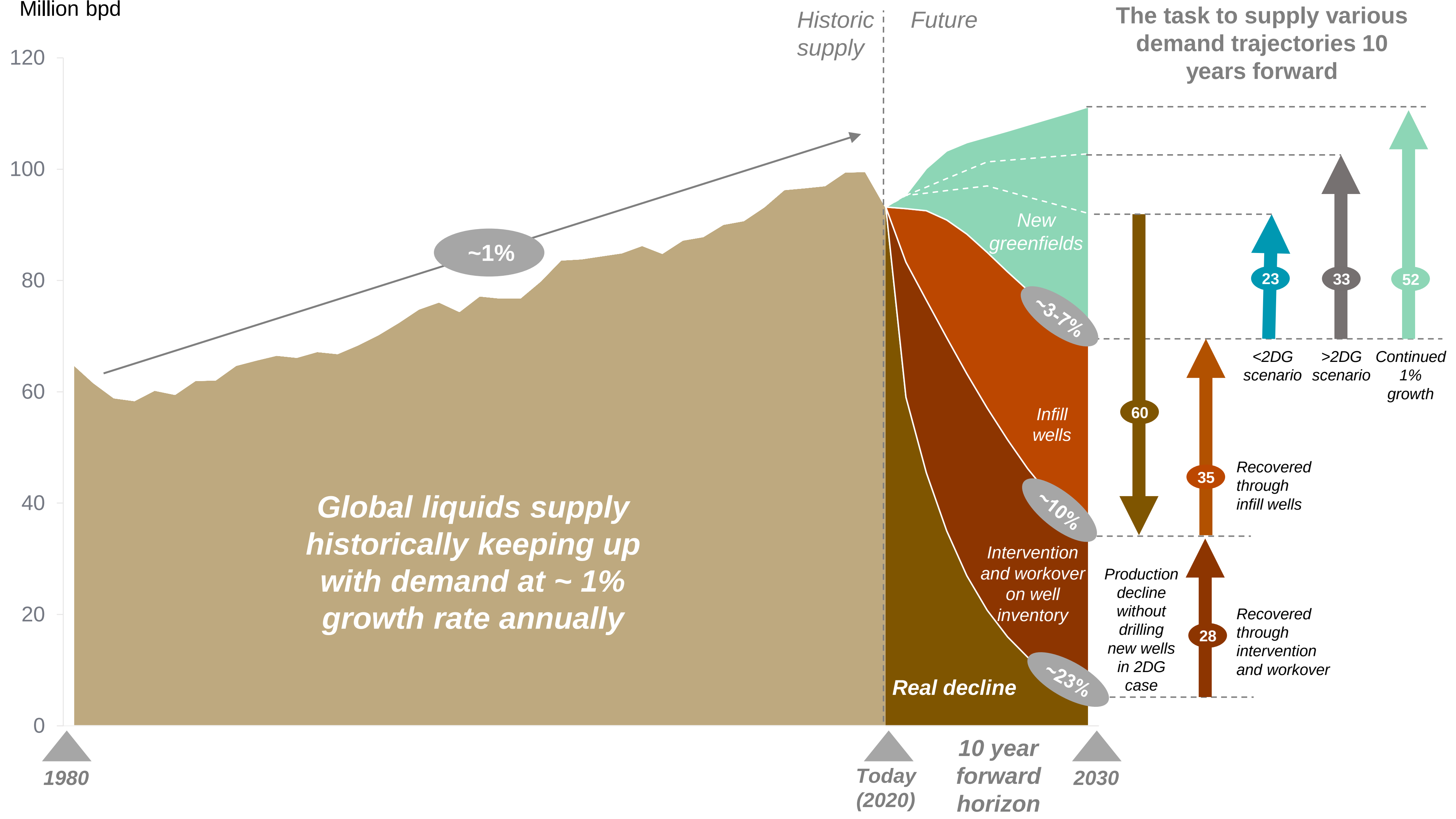
60% recovery ambition for **oil** fields

NCS average for oil fields **41%**

*Gas recovery factor includes only gas reserves in field over gas resources in place, while oil recovery factor includes only oil reserves in field over oil resources in place.
Source: Rystad Energy research and analysis; NPD (Resource accounts 2020)

New supply key to offset field decline, but infill and workovers make sizable contribution

Global liquids demand scenarios vs. liquids production potential by current status of supply
Million bpd



Source: Rystad Energy UCube; Rystad Energy OilMarketCube

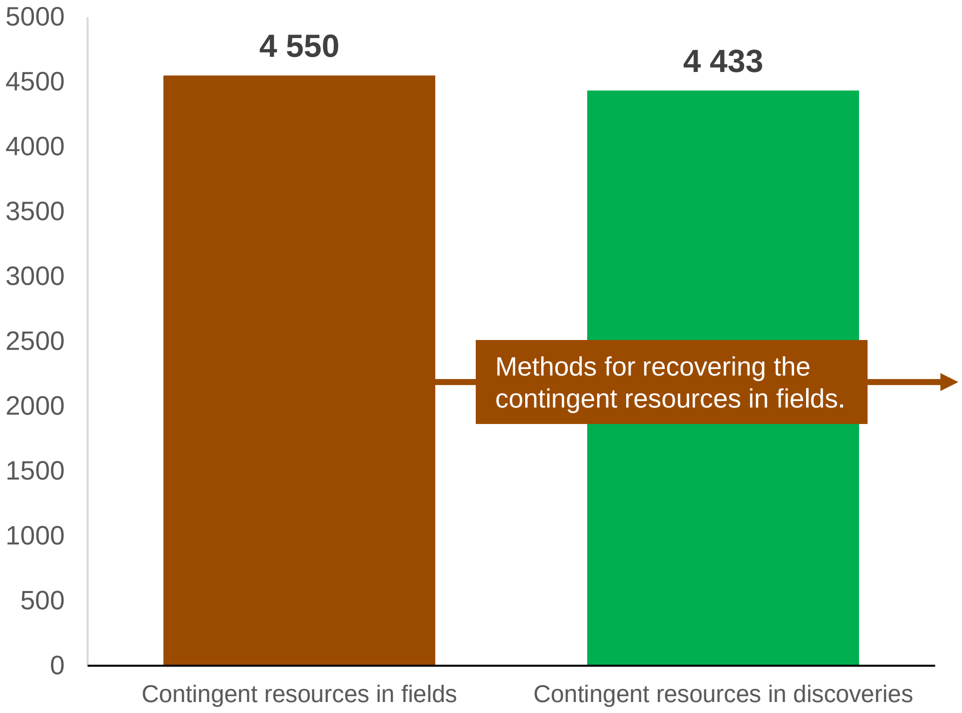
Possibility to add volumes rapidly also for offshore

	Different ways to add volumes	Lead time (Years)	Capex per well (MUSD)	Drilling emissions* (Tons CO2 per well)	Comment
Shale	Shale	0.5-1 years	~7 MUSD	~280	Shale has the possibility to add large volumes with short lead time, which has been observed in North America over the last decade. Drilling emissions are low and well capex is low.
Interventions	Dry interventions	2-9 months	*Likely below shale*	Varying, but limited	Dry interventions have short lead time, but limited resource potential. It is frequently used to add volumes on existing fields offshore at low cost.
	Wet interventions	9m-1.5y	*Likely slightly above shale*	~2100	Wet interventions have relatively short lead time, but higher drilling emissions and higher cost than the above.
Infill	Infill wells drilled with platform unit	5m-1.5y	*Likely similar to shale*	~1000	Drilling unit on the platform gives opportunity to drill new infill wells with short lead time, at low cost and with low emissions.
	Subsea slot recovery	1-2y		~2450	Subsea slot recoveries are more expensive than the above, but can compete on lead time with infill wells drilled with offshore rigs and are likely to be cheaper and with lower emissions.
	Infill wells drilled with offshore rigs	1-2y		~3500	Infill wells drilled with offshore rigs is a low-cost measure to add resources to existing hubs, but is more costly than the above infill and interention options. Also likely to have higher emissions.
New developments	Subsea tie-backs or wellhead platforms	2-3y		~3500	Subsea tie-backs can be used to prolongue the lifetime of existing hubs by tieing in new discoveries at proximity improving overall emission intensity.
	Fixed	3-5y		~2300	Assumed to be drilled with jackups, the drilling emissions are lower than for floater developments which are assumed to be drilled by floaters. Cost and lead time is longer than all the above, but resource potential is larger.
	Floaters	Redeployment ~2 years Standardized FPSO ~4 years Custom floater 3-6 years 2-6y	30-50 MUSD	~4650	Stand-alone developments requiring new design and commissioning have longer lead time than all the above, but are the only measure except shale unlocking very lage resources.

*Average drilling time is used to derive drilling emissions. Average emissions of jackups and floaters used for subsea tie-backs and infill wells, while jackups assumed for fixed developments and floaters assumed for floater stand-alone developments due to nature of depth. Source: Rystad Energy research and analysis

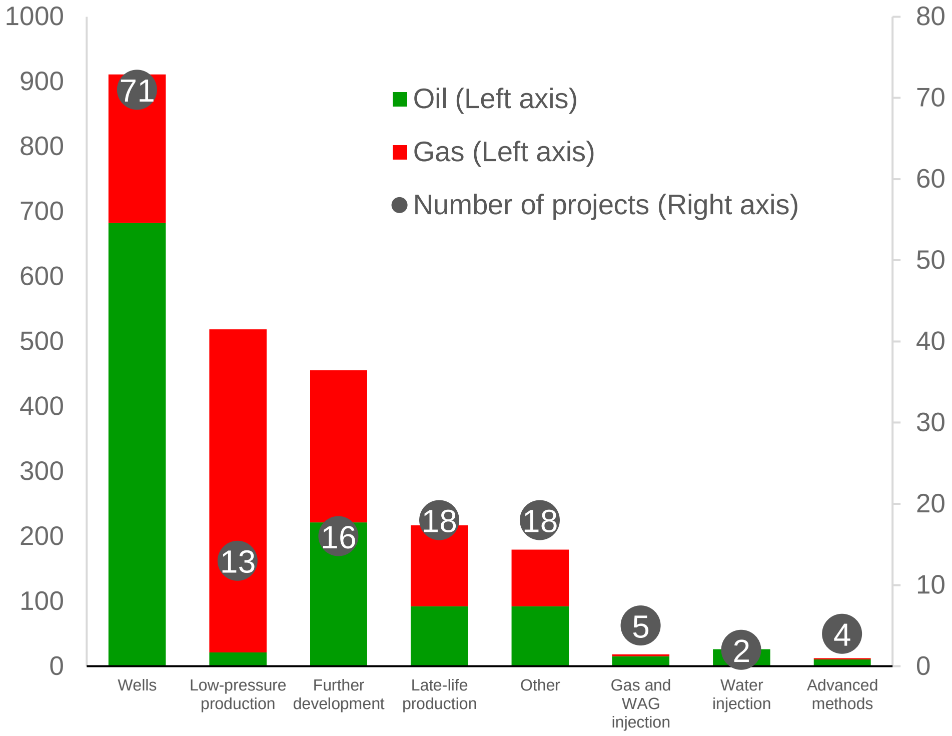
Emission dilemma when deciding on methods for improving recovery from fields

NPD contingent resources as of 31. December 2020
Million boe



Methods for recovering the contingent resources in fields.

Specific* projects for improving recovery from fields
Million boe



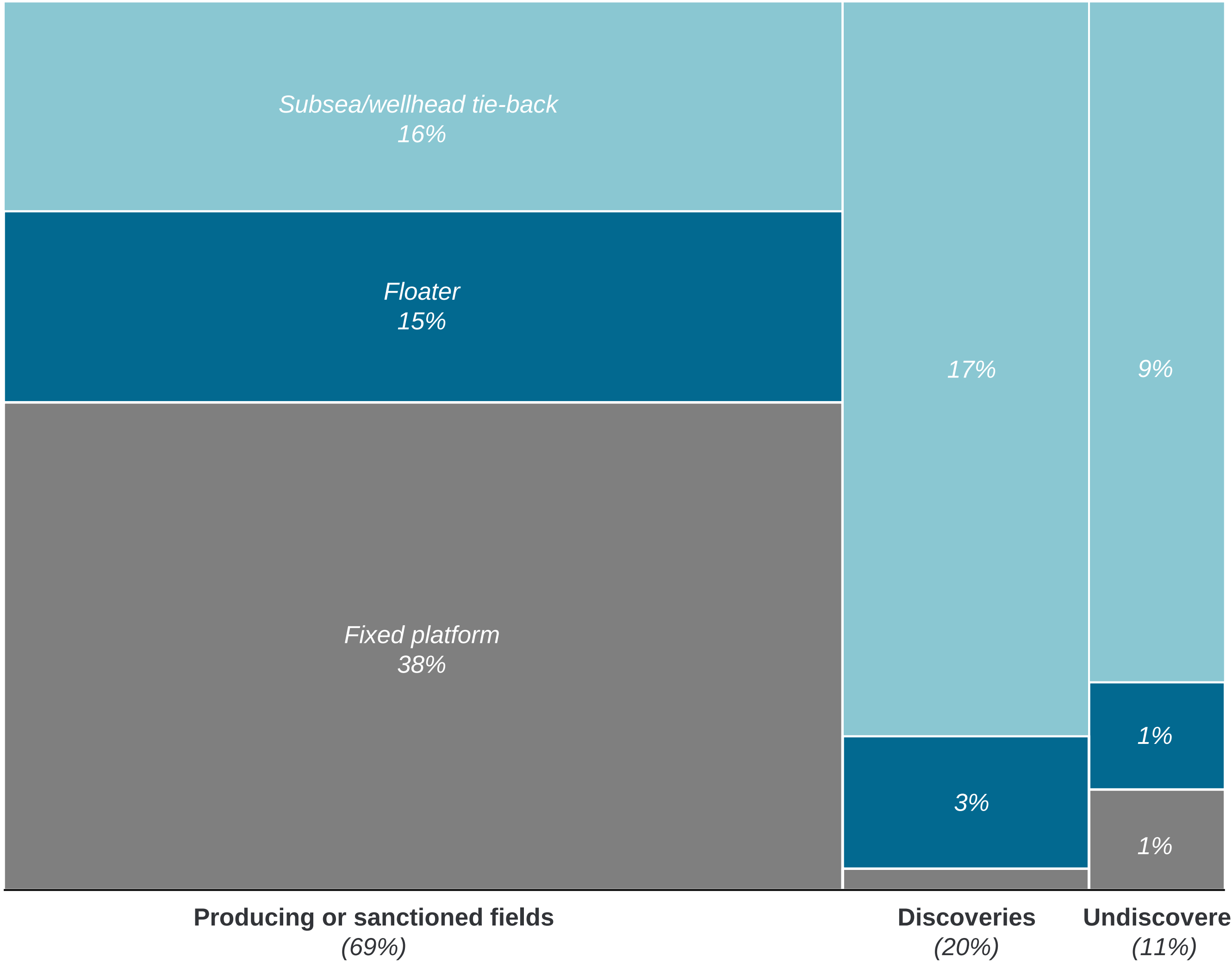
- The chart to the left above outlines NPDs accounts of contingent resources – resources that have been identified but are yet to be sanctioned. Current identified volume potential in fields is larger than in the combined portfolio of discoveries, highlighting how technologies that increases recovery in existing fields will have a large impact.
- The chart to the right highlights specific but undecided projects for improving recovery from fields, that is, methods for recovering the resource potential shown in the brown bar.
- When prioritizing future volumes, emissions could have an increasing impact as IOR is emission intensive. Creating a dilemma between “squeezing the lemon” and CO2 emissions.

*Specific but undecided. Source: NPD; Rystad Energy research and analysis

Almost 70% of 2021-2050 volume potential lie in sanctioned fields

Volume buckets on NCS between 2021-2050

Percentage of expected barrels of oil equivalents produced

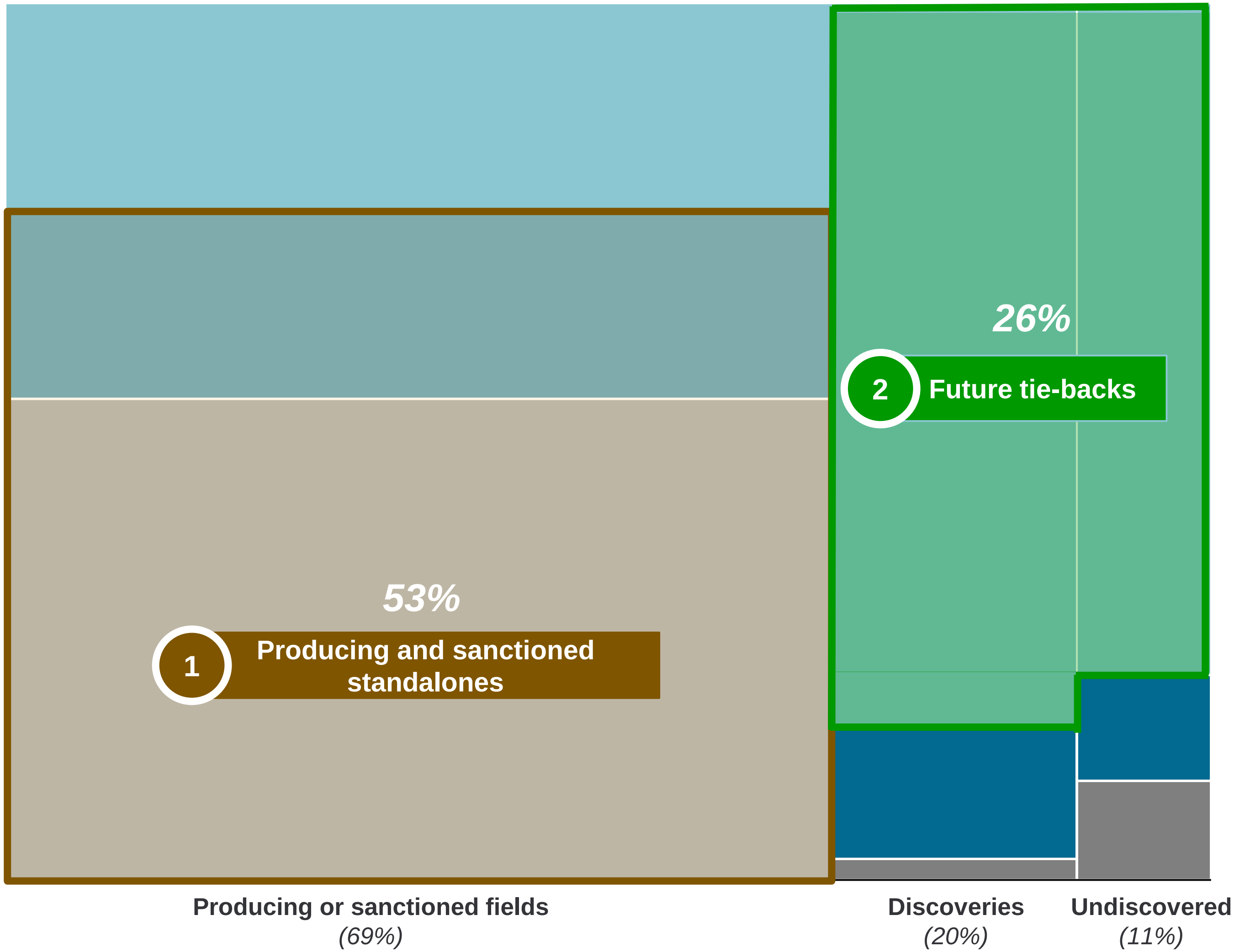


- The chart to the left outlines production volumes on the NCS in the period 2021-2050, in terms of current status of the field and facility type.
- The majority of the production volume potential lie in already sanctioned or producing fields, with a majority of these being fixed platforms.
- Future volumes, However, are expected to rely heavily on tie-back solutions, highlighting the potential in optimizing cost and emissions related to this category.

Source: Rystad Energy UCube

About one fourth of future production is expected from future tie-backs

Volume buckets on NCS between 2021-2050
Percentage of expected barrels of oil equivalents produced



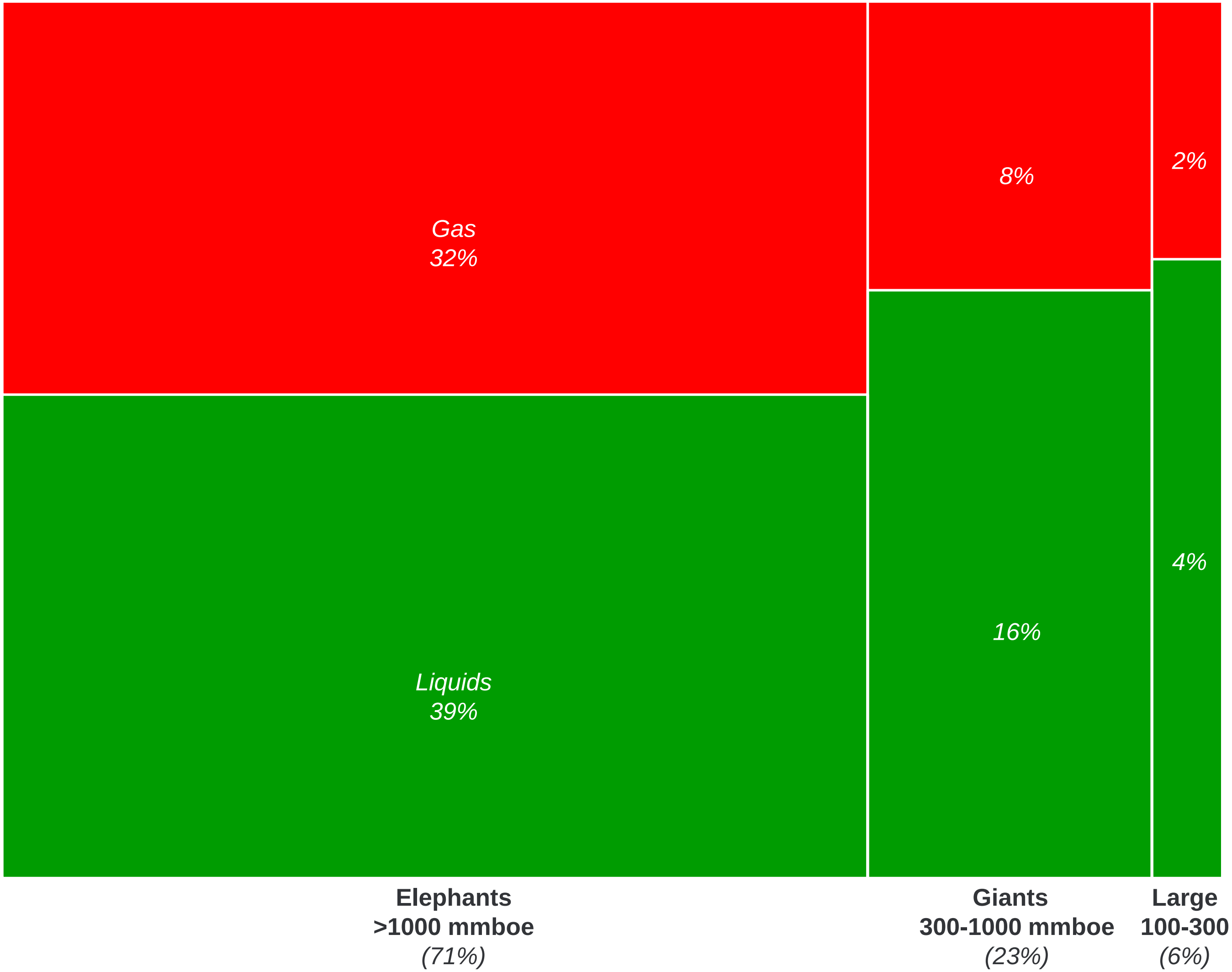
- Two large key buckets of future production volumes can be defined based on the categories on the previous page; 1) Producing and sanctioned standalones and 2) Future tie-backs.
- The producing and sanctioned standalones consists of volumes already sanctioned as standalone developments with dedicated processing facilities. Technologies that improve recovery in already developed fields will have a large impact on this bucket.
- The future tie-back bucket consists of volumes from fields expected to be developed as subsea/wellhead tie-backs. Technology that enable successful exploration and resource effective development will be important for these volumes.

Source: Rystad Energy UCube

Large potential for IOR/EOR in producing and sanctioned elephant fie

1 **Producing and sanctioned standalones**

Volume buckets from sanctioned standalone fields on the NCS between 2021-2050
Percentage of expected barrels of oil equivalents produced

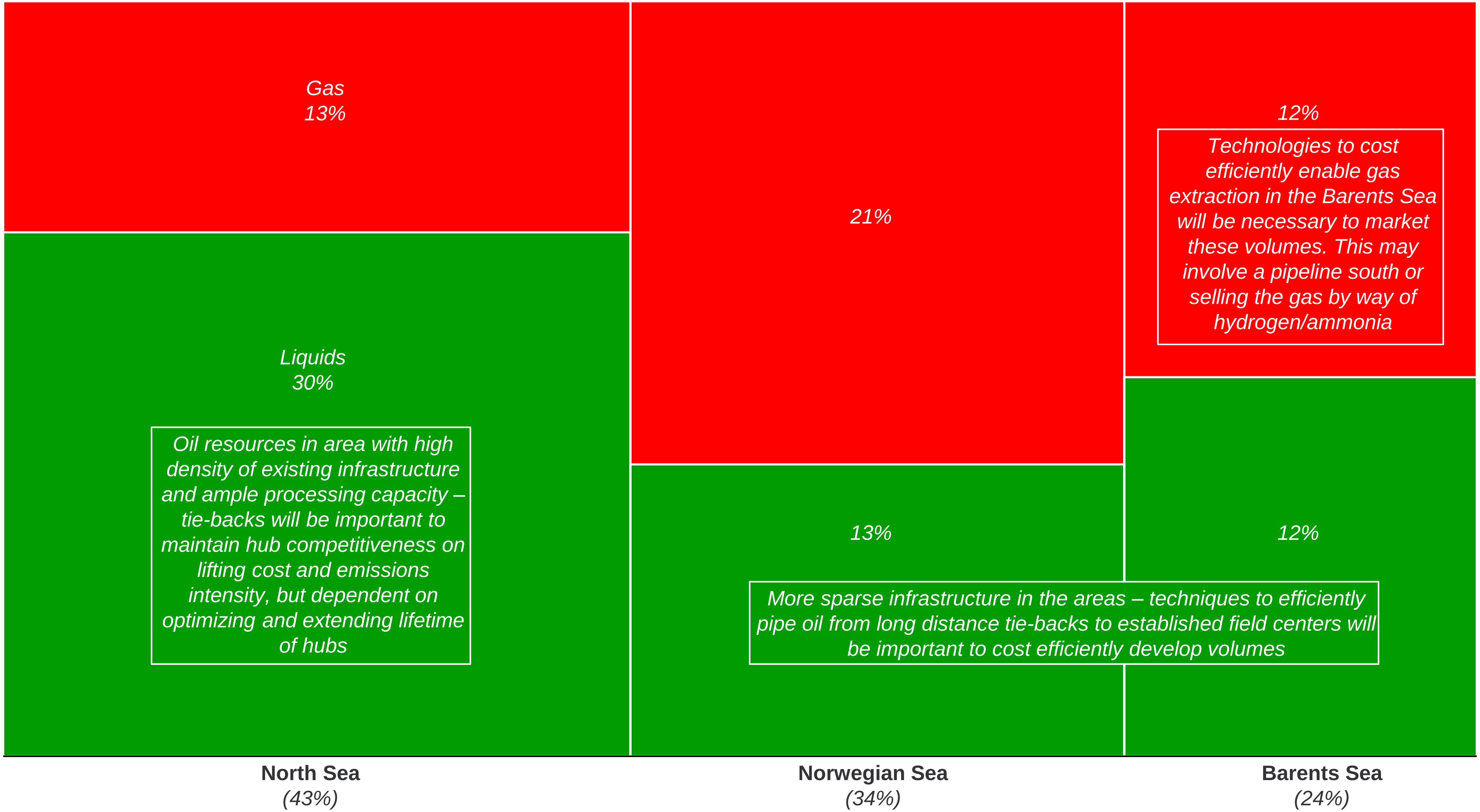


- The chart outlines production volumes from already producing and sanctioned standalone fields on the NCS in the period 2021-2050.
- The majority of this production comes from fields classified as Elephants, and the potential for increased reserves is large if technologies just slightly improves recovery rates in these fields are adapted.
- Currently, IOR/EOR* measures mainly target liquids. However, there has been an increased focus on recovery rates for gas in recent years. As the chart shows, there are substantial gas reserves in large producing or sanctioned fields. There is thus a large potential for technologies that targets increased gas recovery.

*Improved/enchanted oil recovery. Source: Rystad Energy UCube

Tech could focus on increased oil recovery, flow assurance or gas evacuation

Volume buckets from unsanctioned tie-back fields on the NCS between 2021-2050
Percentage of expected barrels of oil equivalents produced



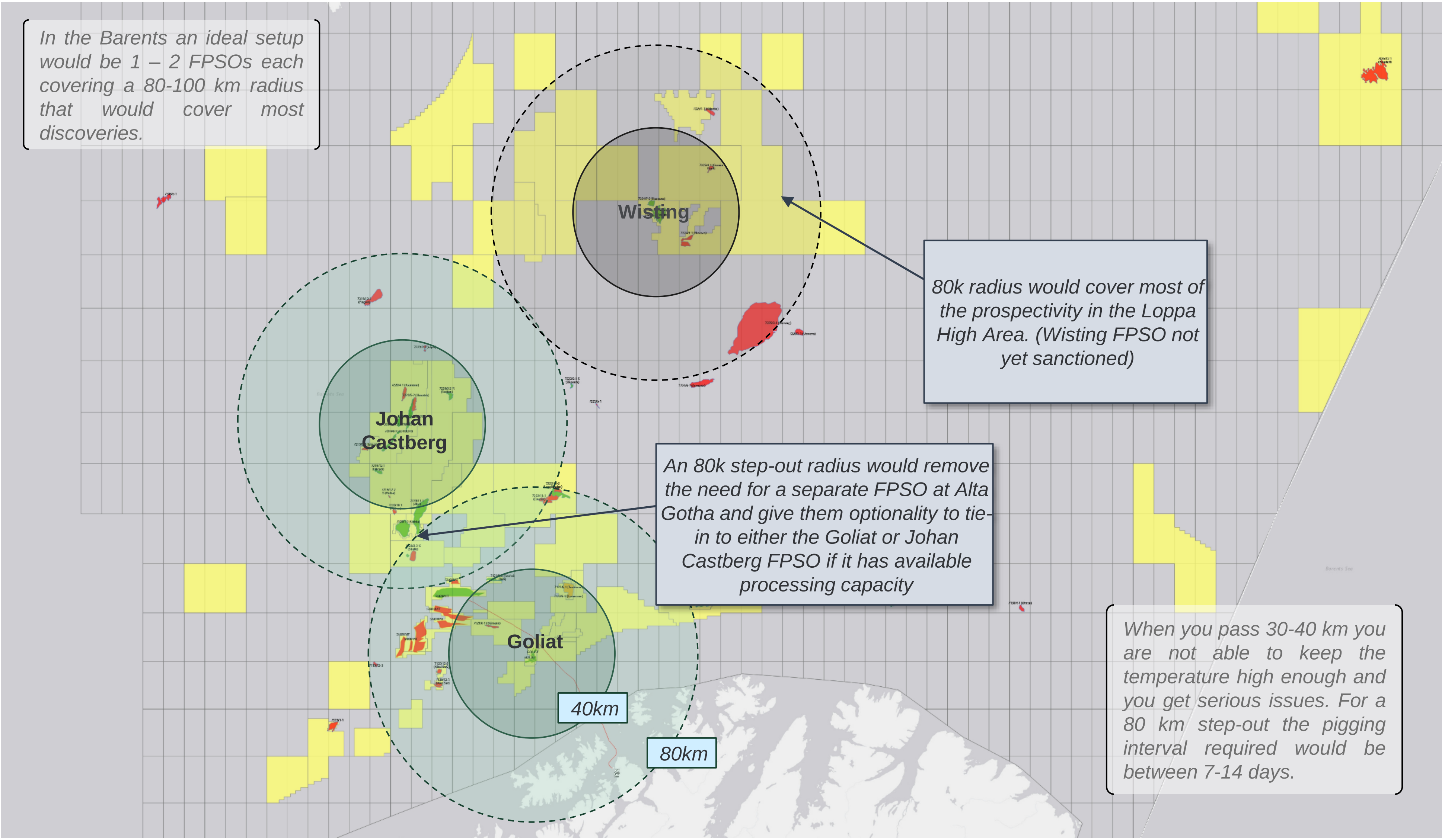
Oil resources in area with high density of existing infrastructure and ample processing capacity – tie-backs will be important to maintain hub competitiveness on lifting cost and emissions intensity, but dependent on optimizing and extending lifetime of hubs

More sparse infrastructure in the areas – techniques to efficiently pipe oil from long distance tie-backs to established field centers will be important to cost efficiently develop volumes

Technologies to cost efficiently enable gas extraction in the Barents Sea will be necessary to market these volumes. This may involve a pipeline south or selling the gas by way of hydrogen/ammonia

Source: Rystad Energy UCube

A key issue is to unlock volumes out of range of existing infrastructure



In the Barents an ideal setup would be 1 – 2 FPSOs each covering a 80-100 km radius that would cover most discoveries.

80k radius would cover most of the prospectivity in the Loppa High Area. (Wisting FPSO not yet sanctioned)

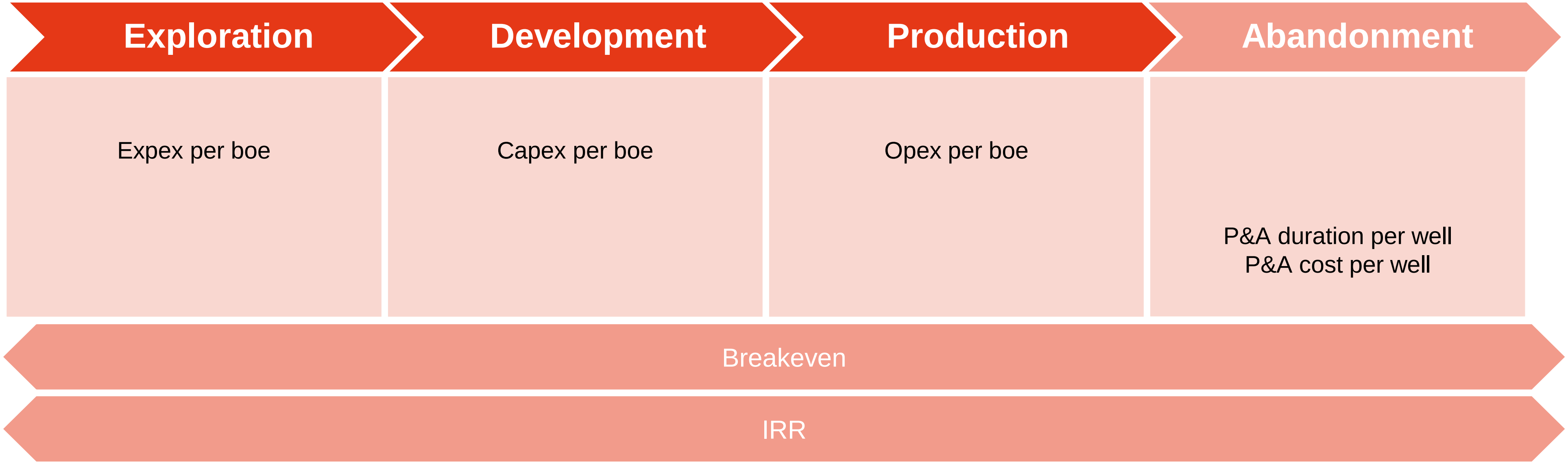
An 80k step-out radius would remove the need for a separate FPSO at Alta Gotha and give them optionality to tie-in to either the Goliat or Johan Castberg FPSO if it has available processing capacity

When you pass 30-40 km you are not able to keep the temperature high enough and you get serious issues. For a 80 km step-out the pigging interval required would be between 7-14 days.

Source: Rystad Energy UCube

Report contents

Cost dimension: Chapter synopsis



Exploration

Expex per boe

Development

Capex per boe

Production

Opex per boe

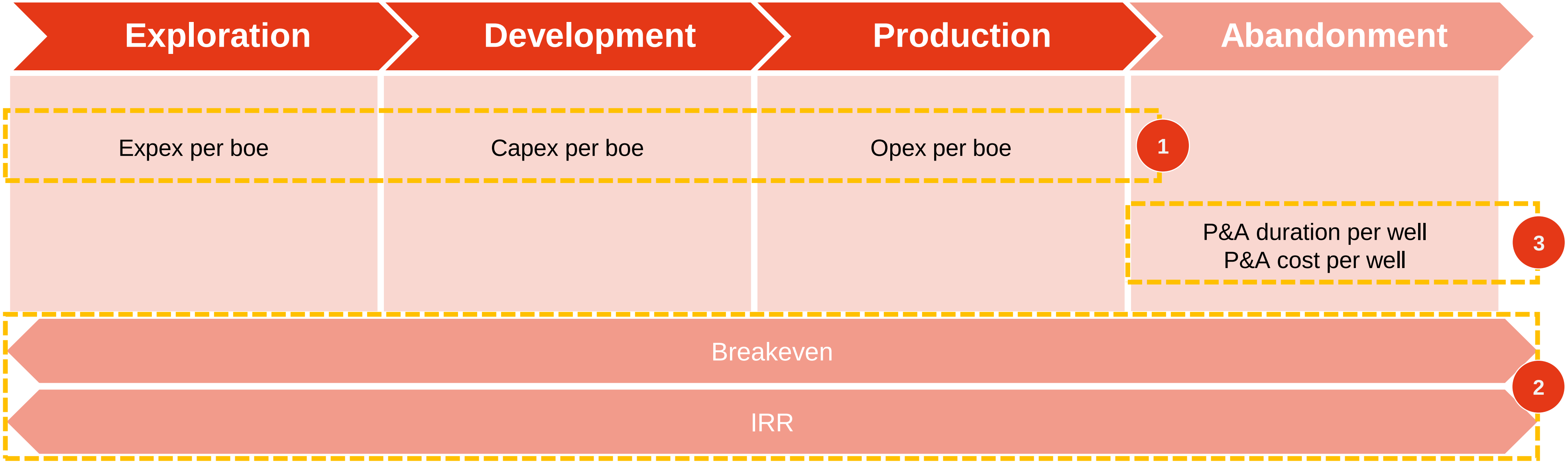
Abandonment

P&A duration per well
P&A cost per well

Breakeven

IRR

Cost dimension: Chapter synopsis



Exploration

Development

Production

Abandonment

Expex per boe

Capex per boe

Opex per boe

1

P&A duration per well
P&A cost per well

3

Breakeven

IRR

2

Chapter synopsis

1

At a first sight, exploration and greenfield developments on the NCS look expensive. It is important to take into account the beneficial exploration refund schemes and tax regime incentivizing investments. Temporary tax regime includes direct expensing of investments and uplift of special tax to 24%. Operational costs are very competitive due to efficient hubs, which makes the NCS very competitive overall.

2

The NCS is highly competitive on an overall cost basis, with a breakeven of 26 USD/boe and an IRR of 30% on average for sanctioned projects in 2019 and 2020.

3

P&A is expensive on the NCS looking at historical numbers. The reasons are high average complexity of wells, deep waters and strict regulations.

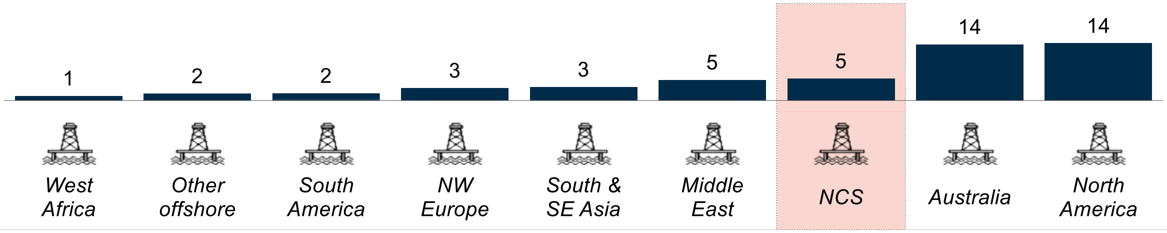
NCS remains competitive due to beneficial tax regime, despite high expex and greenfield capex per boe

1

Key indicators for competitiveness

Comment

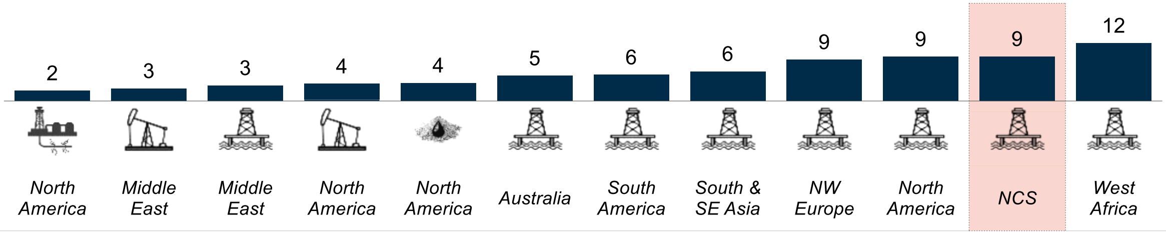
Expex per boe discovered* (USD/boe)



* Exploration expenses per found resources. Only offshore. Includes only commercial discoveries where public information is available. Average of 2019 and 2020.

537 mmboe of commercial resources were discovered on the NCS in 2020. This despite the cuts in exploration budgets seen due to COVID-19. Most NCS players reported 20-30% cuts in planned exploration budgets due to COVID-19. The combined effects lead to an expex per commercial discovered resources of 4 USD/boe in 2020, which is a decrease from around 6 USD/boe in 2019 and 8 USD/boe in 2018.

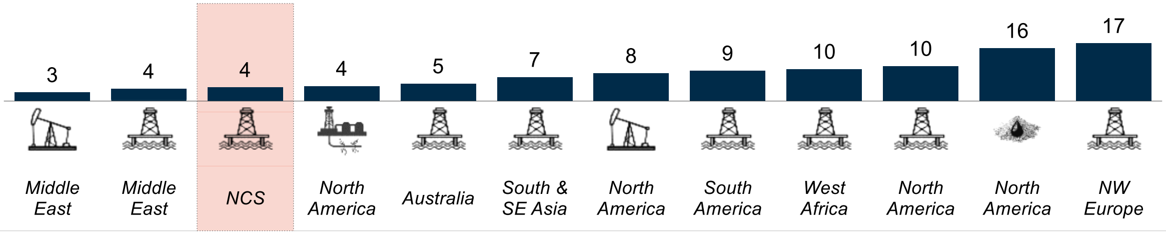
Capex per boe* (USD/boe)



*Greenfield capital expenditures related to sanctioned oil and gas fields in current year for these fields. Volume weighted average of 2019 and 2020.

Greenfield capital expenditures per sanctioned volumes still remain high on the NCS, but it is important to consider beneficial tax regime and . Cost levels have remained stable since 2018, after a massive reduction in capex from 2014 to 2018.

Opex per boe (USD/boe)**



**Excludes transportation and tax opex.Includes only opex associated with the production of hydrocarbons in addition to SG&A.

Operational expenditures per volume produced are in general down in almost all regions since 2018. This is driven by local currency depreciations VS US dollars through 2020 and large budget cuts due to COVID-19. This can especially be observed in Brazil where Petrobras has cut 22% in employee count and Brazilian real have seen a 55% currency depreciation since 2019.

- NCS looks to be an expensive region in terms of exploration and development but considering the beneficial tax regime and exploration refund schemes, the NCS overall is more beneficial than how it looks here.
- The NCS is highly competitive on operational costs. Local markets have seen a considerable reduction in operational costs due to depreciation of local currencies VS USD – since operational costs often are paid in local currencies.

Source: Rystad Energy UCube

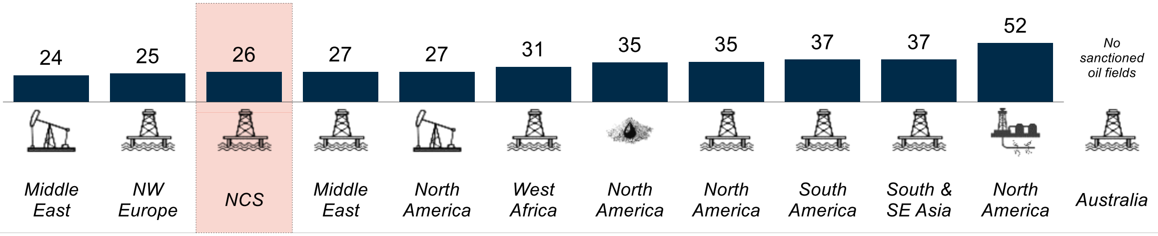
Offshore · *Shale unconventional* · *Onshore conventional* · *Oil sands unconventional*

NCS is competitive on breakeven, only beaten by Middle East onshore and UKCS

Key indicators for competitiveness

Comment

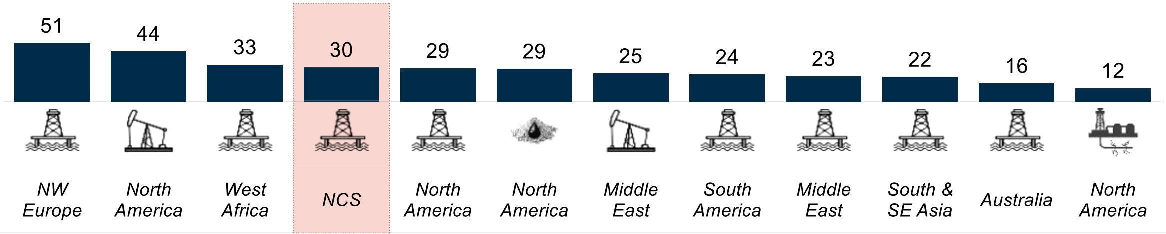
Breakeven oil price*** (USD/boe)



Oil fields sanctioned on the NCS in 2019 were Johan Sverdrup ph. 2, Solveig and Tor II, while in 2020 only Hod redevelopment and Balder Future were sanctioned. JS ph. 2 has a positive impact on the average with a BE well below 25 USD/boe according to Equinor. The low BE in the Middle East is driven by a couple of large expansion projects sanctioned in 2019 like Berri and Marjan.

****Breakeven price for oil fields approved in 2018 seen from the approval year – oil price that returns NPV equal to zero at 10% discount rate. Weighted average of 2019 and 2020.*

IRR****



Assuming an oil price forecast of 50 USD/boe flat, the IRR on the NCS is expected at 30% for fields sanctioned in 2019 and 2020. This is mainly due to Johan Sverdrup phase 2. Only the subsea tie-back Abigail was sanctioned on the UKCS in 2020, while Seagull and Storr - also with low BEs were sanctioned in 2019.

****Breakeven price for oil fields approved in 2019 and 2020 seen from the approval year – oil price that returns NPV equal to zero at 10% discount rate. Oil price forecasted at 50 USD/boe flat. Weighted average of 2019 and 2020.*

- The NCS is highly competitive on breakeven on oil fields since 2018. Johan Sverdrup phase 2, Solveig and Tor II were sanctioned in 2019, while Hod redevelopment and Balder Future were sanctioned in 2020.
- Johan Sverdrup phase 2 sanctioned in 2019 has a positive impact on the overall level with a breakeven below 25 USD/boe.
- On the UKCS, sanctioning of Seagull, Storr and Abigail ensured a low average breakeven and good internal rate of return.
- The Middle East offshore sanctioned a couple of very large expansion projects over the two last years, including Berri and Marjan, which positively impacted the average breakeven. ME onshore conventional mostly included Iranian projects in 2020 – which are expected to have low breakevens based on historic levels.

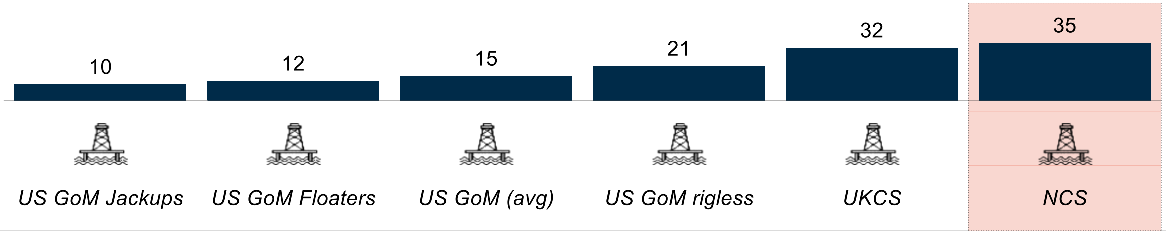
Source: Rystad Energy UCube

P&A cost higher in deepwater and harsh offshore regions

Key indicators for competitiveness

Comment

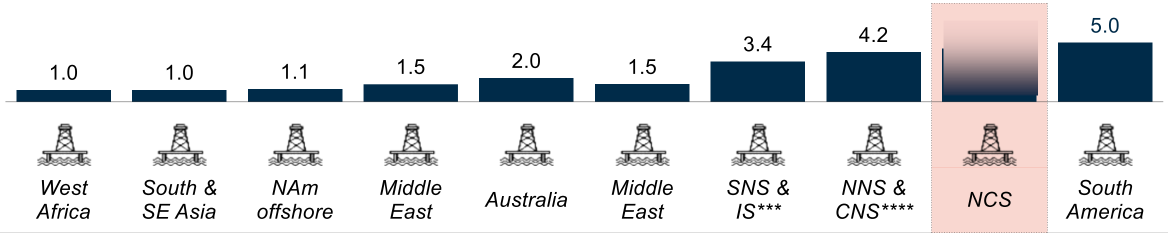
P&A duration per well*



Historical benchmarks of duration of P&A work per well in the United States Gulf of Mexico, NCS and UKCS. The NCS historically has the longest duration. This is likely due to more demanding regulations in terms of plugging and the nature of deepwater and harsh environment which increases average complexity of wells.

*Historical average P&A duration per well depending on region and rig type/intervention unit.

P&A cost per well (MUSD)**



Estimated P&A cost per well per region in the period 2019-2023 indicates deepwater and harsh offshore regions increases P&A cost. The number of observations in Norway over the last years have been limited, and as such the average cost benchmark is unknown. However, NCS is likely to be comparable to NNS & CNS in UKCS, as conditions are a lot the same.

***Estimated P&A cost per well for offshore regions based on expected activity from 2019-2023. ***Southern North Sea and Irish Sea (UKCS). ****Northern & Central North Sea (UKCS).*

- With an increasing demand for P&A work in the years and decades to come, as more fields on the NCS will shut down, new technologies decreasing cost of P&A are more than welcome.
- NCS is a high-cost region with high average complexity of wells – both driven by regulations, deep waters and harsh environment.
- The UKCS is more mature than the NCS and have seen an increase in P&A and decommissioning activity over the last decade. The Northern and Central North Sea are likely to be good benchmarks of the P&A costs on the NCS, as the water depth, environment and structures are comparable.

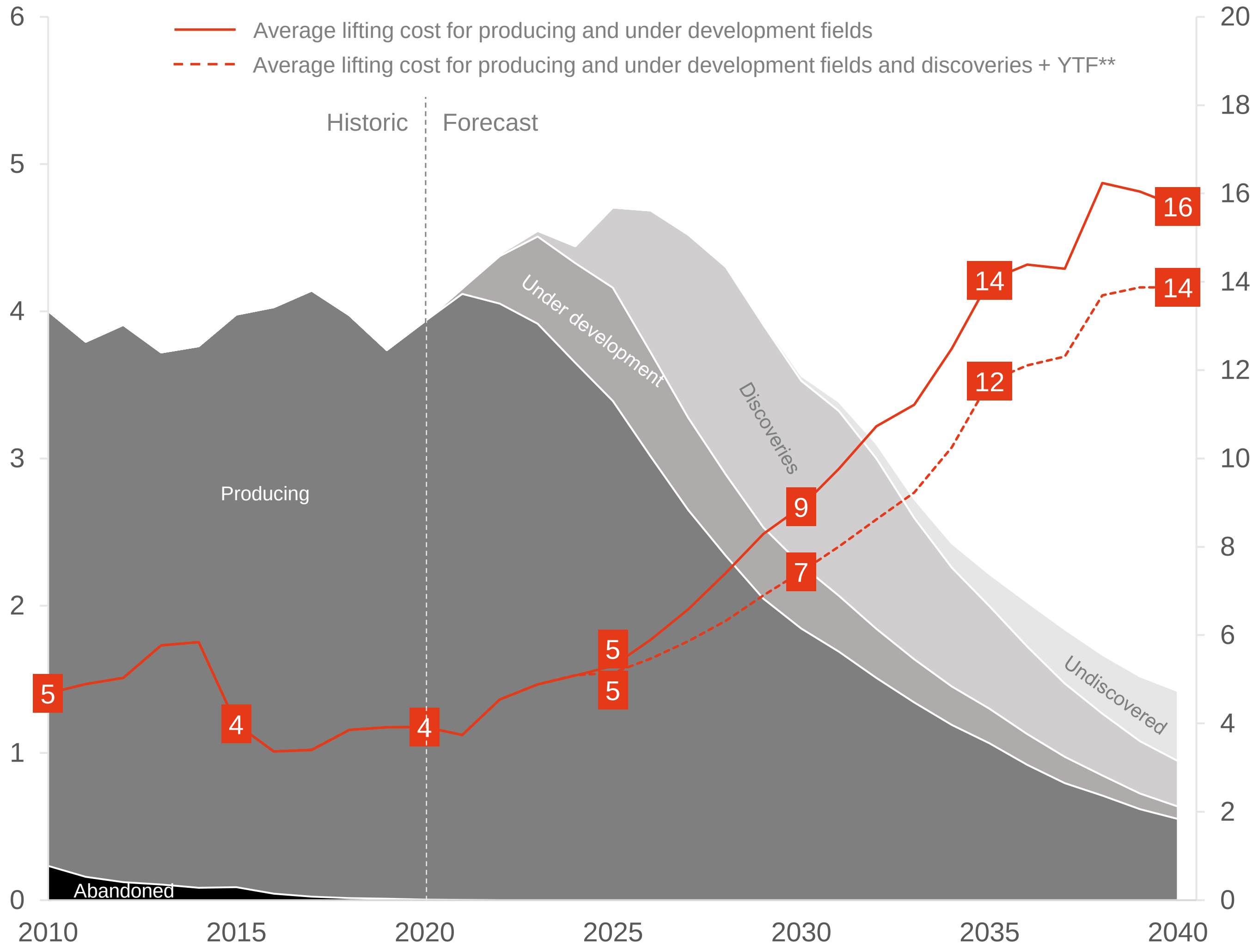
Source: Rystad Energy UCube

Offshore *Shale unconventional* *Onshore conventional* *Oil sands unconventional*

With NCS production in decline, lifting cost increases unless measures are taken

Production on the NCS by lifecycle
Mmboe/d

Average lifting cost for NCS
Opex per boe produced*

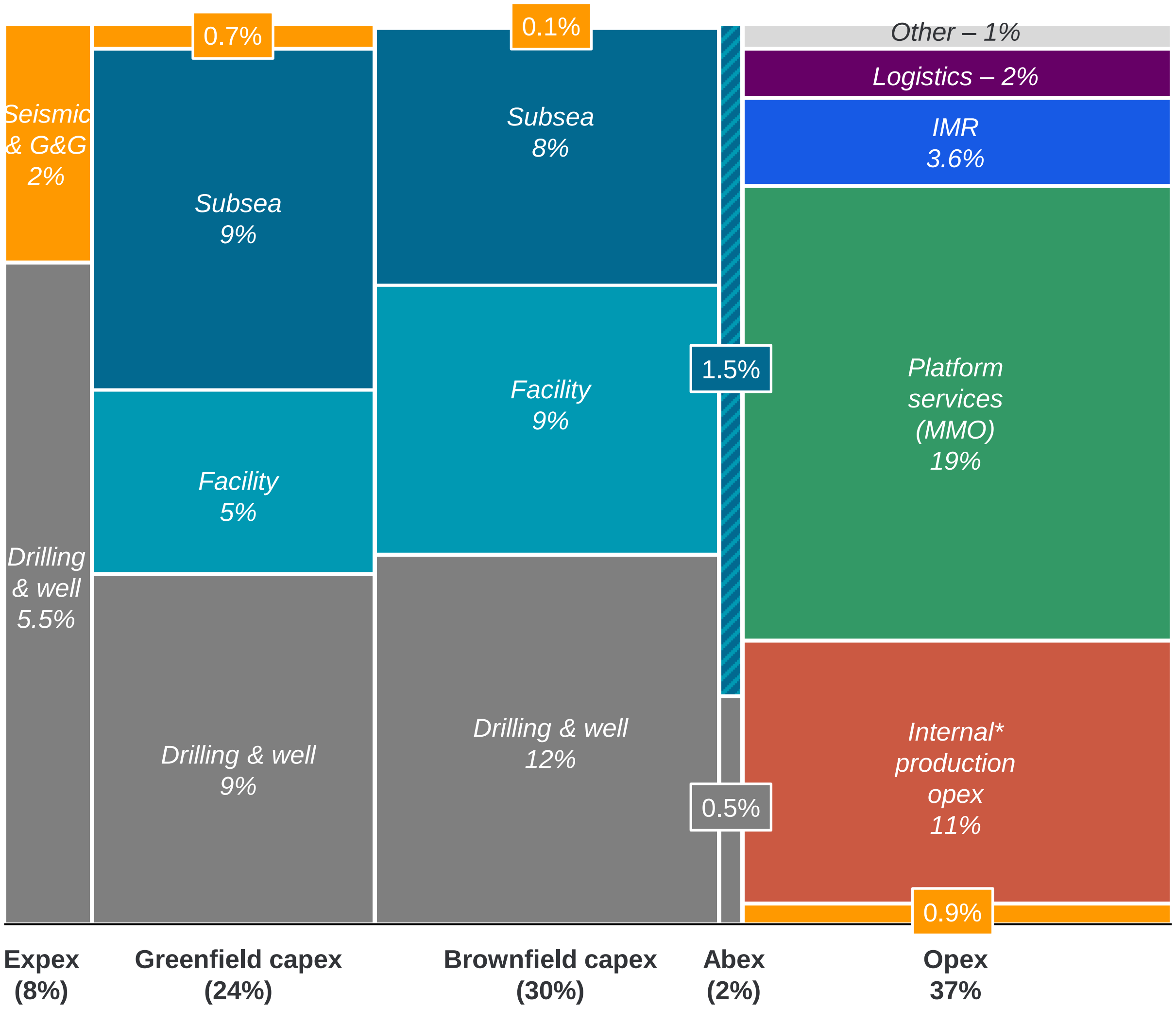


- The chart show the average lifting cost on the NCS historically and expected levels going forward.
- As the shelf matures and production decline, the lifting cost per barrel will increase. This applies especially to producing fields.
- In 2030 the lifting cost per boe is expected to have gone from below 4 to 10 USD/boe on average for currently producing fields. Some will be even higher. In 2030 production from currently producing fields account for 50% of the expected output from NCS.
- This will pose a challenge to the competitiveness of the NCS compared to younger basins as we see for the UKCS today.

*Production opex only. SG&A and transportation tariffs not included; **only from opened areas
Source: Rystad Energy UCube

Capex is 60% of the spend, drilling and well the largest spend group

Spend buckets on the NCS spend 2021-2040
Percentage of spending in MUSD real 2021



Source: UCube, ServiceDemandCube

Four main spend buckets identified

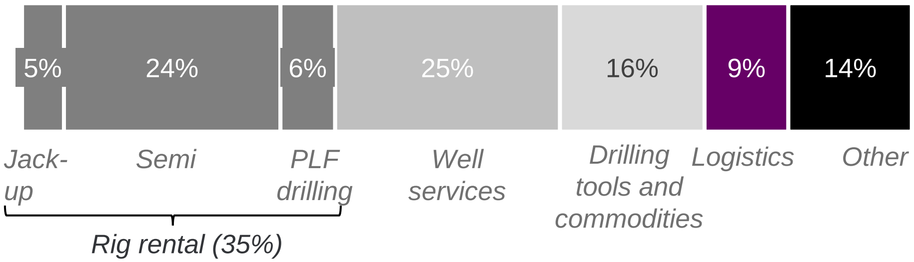
1. Drilling & well (28%)
2. Facility capex (14%)
3. Platform service and maintenance (19%)
4. Subsea capex (18%)

- Other take aways:
- 66% of the spend will target fields that are producing
- Capex is 61% of the spend across exploration, greenfield and brownfield
- IMR is not significant
- Logistics is hidden in the other capex buckets (see next slide)

Deep-dive into cost components for the four spend buckets

Drilling & well

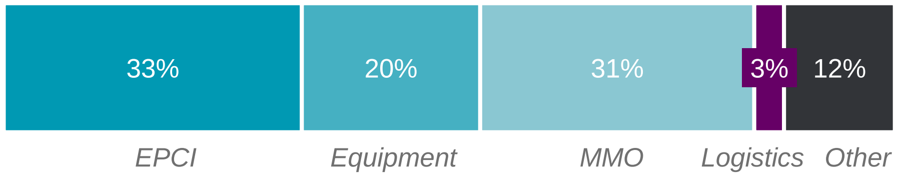
Drilling & well spend by component 2021-2040
Percentage



- Rigs are 35% of the total well cost, addressing time spent drilling is of high value.
- Three large associated buckets with well service, drilling tools and commodities and logistics. These are also highly time dependent.

Facility capex

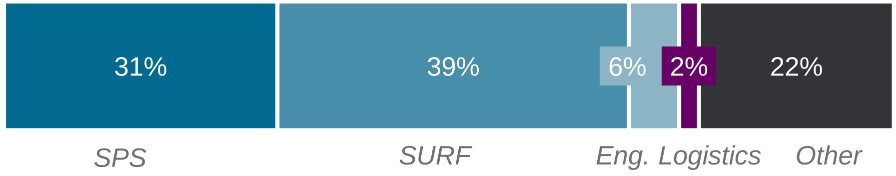
Facility capex by component 2021-2040
Percentage



- EPCI largest segment covering 33% and equipment it covers more than 20%.
- MMO capex including large brownfield topside modules is almost 1/3 of the market

Subsea capex

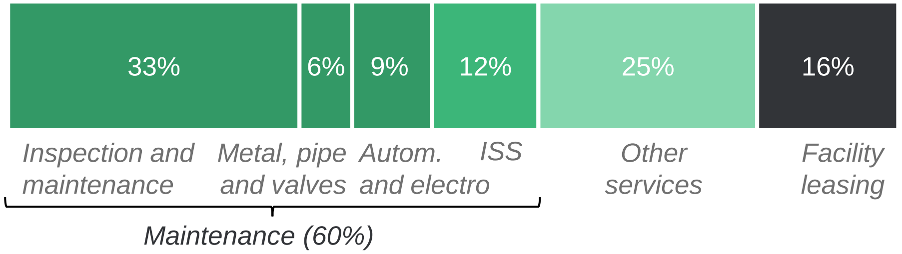
Subsea capex by component 2021-2040
Percentage



- Traditional contract scopes covers 70% of subsea capex. SURF most important as it includes installation.
- SPS system typically just below 1/3 of the project cost.

Platform services

Platform services by component 2021-2040
Percentage

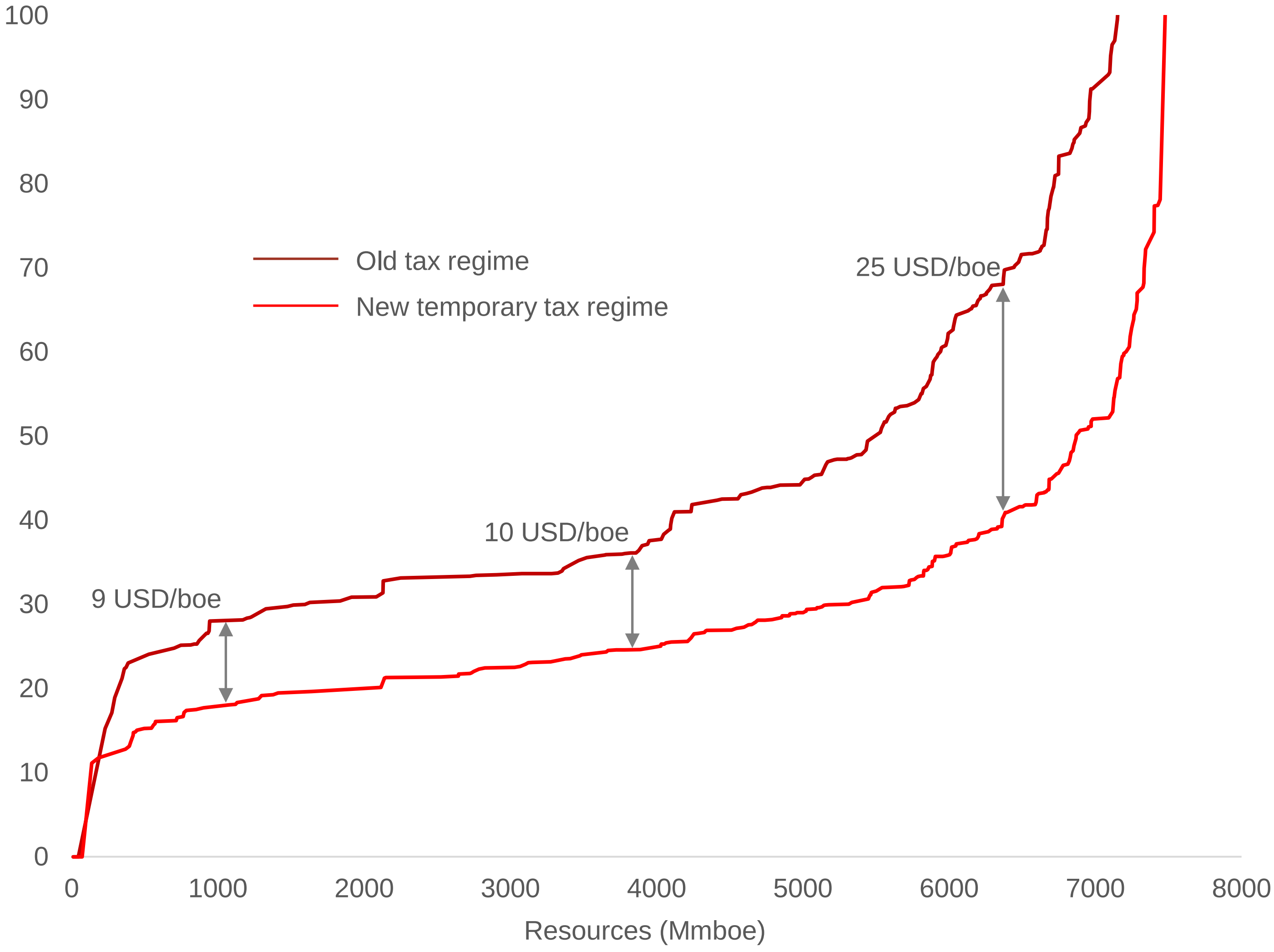


- The majority of platform services are labor intensive except for facility leasing (leased FPSOs), which makes up 12% of platform services on the NCS.
- Maintenance accounts for 50% of the spend, together with MMO capex, this bucket is substantial

Source: Rystad Energy UCube; ServiceDemandCube

New tax regime improves breakevens in order of magnitude 10 USD/bbl

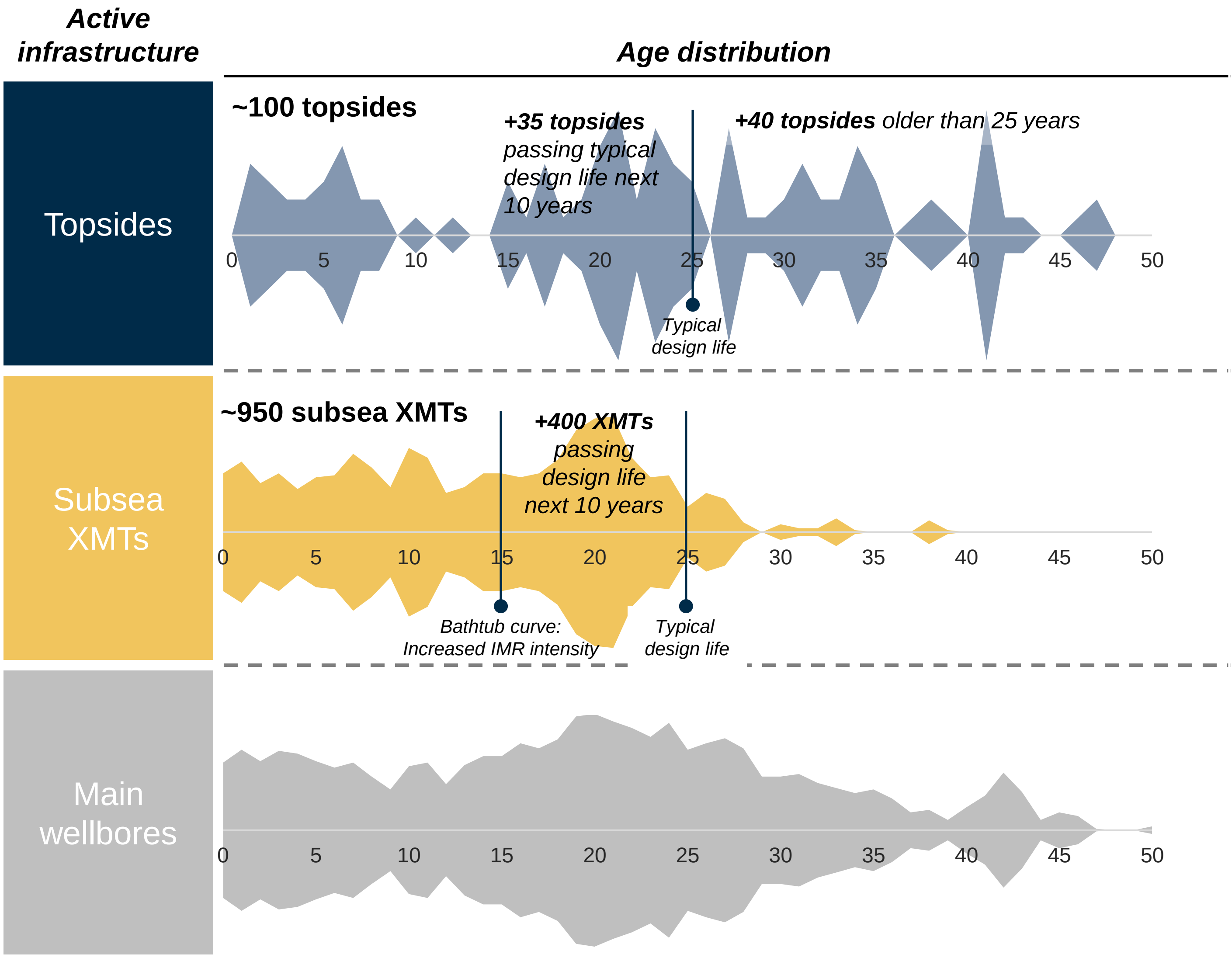
Cost-of-supply curve for resources in oil and gas discoveries by tax regime
USD/boe



Source: Rystad Energy research and analysis

- The chart illustrates breakeven prices for all Norwegian oil and gas discoveries under the old and new tax regime.
- The upper line is based on the old tax regime, while the lower line is based on the new tax regime approved in May 2020 in light of the COVID-19 situation.
- The new tax regime will have an increasing positive effect on breakeven prices with increased resource base and results in on average 40% lower breakeven prices.
- The new regime changes uplift of special tax from 20.8% over 4 years to 24% with direct expensing.
- Only pre-start-up investments made in accordance with PDO's delivered before end of 2022 and approved before end of 2023 are affected by the new tax regime.

An ageing NCS – Significant challenges for maintenance intensity and integrity



~100 topsides

+35 topsides *passing typical design life next 10 years*

+40 topsides *older than 25 years*

Typical design life

~950 subsea XMTs

+400 XMTs *passing design life next 10 years*

Bathtub curve: Increased IMR intensity

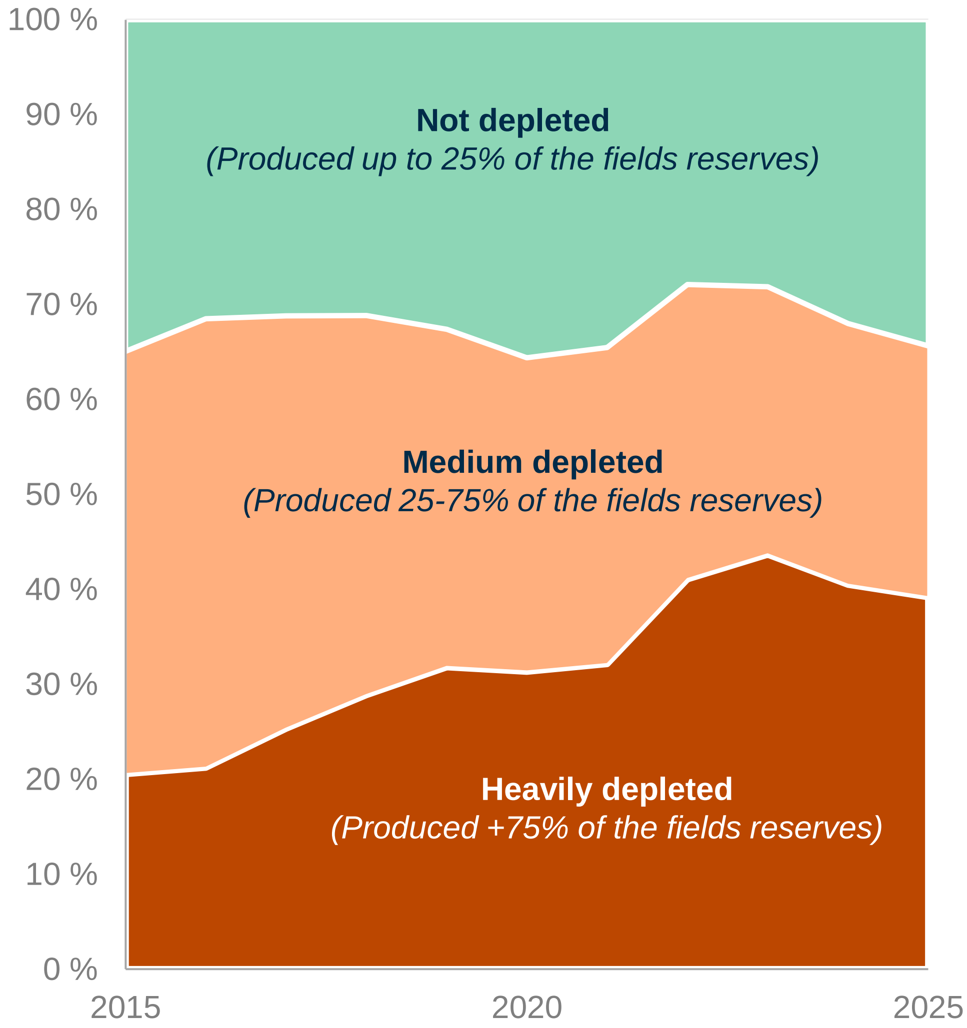
Typical design life

- Significant portions of the NCS infrastructure is passing its design life, pose challenges for maintenance intensity and integrity.
- Challenge to increase over the next 10-20 years. Large parts of this infrastructure will need to be upgraded or heavily maintained to ensure future integrity.
- For hosts there are a large share of topsides that have passed the 25 year mark and have already conducted lifetime extensions. Still, ensuring integrity is more challenging on upgraded facilities than new.
- For subsea infrastructure we observe significant uptick in IMR intensity once the age passes 15 years as a function of more failures and inspection needs.
- Large share of the topholes on the NCS, although potentially slot-recovered are centered around the 20-25 year mark.

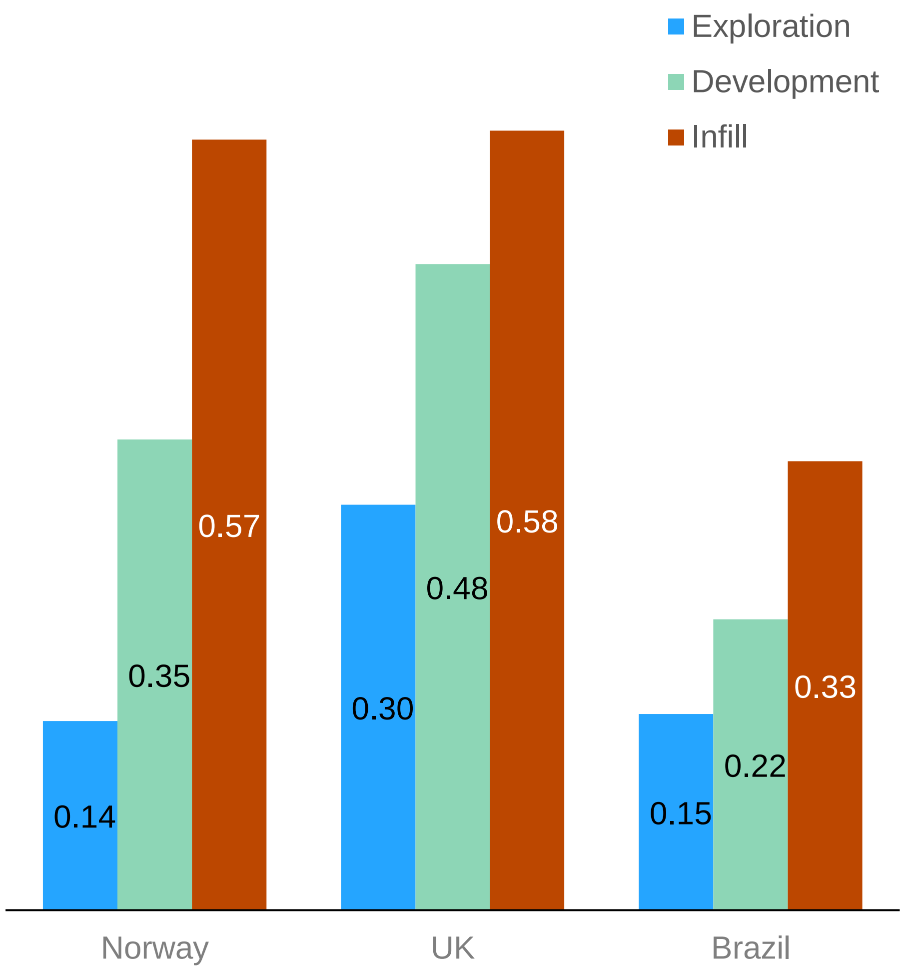
*Subsea XMT age based on age of main original wellbore - no replacements assumed only refurbishments
Source: NPD; Rystad Energy research and analysis

An increased brownfield focus yields additional drilling challenges that needs to be solved

Offshore wells by reservoir depletion
Share of wells drilled



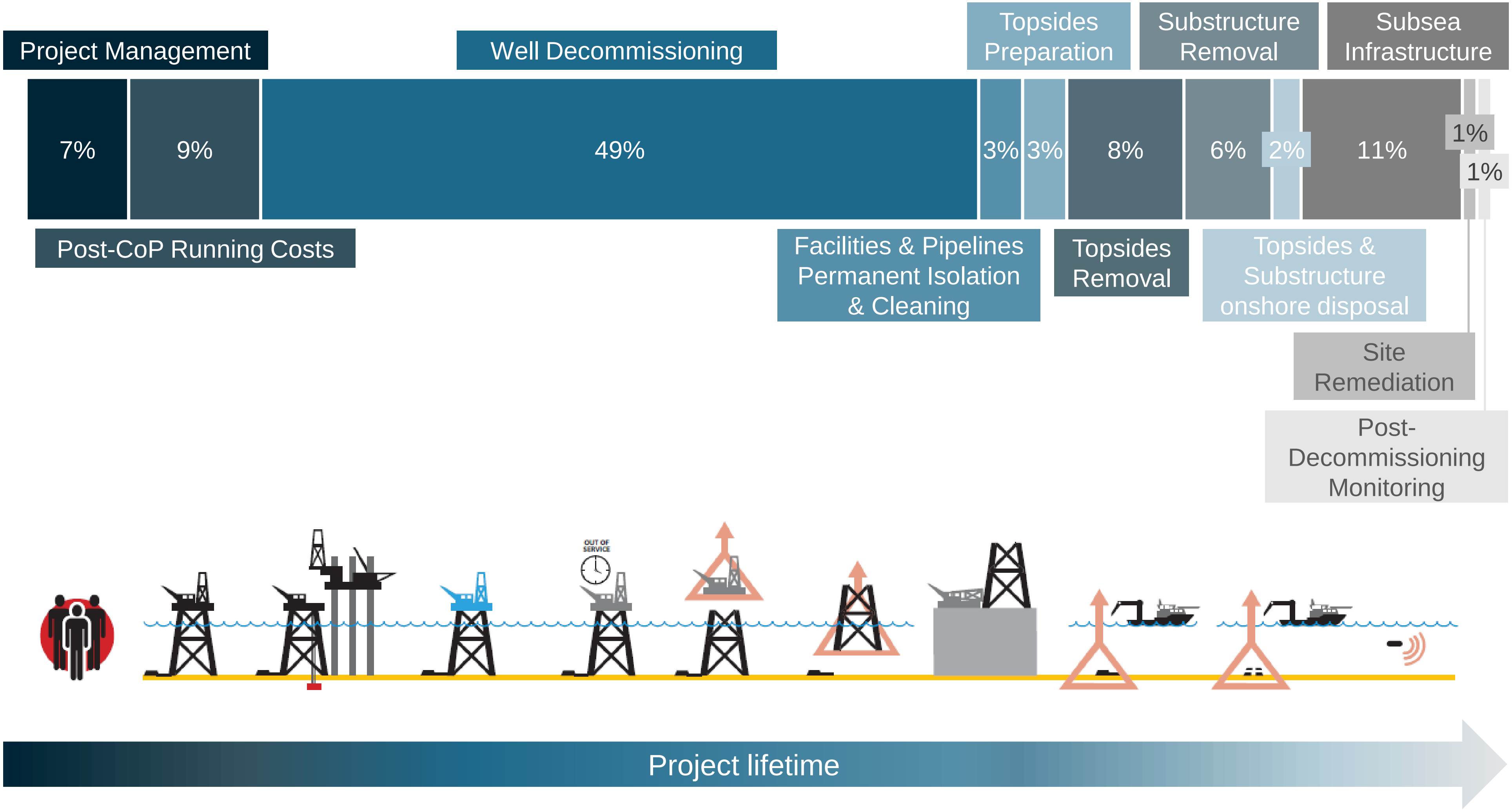
Likelihood for technical sidetracks (TST)
TST per well



Source: ANP; NPD; DECC; Rystad Energy UCube; Rystad Energy research and analysis

Well decommissioning forecasted to 49% of total decommissioning cost on UKCS

UKCS Decommissioning Work Breakdown Structure – Ten-Year Expenditure Forecast



Project Management

Well Decommissioning

Topsides Preparation

Substructure Removal

Subsea Infrastructure

Post-CoP Running Costs

Facilities & Pipelines Permanent Isolation & Cleaning

Topsides Removal

Topsides & Substructure onshore disposal

Site Remediation

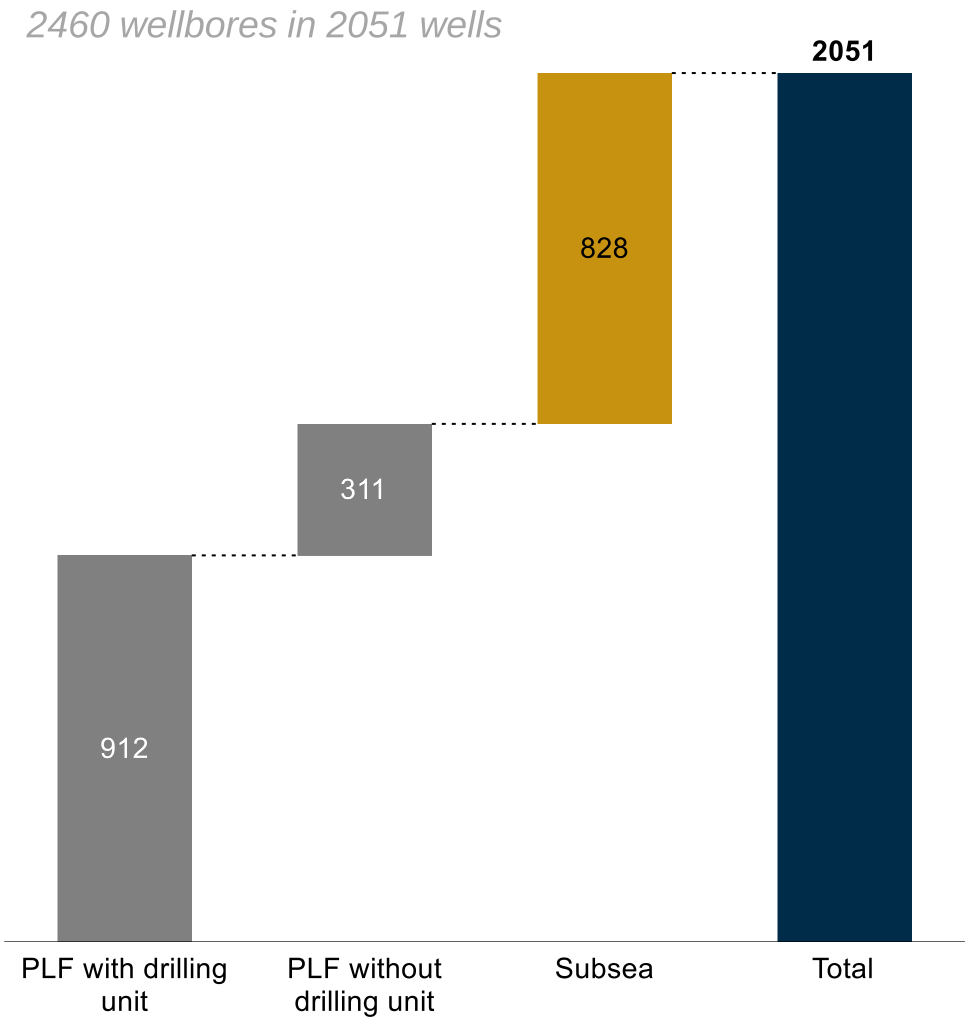
Post-Decommissioning Monitoring

Project lifetime

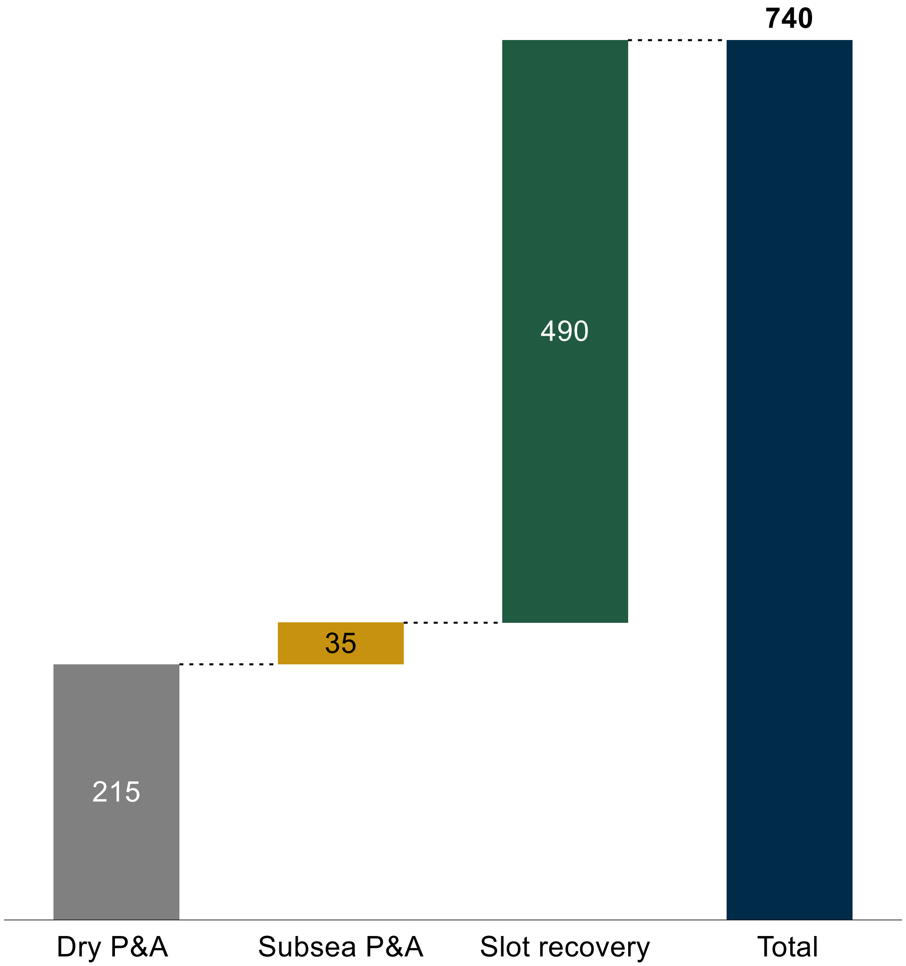
Source: UK Oil & Gas Decommissioning Insight 2020

Large P&A scope the next 5 years when including slot recoveries

Current active NCS well inventory 11.03.2021
Number of wells



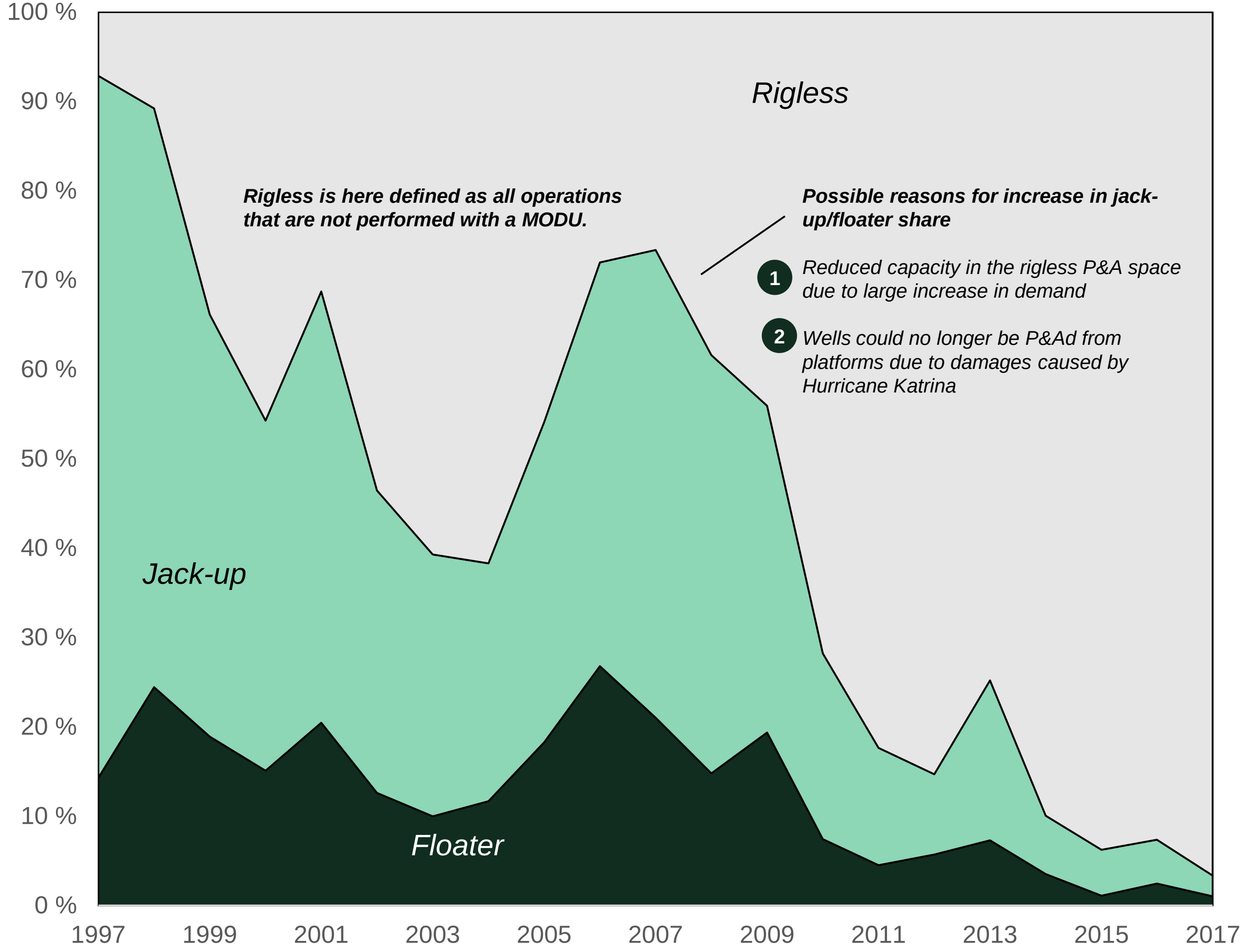
Expected P&A scope on the NCS from 2020-2025 (P&A forum)
Planned P&A operations by operators



Source: P&A forum; NPD; Rystad Energy research and analysis

There has been a structural shift towards rigless P&A operations in US Gulf of Mexico

Share of P&A operations split by unit category
%



Rigless is here defined as all operations that are not performed with a MODU.

Possible reasons for increase in jack-up/floater share

1. *Reduced capacity in the rigless P&A space due to large increase in demand*
2. *Wells could no longer be P&Ad from platforms due to damages caused by Hurricane Katrina*

Source: BSSE; Rystad Energy research and analysis

- The chart shows the share of P&A operations for different unit categories.
- We see that rigless methods have increased their share of the P&A operations over time. In 1997, these accounted for less than 10% of the operations, while in 2016 more than 90% of the operations were rigless. The chart shows the structural shift towards the rigless methods.
- The period from 2005 to 2010 differs from the overall trend with an increase in P&A done from jack-ups and floaters. This is both related to the aftermath of Hurricane Katrina where many platforms were damaged and would therefore need mobile drilling rigs to do the P&A, and the implementation of the US Idle Iron policy.
- This is also consistent with interviews, confirming that most P&A operations now are done rigless.

Report contents

Emission dimension: Metrics for Norwegian competitiveness

Exploration | **Development** | **Production** | **Abandonment**

Production:

- Upstream emission intensity ①
- Extraction intensity
Flaring intensity ②

Chapter synopsis

① NCS has the lowest upstream emission intensity among all oil and gas supply regions.

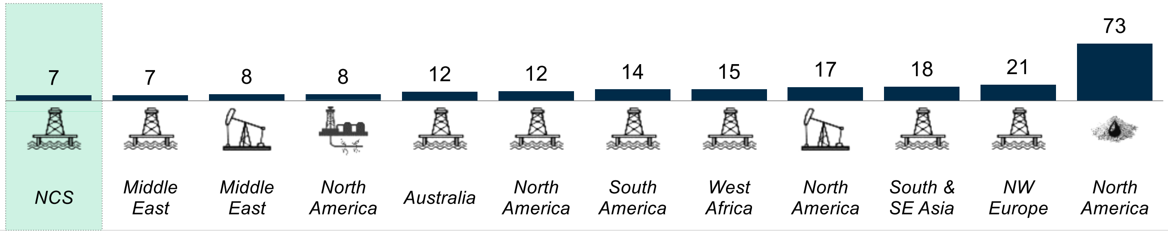
② The NCS comes out on top both on flaring and extraction emission intensity. This is a result of both strict flaring regulations and low extraction emission focus over time.

NCS has the lowest upstream emission intensity in the world

Key indicators for competitiveness

Comment

Extraction intensity* (kg CO2/boe)

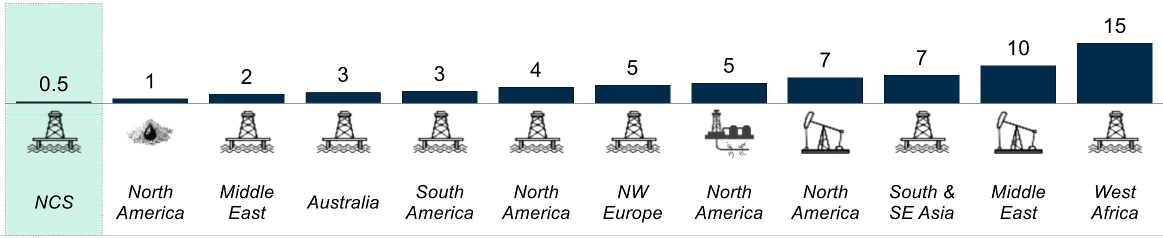


*Upstream extraction CO2 emissions over produced volumes. Includes emissions from extraction, production drilling, gathering and boosting. Average of 2019 and 2020.

The NCS has the lowest extraction emission intensity in the world. However, several other regions have catched up through the latest years. The overall trends shows a slight decrease in extraction intensity in all regions since 2018.

+

Flaring intensity (kg CO2/boe)**



**Upstream flaring and venting CO2 emissions over produced volumes. Includes emissions from routine and non-routine flaring and venting. Average of 2019 and 2020.

NCS flaring intensity is at the same level as in 2018, driven by the strict flaring regulations leaving only non-routine flaring allowed. The World Bank has launched a "Zero Routine Flaring by 2030" initiative that both global and local E&Ps over the world have included into their strategy over the last years. Flaring emissions are therefore expected to reduce heavily over the next decade.

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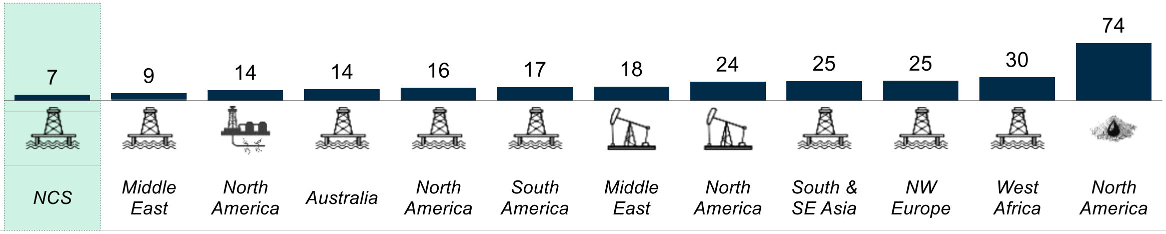
Total upstream emission intensity* (kg CO2/boe)**



***Toal upstream emissions from extraction and flaring over produced volumes. Average of 2019 and 2020.

The NCS also has the lowest total upstream emission intensity in the world due to both low extraction emission intensity and low flaring intensity. Other regions with low extraction intensity should have the potential to reduce emission intensity to NCS levels by stricter flaring regulations. Extraction emissions are often more complex to reduce.

- NCS has the lowest extraction emission intensity together with Middle East offshore. This is caused by electrification and low emission focus over time.
- The low flaring intensity is a result of strict flaring regulations, banning routine flaring.
- NCS has the lowest total upstream emission intensity among all oil and gas supply regions.

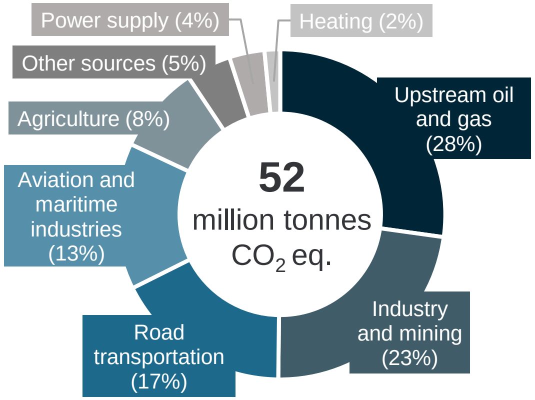
Source: Rystad Energy UCube; Rystad Energy EmissionsCube

Offshore
Shale unconventional
Onshore conventional
Oil sands unconventional

Oil and gas key to reach national emission goals – platform turbines should be the target

Norwegian GHG emissions and sources in 2018 (Scope 1)

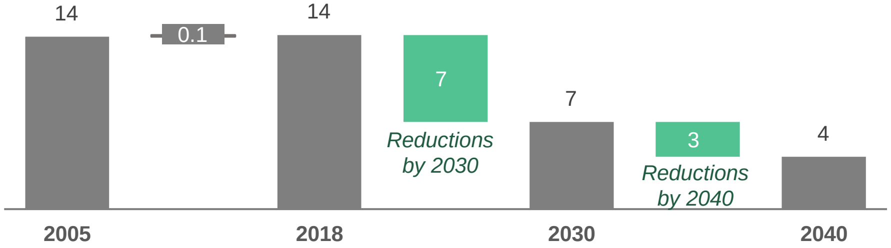
Million tonnes CO_2 equivalent and percent of total*



The upstream sector accounts for the largest share of Norwegian emissions compared to other industries

Stated reduction ambitions from Norwegian Oil and Gas

Emission targets - Million tonnes CO_2 equivalent

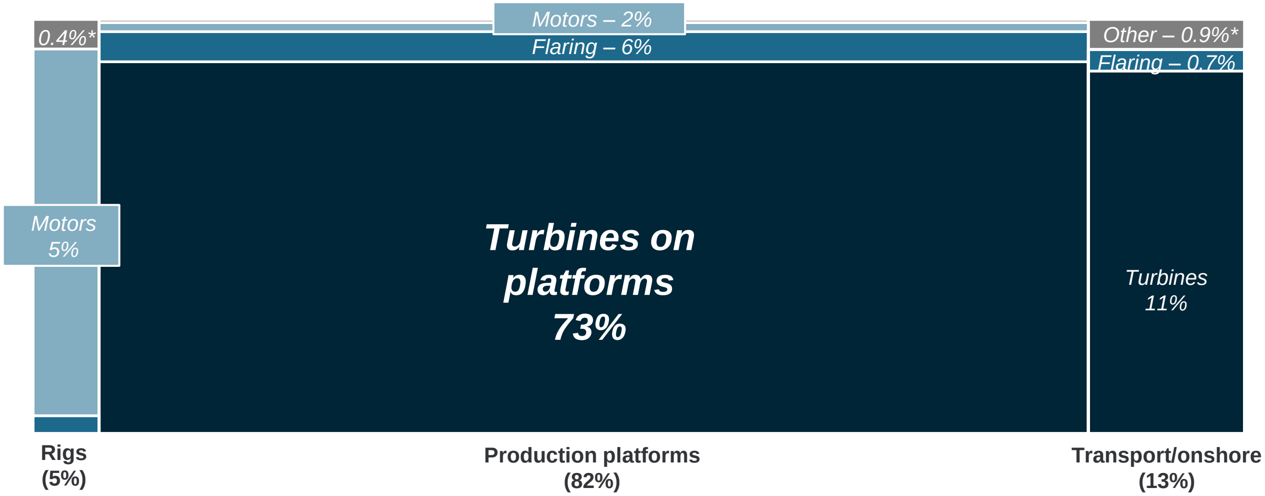


The Norwegian oil and gas industry has recently echoed the Norwegian government's climate ambitions, stating:

- 2030: 50% reductions compared 2005 emissions
- 2040: 70% reductions compared 2005 emissions
- 2050: Near zero emissions

Upstream CO_2 emissions from the NCS in 2018, by emission source and activity

% of the total 12.9 Mt CO_2 emitted

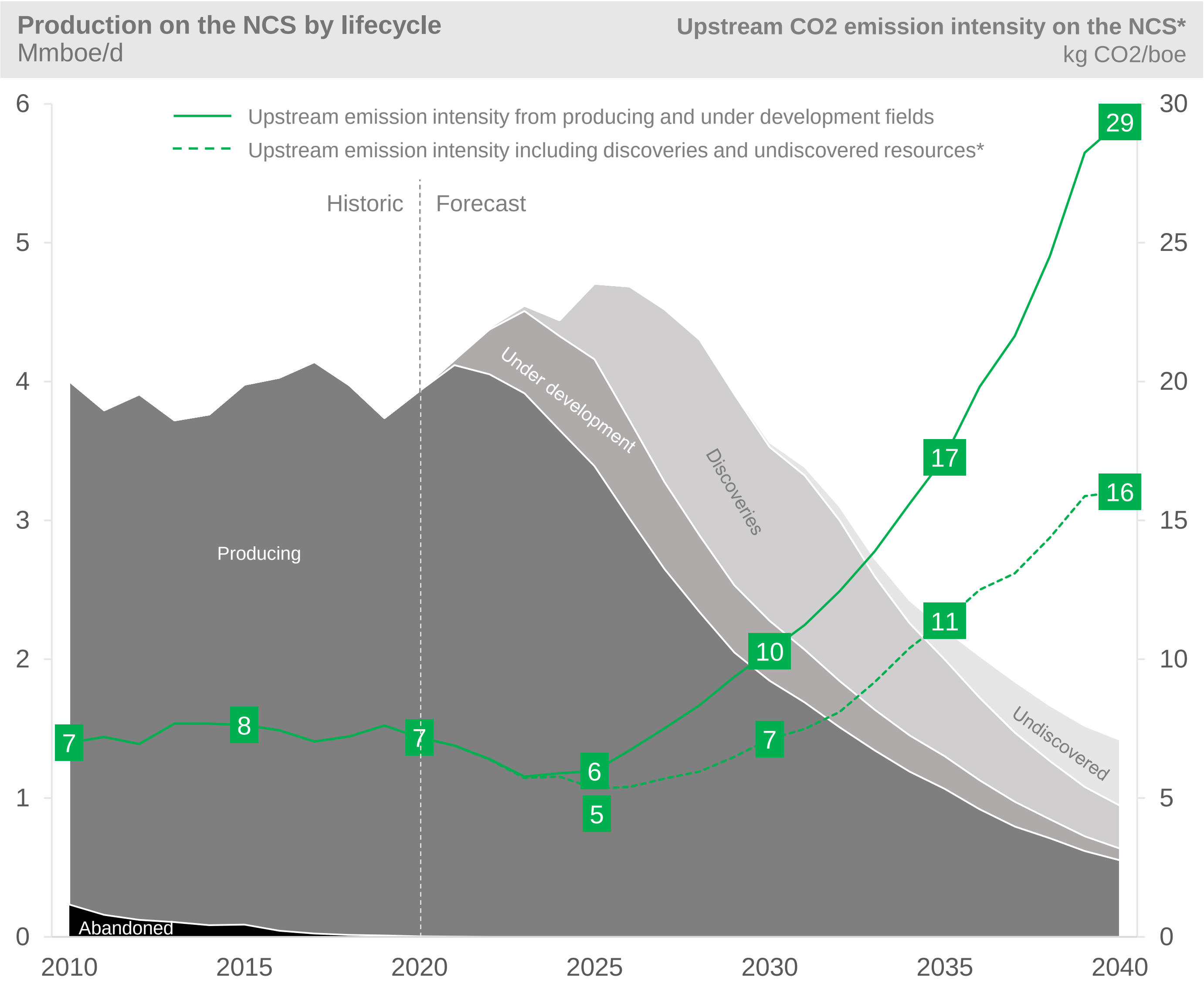


- Almost three quarters of the CO_2 emissions on the NCS come from energy generation on platforms, through gas and diesel burned in turbines.
- To achieve the stated targets we will need to address the turbines through either electrification, turbine efficiency improvements or reduced energy demand.
- Looking to electrification, offshore wind is especially suited to reduce turbine emissions without affecting demand for new power generation onshore

*Includes other greenhouse emission gases in addition to CO_2

Source: Norwegian Oil & Gas; NPD; SSB; Rystad Energy research and analysis

With NCS production in decline, CO_2 intensity increases unless measures are taken

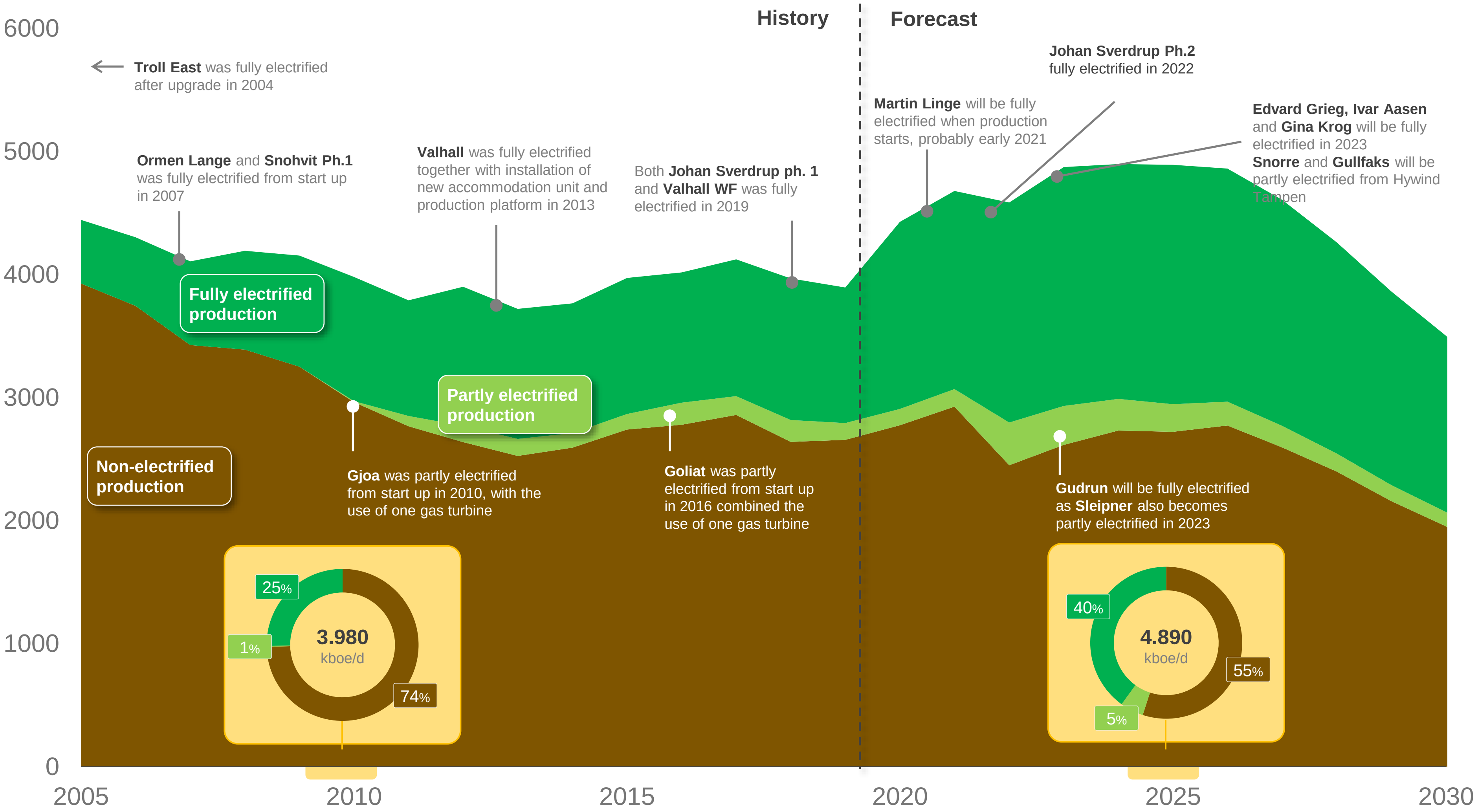


- The area chart shows production from all fields on the NCS, while the lines represent the weighted average emission intensity on the NCS from 2010 to 2040, the dotted line excluding discoveries and fields yet to be found.
- Emissions intensity is a metric for emissions generated per barrel of oil equivalents produced.

*Only from opened exploration areas
Source: Rystad Energy EmissionsCube

Electrification has been a success in terms of emissions on the NCS

NCS hydrocarbon production by electrification category from 2005 to 2030*
Thousand barrels per day



← **Troll East** was fully electrified after upgrade in 2004

Ormen Lange and **Snohvit Ph.1** was fully electrified from start up in 2007

Valhall was fully electrified together with installation of new accommodation unit and production platform in 2013

Both **Johan Sverdrup ph. 1** and **Valhall WF** was fully electrified in 2019

Martin Linge will be fully electrified when production starts, probably early 2021

Johan Sverdrup Ph.2 fully electrified in 2022

Edvard Grieg, Ivar Aasen and **Gina Krog** will be fully electrified in 2023

Snorre and **Gullfaks** will be partly electrified from Hywind Tampen

Gjoa was partly electrified from start up in 2010, with the use of one gas turbine

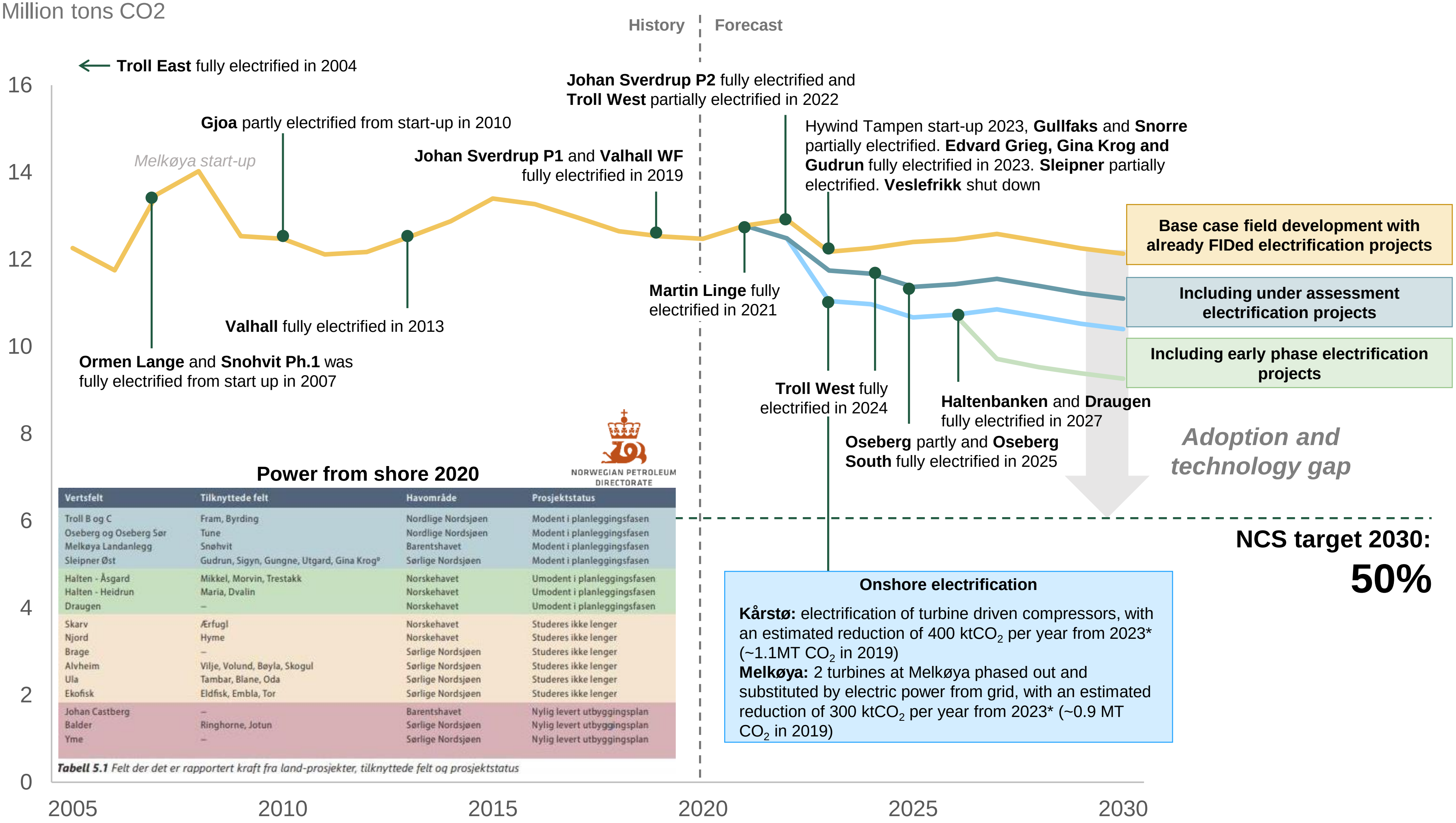
Goliat was partly electrified from start up in 2016 combined the use of one gas turbine

Gudrun will be fully electrified as **Sleipner** also becomes partly electrified in 2023

Source: Rystad Energy EmissionsCube; *Does not include projects that have not taken FID yet, e.g. Troll West and Oseberg (July 10th 2020)

Still, significant gap to close in order to reach 2030 emission targets

Upstream emission volumes on the NCS from 2005 to 2030, including flaring
Million tons CO2



← **Troll East** fully electrified in 2004

Gjoa partly electrified from start-up in 2010

Johan Sverdrup P1 and **Valhall WF** fully electrified in 2019

Johan Sverdrup P2 fully electrified and **Troll West** partially electrified in 2022

Hywind Tampen start-up 2023, **Gullfaks** and **Snorre** partially electrified. **Edvard Grieg, Gina Krog and Gudrun** fully electrified in 2023. **Sleipner** partially electrified. **Veslefrikk** shut down

Base case field development with already FIDed electrification projects

Including under assessment electrification projects

Including early phase electrification projects

Martin Linge fully electrified in 2021

Valhall fully electrified in 2013

Ormen Lange and **Snohvit Ph.1** was fully electrified from start up in 2007

Troll West fully electrified in 2024

Haltenbanken and **Draugen** fully electrified in 2027

Oseberg partly and **Oseberg South** fully electrified in 2025

Adoption and technology gap

NCS target 2030:

50%

Power from shore 2020

Vertsfelt	Tilknyttede felt	Havområde	Prosjektstatus
Troll B og C	Fram, Byrding	Nordlige Nordsjøen	Modent i planleggingsfasen
Oseberg og Oseberg Sør	Tune	Nordlige Nordsjøen	Modent i planleggingsfasen
Melkøya Landanlegg	Snøhvit	Barentshavet	Modent i planleggingsfasen
Sleipner Øst	Gudrun, Sigyn, Gungne, Utgard, Gina Krog[9]	Sørlige Nordsjøen	Modent i planleggingsfasen
Halten - Åsgard	Mikkel, Morvin, Trestakk	Norskehavet	Umodent i planleggingsfasen
Halten - Heidrun	Maria, Dvalin	Norskehavet	Umodent i planleggingsfasen
Draugen	–	Norskehavet	Umodent i planleggingsfasen
Skarv	Ærfugl	Norskehavet	Studeres ikke lenger
Njord	Hyme	Norskehavet	Studeres ikke lenger
Brage	–	Sørlige Nordsjøen	Studeres ikke lenger
Alvheim	Vilje, Volund, Bøyla, Skogul	Sørlige Nordsjøen	Studeres ikke lenger
Ula	Tambar, Blane, Oda	Sørlige Nordsjøen	Studeres ikke lenger
Ekofisk	Eldfisk, Embla, Tor	Sørlige Nordsjøen	Studeres ikke lenger
Johan Castberg	–	Barentshavet	Nylig levert utbyggingsplan
Balder	Ringhorne, Jotun	Sørlige Nordsjøen	Nylig levert utbyggingsplan
Yme	–	Sørlige Nordsjøen	Nylig levert utbyggingsplan

Tabell 5.1 *Felt der det er rapportert kraft fra land-prosjekter, tilknyttede felt og prosjektstatus*

Onshore electrification

Kårstø: electrification of turbine driven compressors, with an estimated reduction of 400 $ktCO_2$ per year from 2023* (~1.1MT CO_2 in 2019)
Melkøya: 2 turbines at Melkøya phased out and substituted by electric power from grid, with an estimated reduction of 300 $ktCO_2$ per year from 2023* (~0.9 MT CO_2 in 2019)

Source: Rystad Energy UCube

Future electrification projects can reduce emissions by almost 2.5 million tonnes of CO2

Status	Field	Emissions*, kt CO2, 2019	Reduction potential, kt CO2/y	Electrification year	Comment
FID	Martin Linge	0	200	2021	Installation of 162km subsea power cable to Kollsnes onshore completed in 2018. Martin Linge is scheduled to come on stream in 2021.
	Johan Sverdrup ph 2	0	*Includes phase 1* 600	2022	Will be fully electrified with power from shore and act as hub for electrification of Utsira High area, including Sleipner and its tie-ins.
	Edvard Grieg	245	200	2022	Will be fully electrified from Johan Sverdrup Phase 2. Solveig and Rolvsnes consist of subsea tie-ins and are scheduled to start production in Q4 2021 and Q2 2022 respectively and have been included in potential emissions reductions.
	Ivar Aasen	0	100	2022	Ivar Aasen is a steel platform currently powered by Edvard Grieg, where emissions are realized.
	Gina Krog	120	100	2022	Will be fully electrified from Johan Sverdrup Phase 2. Gina Krog will also act as a hub for subsequent electrification of Sleipner field center.
	Gullfaks	800	140	2023	Both Gullfaks and Snorre will be electrified as part of the Hywind Tampen offshore floating wind installation, consisting of 11 wind turbines with a combined capacity of 88 MW. It will partially electrify both fields resulting in a reported cumulative reduction of 200 kt CO2/y, which we have allocated proportionally based on 2019 emissions. Hywind Tampen scheduled for start up end-2022
	Snorre	340	60	2023	
	Sleipner	580	250	2023	Partially electrified as an extension of Johan Sverdrup ph. 2, powered by a cable from Gina Krog. Field tie-ins include Utgard, Gungne, Sigyn and the steel platform Gudrun which is powered from Sleipner.
Under assessment	Troll Oil (West)	590	450	2022	Partial electrification of Troll B (-85 kt CO2) and full electrification of Troll C (-365 kt CO2). Troll B full electrification expected in 2024. FEED contract already signed with Aker Solutions, PDO expected in 2021.
	Oseberg	790	400	~2025	Electrification potential currently under assessment. Estimated 50% reduction of 2019 level emissions from 2025 onward.
	Oseberg South	180	60	~2025	
Early planning phase	Haltenbanken	1100	Undecided	Unknown	According to the *Power from shore* 2020 report from NPD, Haltenbanken and Draugen are in the early planning phase for power from shore. This includes Åsgard and Heidrun, with tie-ins Mikkel, Morvin, Trestakk, Maria and Dvalin. In addition to Draugen.
	Draugen	180	Undecided	Unknown	

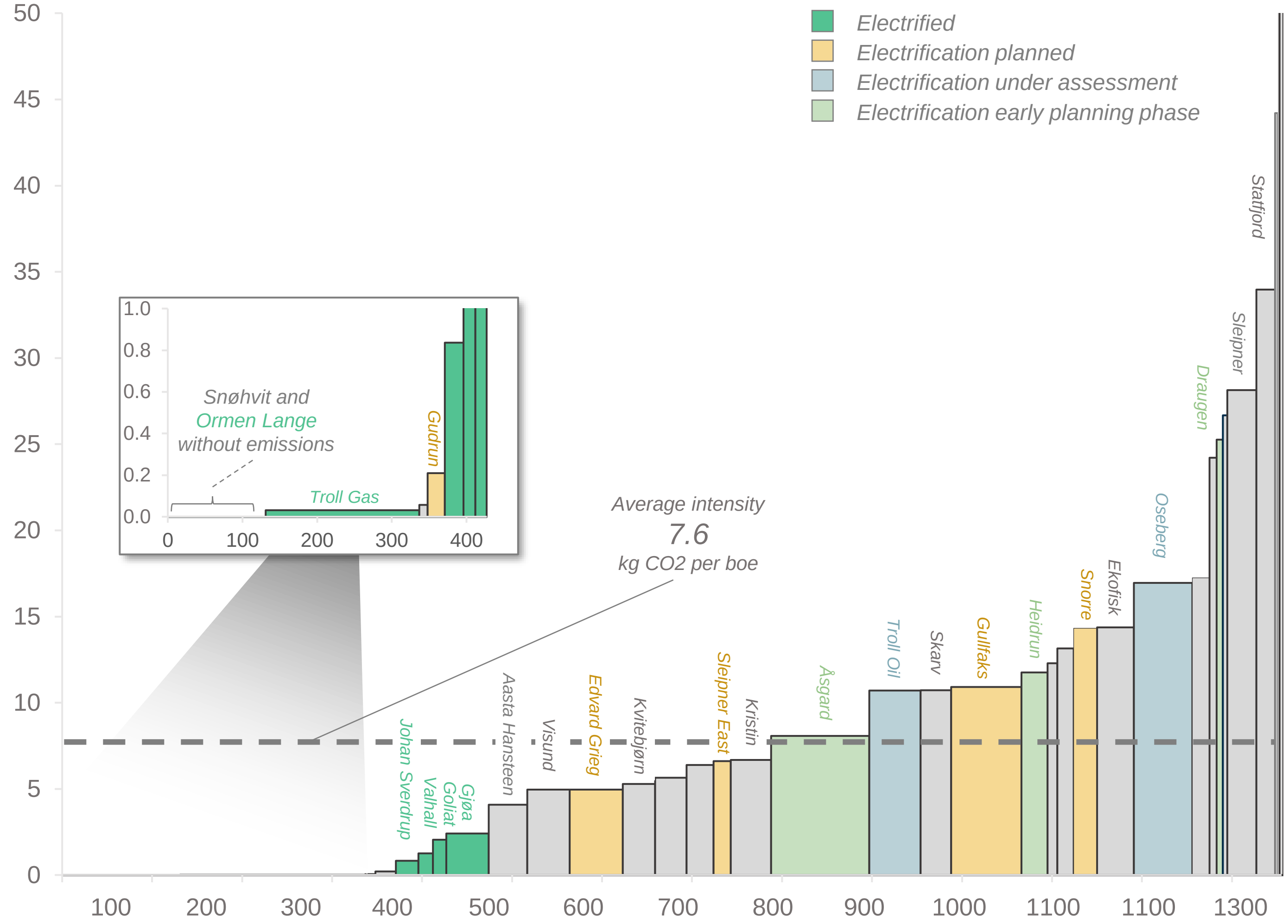
*Extraction emissions, excludes flaring

Source: Rystad Energy research and analysis, Equinor, Norwegian Oil and Gas

Full electrification Partial electrification

Emission intensity spread between hubs on the NCS is widespread

Emission intensity from production by hub, 2019*
Kg CO2 per boe

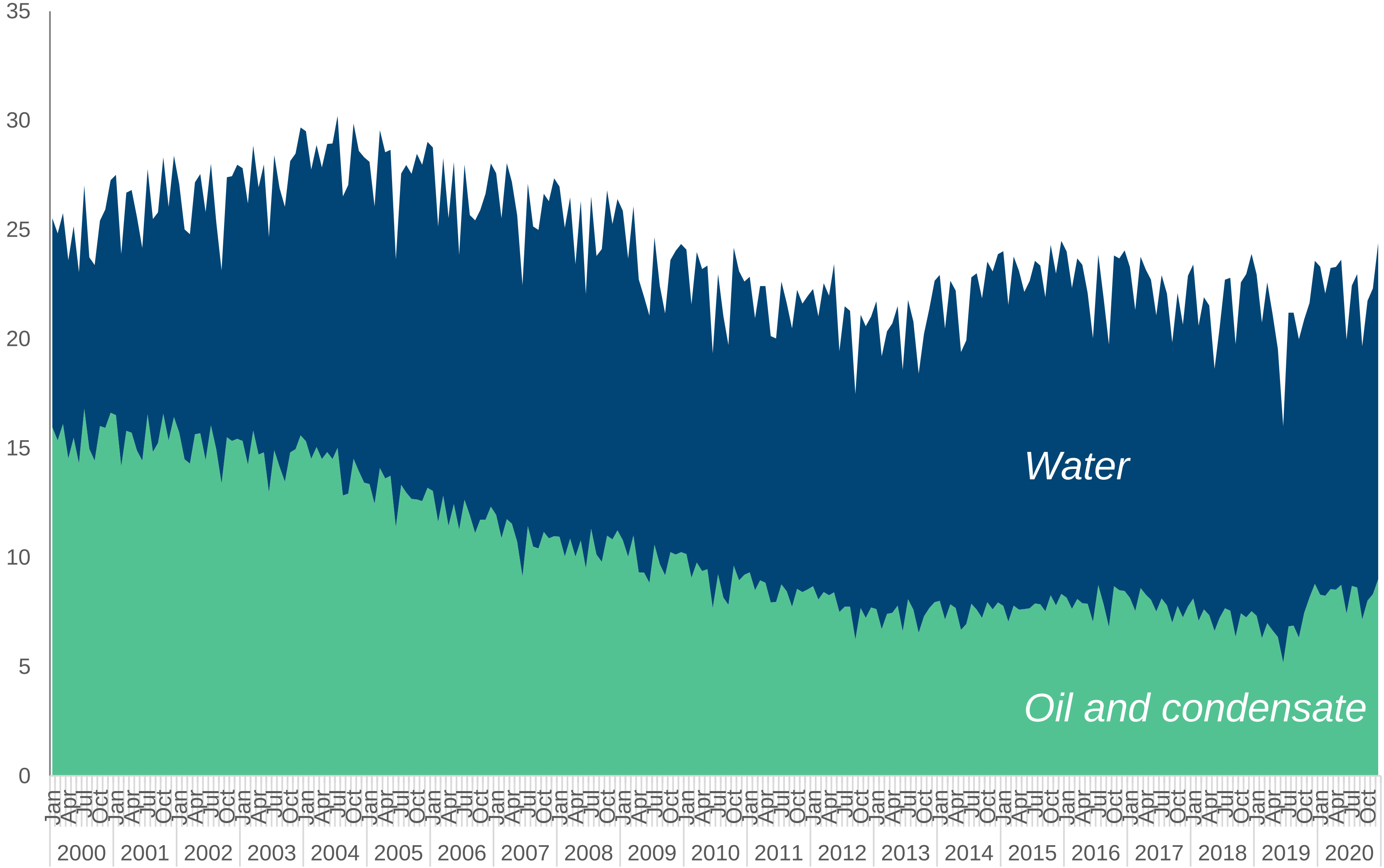


- The graph shows the Norwegian oil and gas producing hubs by production (x-axis, cumulative) and emission intensity (y-axis).
- The average upstream emissions on the NCS was in 2019 7.6 kg CO2 per boe (excluding production drilling) – the spread between hubs is however wide.
- The CO2 emission intensity for subsea fields with tieback to shore is 0 as the emissions are allocated to the onshore bases – this is the case both for Snøhvit and Ormen Lange
- The ongoing electrification projects will change the overall landscape of assets emissions

*Based on reported 2019 numbers, includes production from tiebacks to host. Scope 1 and CO2 only; excluding CH4, NOx etc.
Source: Rystad Energy research and analysis; Field specific environmental reports

The NCS is first and foremost a water producing basin

NCS liquids production by type
Million sm3



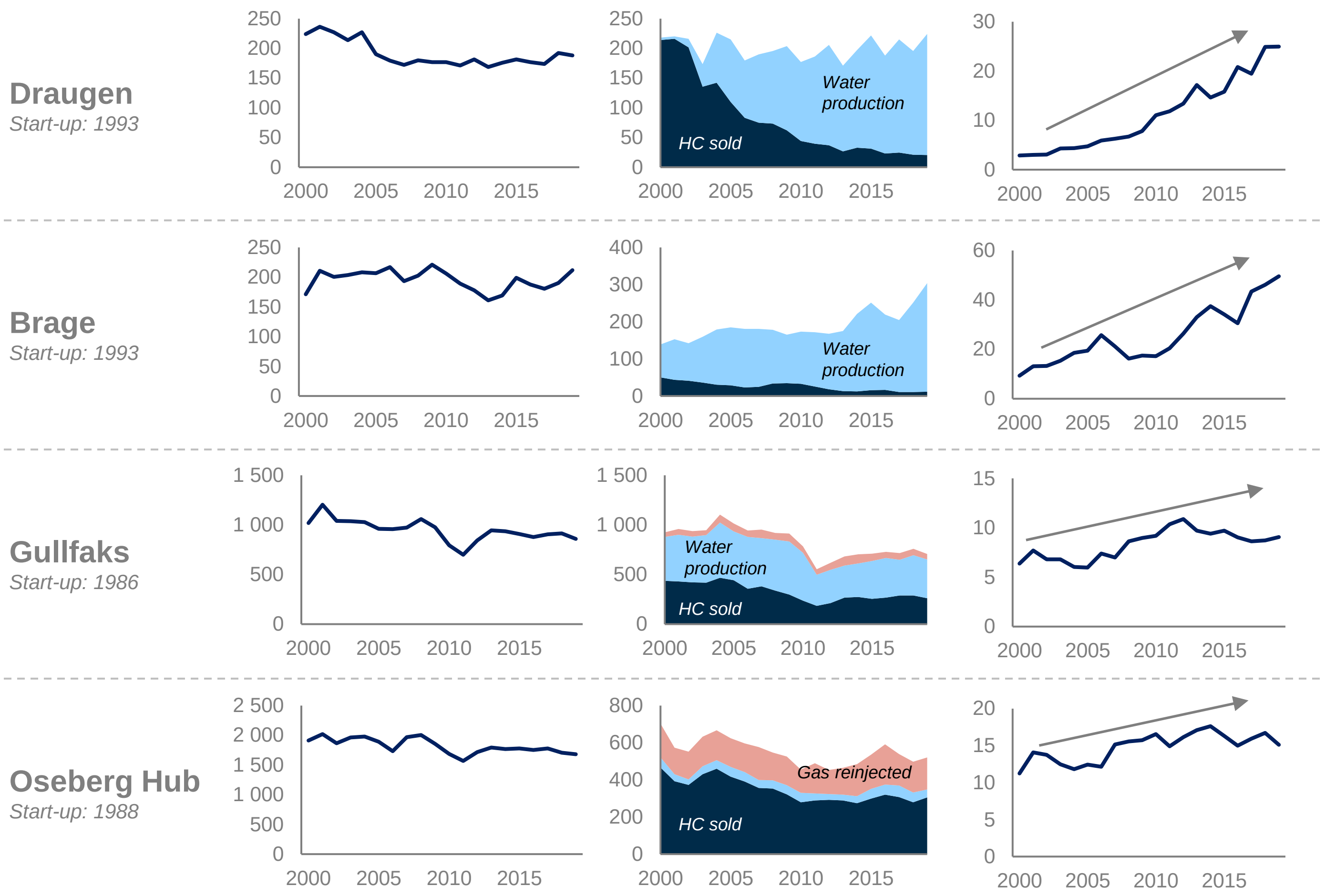
2020 avg:
63% water

Source: NPD; Rystad Energy research and analysis

Emission intensity is largely a function production levels and water handling

Reported upstream emissions for selected fields on the Norwegian continental shelf

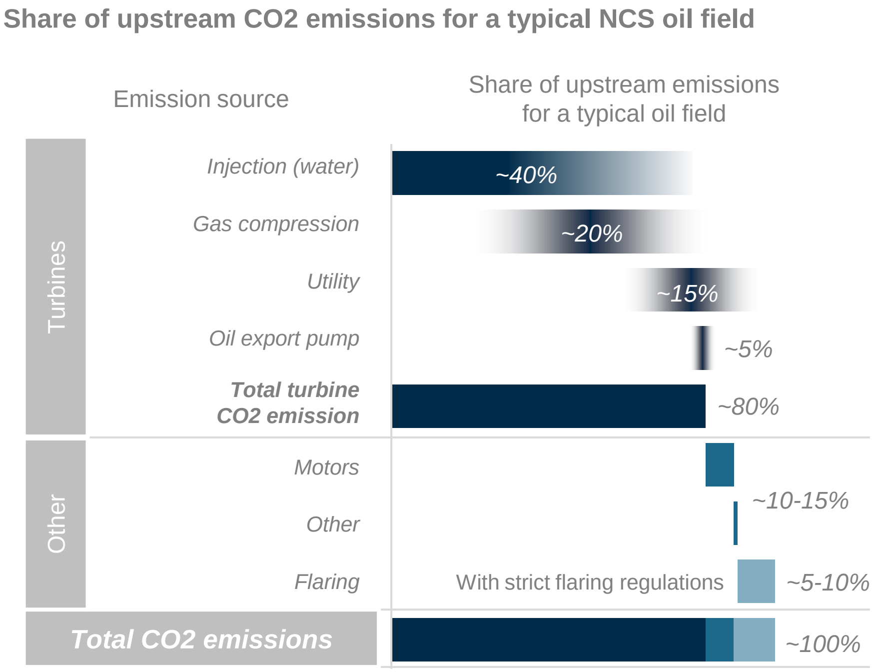
Field	*Upstream CO2 emissions** [thousand tonnes]*	/	*HC production [thousand boepd]*	=	*CO2 emissions per barrel [kg CO2/boe]*

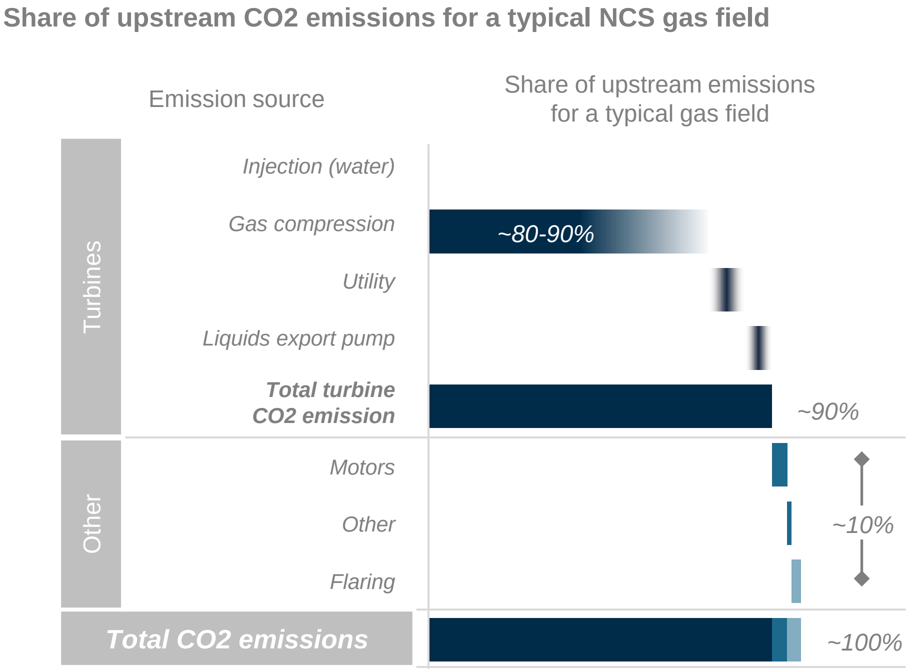


- Upstream CO$_2$ emissions for four selected offshore fields on the Norwegian continental shelf (NCS) clearly show that CO$_2$ emissions per boe increases over the lifetime of the fields.
- Upstream CO$_2$ emissions are relatively stable, despite a drop in production as conventional fields mature. This is driven by more efforts required to extract late-phase barrels, typically resulting in an increased need for separation due to high water cut and increased injection activity to maintain reservoir pressure.
- Upstream emissions from offshore fields on the NCS are reported annually, including CO$_2$ emissions from generation of power, heat and flaring.

*Includes CO2 emissions from the extraction phase (ex. development drilling). Exploration activity and flaring are excluded.
Source: Rystad Energy research and analysis; Norsk Olje og Gass

Source distribution for a generic field – injection and compression drives CO2 emissions



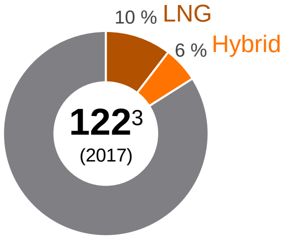
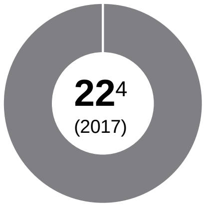
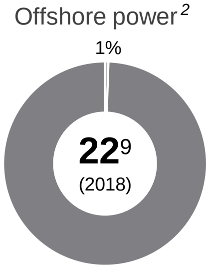


- The above charts show the distribution of key emission sources for a typical NCS oil (left) and gas (right) field. For oil fields, more than 80% of the emission stems from turbines driving generators and compressors. Water injection is the most energy intensive operation together with gas compression (injection or export of associated gas), while for gas fields, gas compression for transport is dominating.
- For areas like the NCS with strict flaring regulations, flaring constitutes a minor part of the total upstream CO2 emissions.
- Emissions from gas turbines varies based the degree of energy efficiency. The energy efficiency depends on optimization of the compressor design, efficiency of the gas turbine etc. On the NCS the emission related to use of gas turbines has for field such as Valhall been "removed" as a result of a power from shore solution.

Source: Rystad Energy Research and analysis; Life of Field Energy Performance, 2003, Stig Svalheim

Relevant offshore maritime supply segments represent 1.9 MT domestic CO2 emission in 2017

Defining offshore maritime supply chain segments

Segment	Description	2017 emissions[1] [ktonnes CO2]		No. Units	Existing emission target	
		Domestic	*In Norway*	*per technology*	*Domestic*	*International*
Offshore supply vessels (OSV) 	Segment covering Kysteverkets vessel category: • *Offshore Supply Ship* • *Other offshore Service Ship* Main vessel types are PSVs, ERRVs, AHTSs and OCVs.	**1096** *AIS based*	**1181** *AIS based*		50% *Reduction in domestic maritime GHG emission by* 2030 *(relative to 2005)[5]*	50% *Reduction in international maritime GHG emission by* 2050 *(relative to 2008)[7]*
Shuttle tankers 	Segment covers Shuttle Tankers. Shuttle Tankers is a part of Kystverkets vessel category: • *Crude Oil Tankers*	**174**[8] *AIS based*	**552**[8] *AIS based*			
Rig 	Segment covering all movable drilling units (MODUs) operating on the NCS, both development and exploration drilling. Transit and idle rigs are not included.	**606** *Reported*	**606** *Reported*		2.5 million CO2 equivalents a year; 2020-30[6] For the petroleum industry	*Covered by overall international emission targets*

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1) Regjeringens handlingsplan for grønn skipsfart (2019) for OSVs and Shuttle tankers and Norsk Olje og Gass for Rigs 2) Maersk Invisible on Valhall. 3) Innenriks/domestic – defined as 80% of time in Norway 4) As of January 2017 Includes Contract of Affreightment (CoA) fleet in the North Sea; 5) As staded in Granavolden-plattformen 6) Report: Veikart for norsk sokkel 7) IMO strategy as of 2018; 8) Emission represents the whole crude oil tanker segment 9) The number of rigs demanded per year (working 275 days/year);
Source: Rystad Energy research and analysis; Handlingsplan for grønn skipsfart (DNV); Norsk Olje og Gass

Report contents

On international benchmarks for HSE statistics

- There are several apparent weaknesses and caveats to consider when trying to benchmark HSE performance across cultures and regulatory regimes.

- Apparent poor performance is possibly a sign of good performance as it may involve fewer cases of under-reporting.

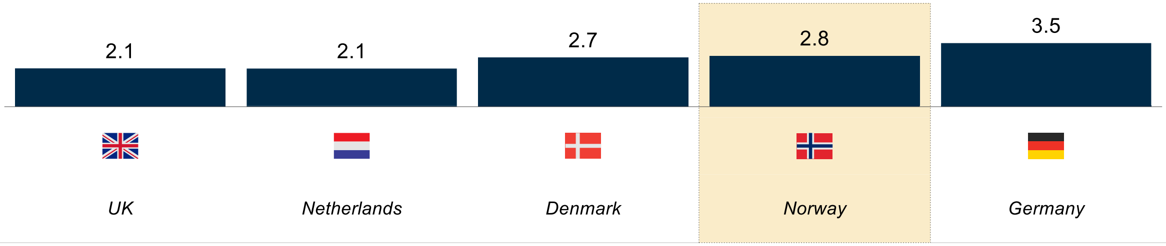
- Such may be the case when benchmarking the Norwegian oil and gas industry's HSE performance against other countries. A higher LTIF metric is shown, despite a similar TRIR metric.
    - This may reflect Norwegian HSE culture being «more serious» about injuries, allowing workers the needed time to recover.
    - Similarly, it may imply less willingness to «cooking the stats» in order to reach KPI targets for HSE

Norway on par with DK and Ger on TRIR metric, but reports far poorer figures on LTIF

Key indicators for competitiveness

Comment

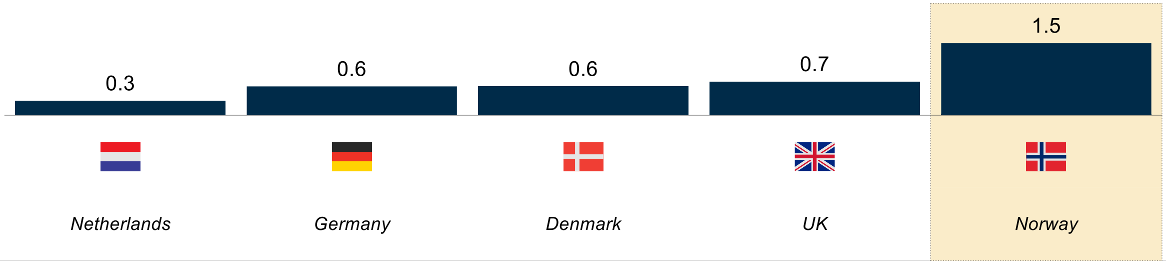
Total recorded injury rate for oil and gas



Norway scores in the higher end among Northern European countries on total injury frequency, being on par with Denmark, and with only Germany having a poorer KPI. The Netherlands relies mostly on onshore facilities, something which may contribute to a better metric.

Total recorded injury frequency includes fatalities, lost work day cases, restricted work day cases and medical treatment cases. Normalized by million work hours. Figures are for 2018.

Lost time injury frequency for oil and Gas



While on par with the other countries on the TRIR metric, Norway is far above on LTIF, indicating that the injuries sustained leave workers idle twice as often. This may not be a reflection of the severity of the injuries, but can possibly also be explained by stricter regulatory standards.

Injuries leading to lost work time by incapacitating worker exposed to injury. Normalized by million work hours. Figures are for 2018.

Can the data be trusted?

In general, IOGP statistics comparing HSE performance across geographies appear to not represent fair comparisons. Several characteristics of the data point to this:

1. Other geographies (Africa, Asia, South America) consistently score better than Europe on TRIR and LTIF metrics. Weak institutions related to HSE is a likely explanation, which results in underreporting from these regions.
2. This notion is further supported by fatality statistics not correlating with injury or incident frequencies, something IOGP also state themselves.

Consequently, countries that ***likely have comparable regulatory frameworks to Norway*** have been chosen as benchmarks above, Norther European oil and gas producers. The reader is still encouraged to keep the inherent weaknesses in the data in mind when considering it, also for the peer countries chosen.

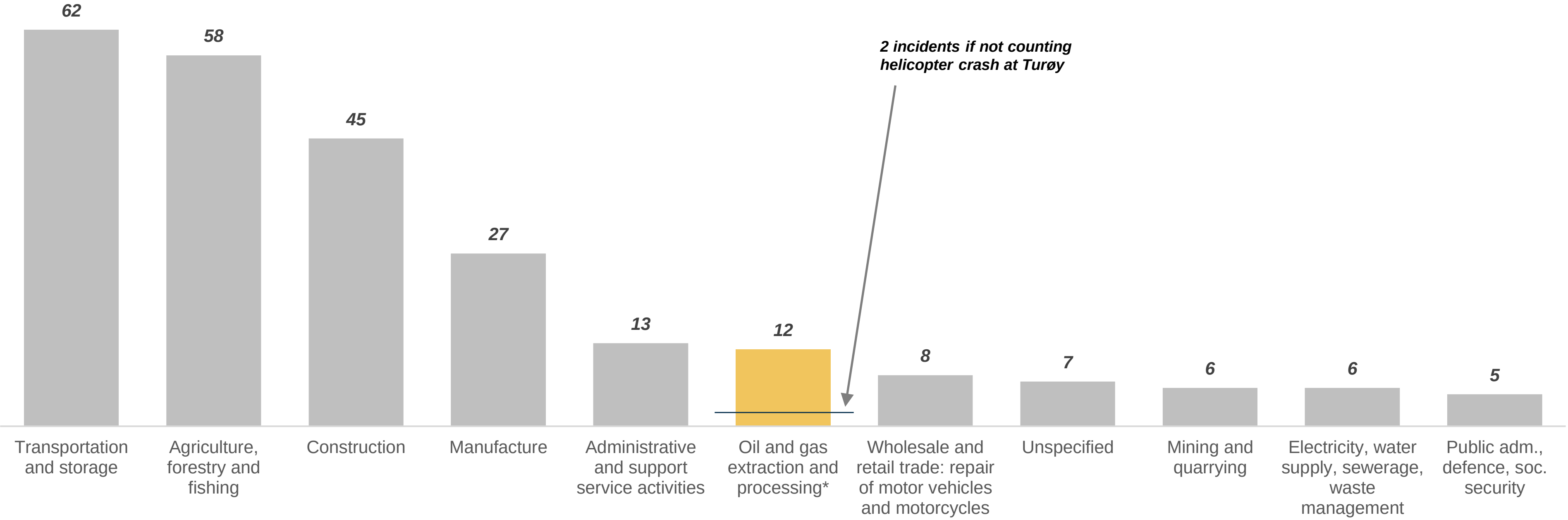
> *«For comparison, the 5-year rolling average FAR [Fatal Accident Rate] is shown for each of the regions. There appears to be little if any correlation between these values and the regional average LTIF and TRIR values."*

From IOGP's Safety Performance Indicators databook for 2018

Source: Rystad Energy research and analysis, IOGP

Oil and gas extraction and processing with fewer fatalities than other industries

SSB work related fatalities 2014 to 2019 by industry
Number of fatalities



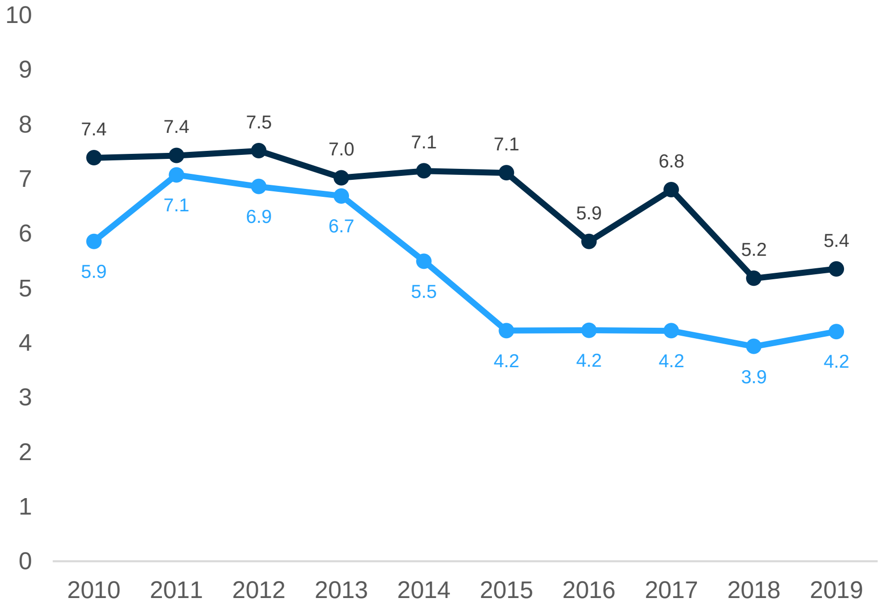
2 incidents if not counting helicopter crash at Turøy

- Although one fatality is always one too much, comparisons across industries in Norway on work related deaths shows the oil and gas industry as favorable compared to others like transportation and storage, agriculture and fishing, and construction.
- The oil and gas figure of 12 fatalities includes 10 fatalities related to «Turøyulykken», where a helicopter returning from Oseberg crashed outside Bergen leaving 13 casualties (3 fatalities not registered to «oil and gas extraction and processing»
- This means that offshore oil and gas activity regrettably has resulted in 2 deaths in the period between 2014 and 2019, both at drilling rigs (COSL Innovator in 2015 and Maersk Interceptor in 2017).

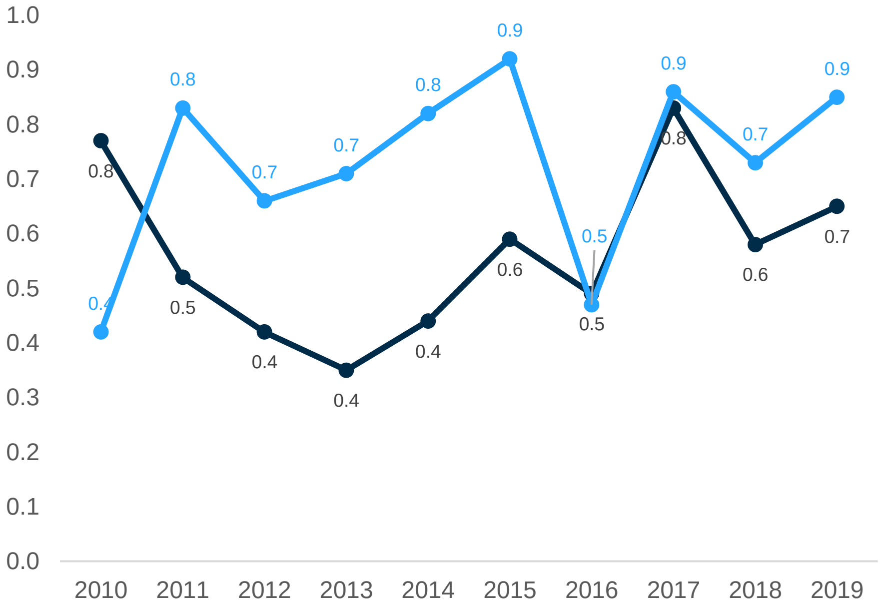
Only selected industries included, omitted industries are service heavy *Oil and gas extraction and processing defined as having PTIL as reporting regulator or Luftfartstilsynet as reporting regulator in conjunction with “Mining and quarrying” as defined industry; Source: Rystad Energy research and analysis; SSB

Decrease in injury rate not reflected in serous injury rate

Offshore injury frequency by facility type
Incidents per million work hours



Offshore <u>serious</u> injury frequency by facility type
Incidents per million work hours



Producing facility *Movable facility*

- Injury frequency (left chart) on the NCS has shown a decreasing trend since 2010 for both production facilities and movable facilities (which primarily consists of drilling rigs).
- From steady levels of about 7 cases per million work hours from 2010 to 2015, the level is now at 5.4 for production facilities.
- The serious injury rate has not decreased however, increasing to 0.7 in 2019 from 0.4 in the bottom year of 2013. Sliced HSE budgets in the wake of the 2014 oil price drop is one possible explanation.
- A different explanation is that serious incidents are more difficult to "hide". Safety KPIs are valued high for managers, both in internal performance evaluations and when being considered as contractors. Pressure to decrease incidents may lead to under-reporting.
- Movable facilities show serous injury rates that are consistently higher than those for production facilities. This is despite the overall injury rate being lower. Increased exposure to drilling and well related activities may serve as one explanation.

Injuries are work related; leisure related injuries omitted
Source: Rystad Energy research and analysis; PTIL RNNP 2019

Operations and maintenance most exposed to injuries on producing facilities

Offshore injury frequency on producing facilities by discipline
Incidents per million work hours

Offshore injury frequency on movable facilities by discipline
Incidents per million work hours

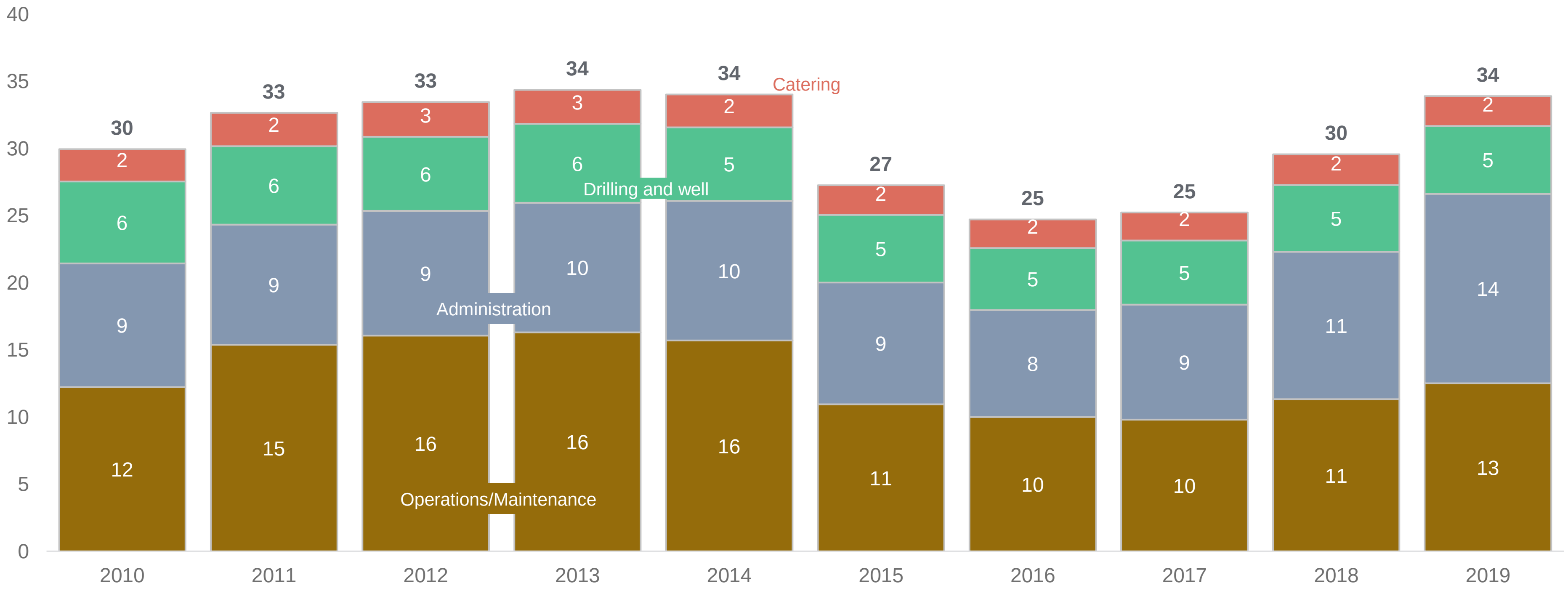
- Drilling and well related activity generally represents the highest injury rate of the disciplines on movable facilities (right chart). The trend has been broken in the last couple of years, with operations and maintenance representing an equally large injury frequency. Technology may have played a part in this, allowing workers to be less «hands-on» on the drilling equipment itself, and more able to handle drilling remotely.
- Operations and maintenance consistently has the highest injury frequency on producing facilities. One possible explanation for the difference between movable facilities and producing facilities in this regard is that movable facilities can have maintenance work done while at shore and not operational.
- The «Administration» discipline has the lowest injury frequency for both facility types.

Injuries are work related; leisure related injuries omitted
Source: Rystad Energy research and analysis; PTIL RNNP 2019

Administration with larger share of hours offshore in late 2010s – reason for reduced injuries?

Workhours on producing facilities by discipline

Million hours



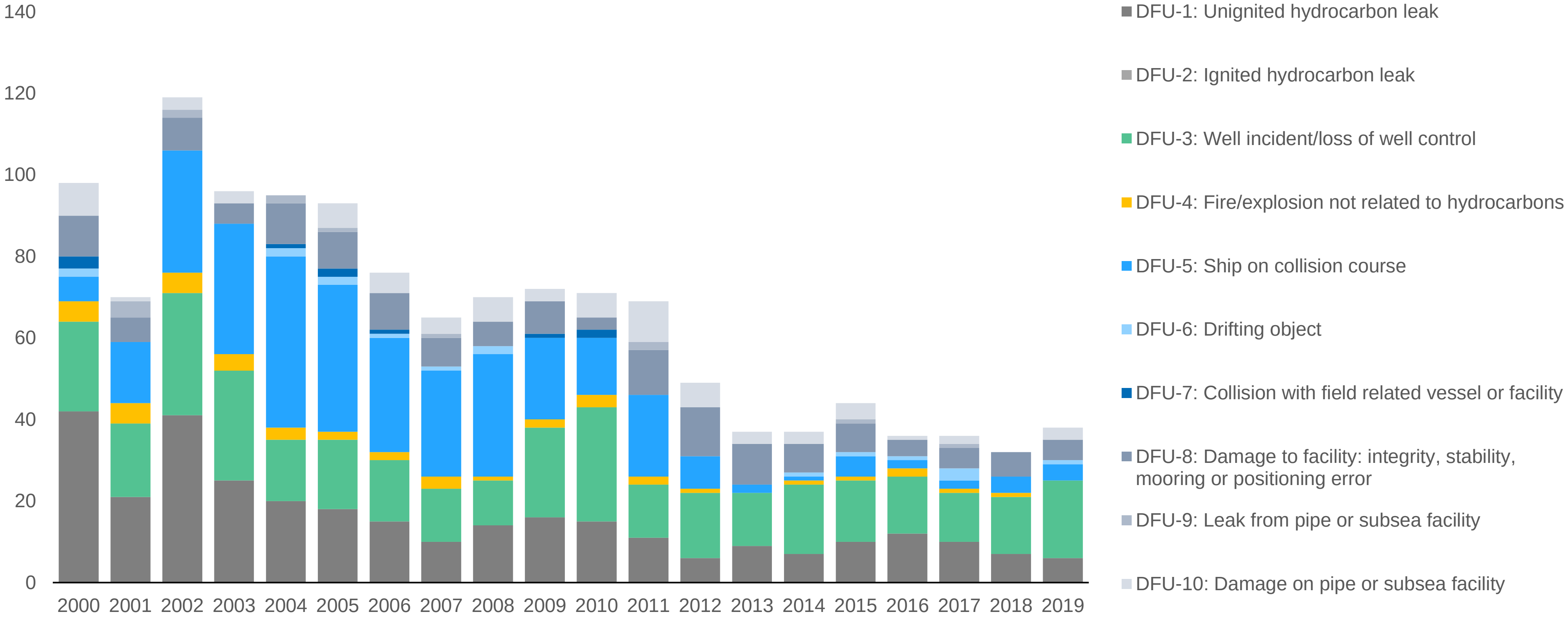
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Catering	2	2	3	3	2	2	2	2	2	2
Drilling and well	6	6	6	6	5	5	5	5	5	5
Administration	9	9	9	10	10	9	8	9	11	14
Operations/Maintenance	12	15	16	16	16	11	10	10	11	13
	30	33	33	34	34	27	25	25	30	34

- Following a dip in manhours from 2015 to 2017, activity levels on the NCS rose again in 2018 and 2019. The sharpest increase is for the «Administration» discipline.
- This may serve to explain the reduced injury frequency seen on producing facilities in recent years; admin workers are less exposed to injuries overall and now make up a larger share of the offshore workforce.

Source: Rystad Energy research and analysis; PTIL

Drilling and well with a large share of incidents with major accident potential

Number of offshore incidents with major accident impact
Number of incidents



- Incidents with potential for being major accidents have fallen steadily on the NCS since 2000.
- The decrease is largely due to DFU-5 being reduced significantly, fewer ships on collision course have been registered. One possible explanation is digital tools being used to give a better overview of vessel positions in real-time.
- Well incidents remain as the most frequent type of incident with major accident potential. Hydrocarbon leaks and facility damage both represent large shares in 2019 as well.

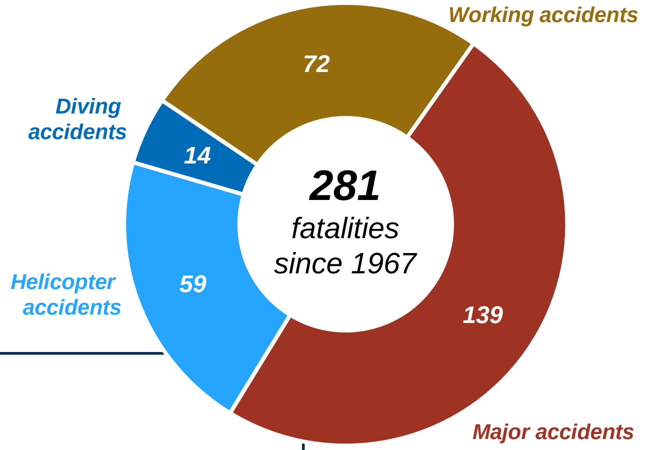
Source: Rystad Energy research and analysis; PTIL

How to account for «unknown unknowns» possibly leading to fatalities?

Forebygging av storulykker skal prege 2020

PTIL has stated that preventing major accidents is a priority for the authority's work in 2020. The ambition is to never have a major accident occur on the NCS again

Fatalities on the NCS from 1967 to 2019 by cause



Examples of high impact incidents

Turøy

Alexander Kielland

(Non-NCS)
Deepwater Horizon

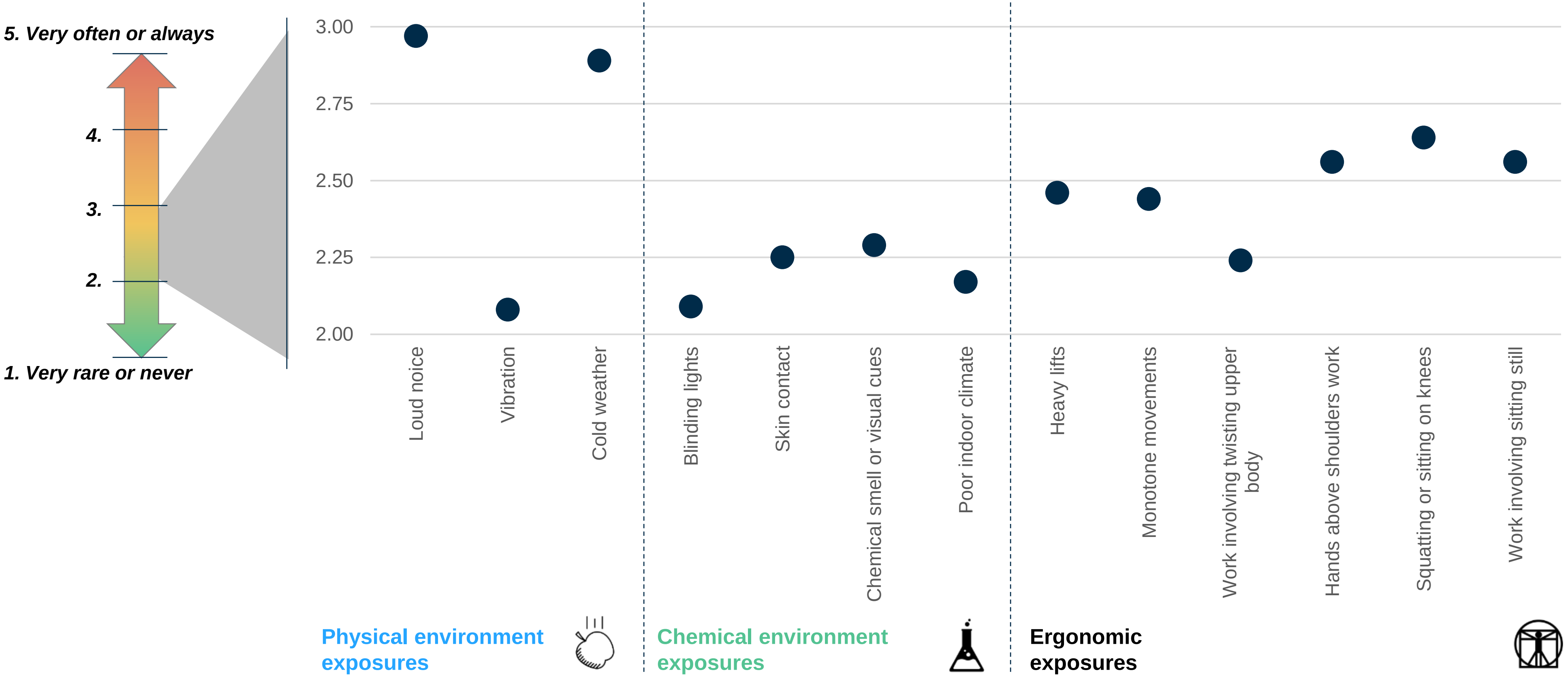
*High impact incidents such as the Turøy helicopter crash in 2016 **(13 fatalities)** and the major accident at the Alexander Kielland floatel in 1980 **(123 fatalities)** have had large impact on the overall fatality statistics on the NCS*

*To the degree that potential high impact incidents have happened before, their causes can be used to prevent future occurrences. Yet if this was a way to prevent all high impact incidents, they would never occur at all (given full compliance to all safety routines). One should also be aware of the **«unknown unknowns»** when attempting to mitigate high impact incidents.*

Source: Rystad Energy research and analysis; PTIL

Noise, cold weather stated as forms of poor working environment with most frequent exposure

Offshore oil and gas workers' stated exposure frequency to poor working environment in 2019

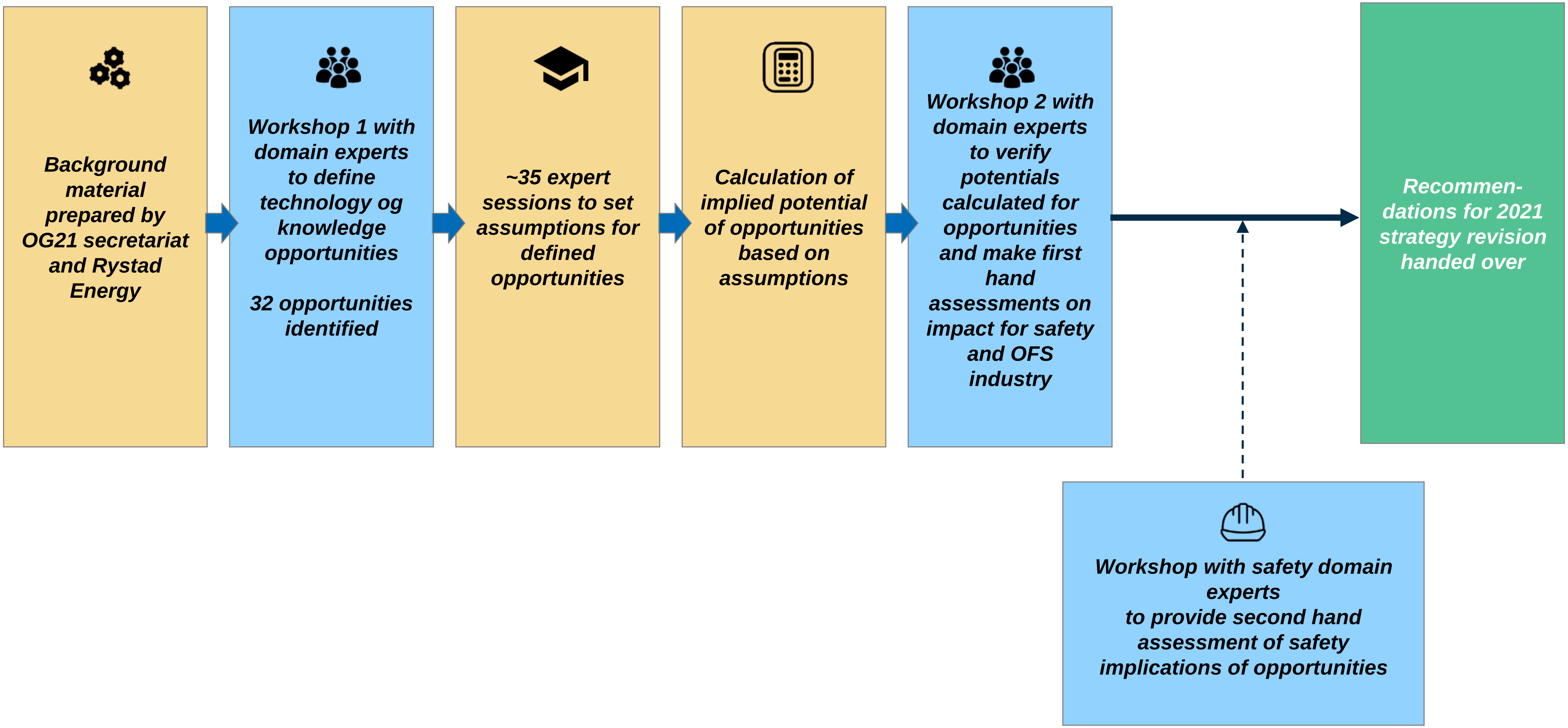


- PTIL's RNNP includes a survey of offshore oil and gas workers' perceived working environment every other year. Workers indicate 5 if they are often exposed to a certain hazard and 1 of they rarely are, with a discrete scale in-between.
- The 2019 report survey answers has all physical, chemical and ergonomic exposures at between 2 and 3. Loud noise and cold weather are the conditions workers are most often exposed to, being almost at level 3.
- A level 1 or 2 on all exposures is not necessarily obtainable without significant investment, meaning the exposures have an «invisible floor» for the kind of value that can be obtained.

Figures from RNNP Sokkelrapport 2019
Source: Rystad Energy research and analysis; PTIL

Report contents

Summary of approach to calculating technology and knowledge opportunity potentials



Background material prepared by OG21 secretariat and Rystad Energy

Workshop 1 with domain experts to define technology og knowledge opportunities

32 opportunities identified

~35 expert sessions to set assumptions for defined opportunities

Calculation of implied potential of opportunities based on assumptions

Workshop 2 with domain experts to verify potentials calculated for opportunities and make first hand assessments on impact for safety and OFS industry

Workshop with safety domain experts to provide second hand assessment of safety implications of opportunities

Recommen-dations for 2021 strategy revision handed over

An opportunity allocated to a certain TG will most likely have some relevance to other TGs

TG 1 Climate change & environment

1. Energy efficiency in offshore operations

2. Offshore carbon capture and storage

3. Environmental risk assessment and management

4. Environmental surveillance and leak detection

5. Oil spill contingency

TG 2 Subsurface understanding

7. Offshore CO2 storage and late-life deposits

8. Data gathering for subsurface applications

8. Data management for subsurface applications

9. Improved subsurface understanding and models

10. Water management

TG 3 Drilling, compl., interv. & P&A

11. Data gathering and optimization of drilling operations

12. Improved drilling equipment

13. Advanced well construction and methodologies

14. Recompletion & multilateral technologies

15. Subsea well intervention technologies

16. Tight and inhomogeneous reservoirs

17. Road to rigless P&A

TG 4 Prod., processing & transport

18. Material condition detection and degradation mechanisms

19. Data gathering for facilities

20. Data management for facilities

21. Digital tools for improved maintenance and more efficient operations

22. Unmanned facilities and subsea tie-backs

23. Standardized subsea templates

TG 5 Safety & working environment

24. Consequences and opportunities from adoption of new technologies

25. Consequences and opportunities from new business models

26. Major accidents: Improved understanding of risk and uncertainty

27. Improved working environment

28. Cyber security as prerequisite for other digitalization technologies

Scope 2 and 3 considerations

Offshore smart grid

New energy markets

Circular economy and life-cycle assessments

While other opportunities are primarily concerned with direct or «scope 1 type» emissions, costs and volumes, opportunities in this category address an industry wide shift towards sustainability. Emphasis is placed on how oil and gas competence can be continued in the face of the energy transition and how a broader scope of emissions can be addressed

Source: Rystad Energy research and analysis

An opportunity allocated to a certain TG will most likely have some relevance to other TGs

**TG 1
Climate change & environment**

1. Energy efficiency in offshore operations

2. Offshore carbon capture and storage

3. Environmental risk assessment and management

4. Environmental surveillance and leak detection

5. Oil spill contingency

**TG 2
Subsurface understanding**

7. Offshore CO2 storage and late-life deposits

8. Data gathering for subsurface applications

8. Data management for subsurface applications

9. Improved subsurface understanding and models

10. Water management

**TG 3
Drilling, compl., interv. & P&A**

11. Data gathering and optimization of drilling operations

12. Improved drilling equipment

13. Advanced well construction and methodologies

14. Recompletion & multilateral technologies

15. Subsea well intervention technologies

16. Tight and inhomogeneous reservoirs

17. Road to rigless P&A

**TG 4
Prod., processing & transport**

18.

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23. Standardized subsea templates

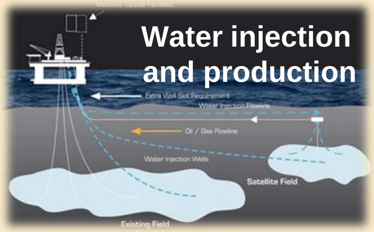
**TG 5
Safety & working environment**

technologies

Scope 2 and 3 considerations

ets

and



- *Relevant to the topic of "Energy optimization" as a significant amount of turbine power is used on water pumps or water production*
- *Clearly relevant for the reservoir related topic of "Effective water injection and management"*
- *Also relevant for TG3 as water production can be partially addressed by improved well completion technology to avoid it reaching topsides in the first place.*

Source: Rystad Energy research and analysis

An opportunity allocated to a certain TG will most likely have some relevance to other TGs

TG 1
Climate change & environment

1. *Energy efficiency in offshore operations*

① ***2. Offshore carbon capture and storage***

3. Environmental risk assessment and management

4. Environmental surveillance and le
detection

5. Oil spill contingency

TG 2
Subsurface understanding

② ***7. Offshore CO2 storage and late-life deposits***

8. Data gathering for subsurface applications

TG 3
Drilling, compl., interv. & P&A

11. Data gathering and optimization of drilling operations

12. Improved drilling equipment

13. Advanced well

TG 4
Prod., processing & transport

18. Material condition detection and degradation mechanisms

19. Data gathering for facilities

TG 5
Safety & working environment

24. Consequences and opportunities from adoption of new technologies

25. Consequences and opportunities from new business

Scope 2 and 3 considerations

Offshore smart grid

④ ***New energy markets***

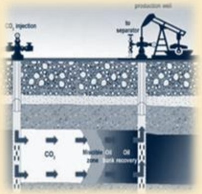
③ ***Circular economy and life-cycle assessments***

Mitigates upstream O&G's scope 1 emissions

Mainly mitigates global emissions, but not upstream's scope 1
(Will still contribute to mitigating net emissions)

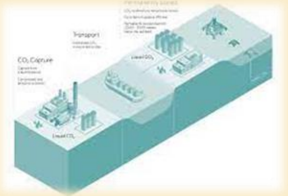
① ***Offshore carbon capture and storage***
Can NCS oil and gas facilities be modified with CCS attachments to reduce direct emissions?

② ***Offshore CO2 storage and late-life deposits***
Can synergies be realized between a 3rd party desire to store emissions and NCS E&P's desire for increased recovery?...



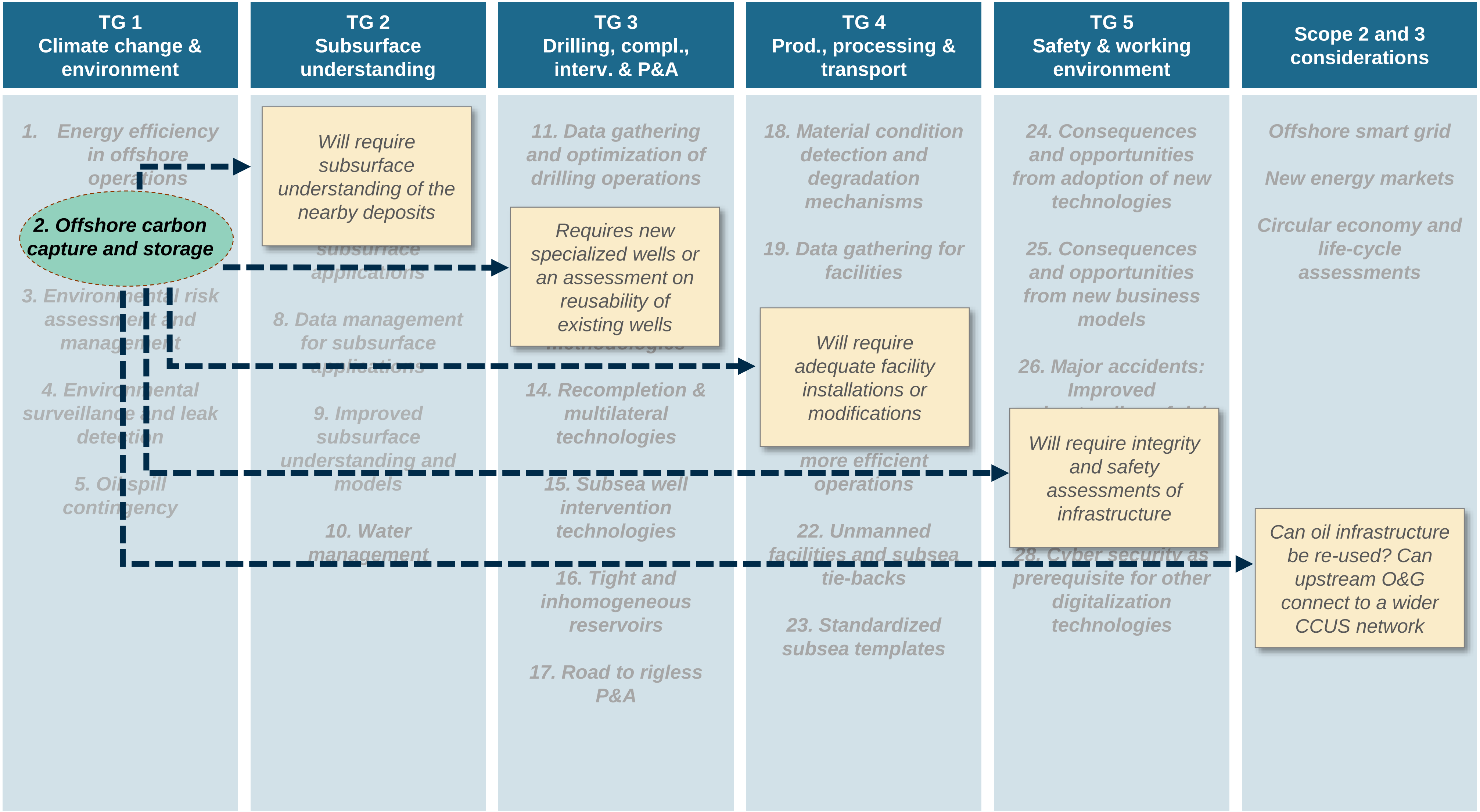
③ **Circular economy**
..if not, can oil and gas fields in the very tail end transition to becoming CCS deposits?

④ **New energy markets**
What are the prospects of CCUS standing on its own feet as a Norwegian industry?



Source: Rystad Energy research and analysis

An opportunity allocated to a certain TG will most likely have some relevance to other TGs



TG 1 Climate change & environment

1. Energy efficiency in offshore operations

2. Offshore carbon capture and storage

3. Environmental risk assessment and management

4. Environmental surveillance and leak detection

5. Oil spill contingency

TG 2 Subsurface understanding

Will require subsurface understanding of the nearby deposits

subsurface applications

8. Data management for subsurface applications

9. Improved subsurface understanding and models

10. Water management

TG 3 Drilling, compl., interv. & P&A

11. Data gathering and optimization of drilling operations

Requires new specialized wells or an assessment on reusability of existing wells

methodologies

14. Recompletion & multilateral technologies

15. Subsea well intervention technologies

16. Tight and inhomogeneous reservoirs

17. Road to rigless P&A

TG 4 Prod., processing & transport

18. Material condition detection and degradation mechanisms

19. Data gathering for facilities

Will require adequate facility installations or modifications

more efficient operations

22. Unmanned facilities and subsea tie-backs

23. Standardized subsea templates

TG 5 Safety & working environment

24. Consequences and opportunities from adoption of new technologies

25. Consequences and opportunities from new business models

26. Major accidents: Improved

Will require integrity and safety assessments of infrastructure

28. Cyber security as prerequisite for other digitalization technologies

Scope 2 and 3 considerations

Offshore smart grid

New energy markets

Circular economy and life-cycle assessments

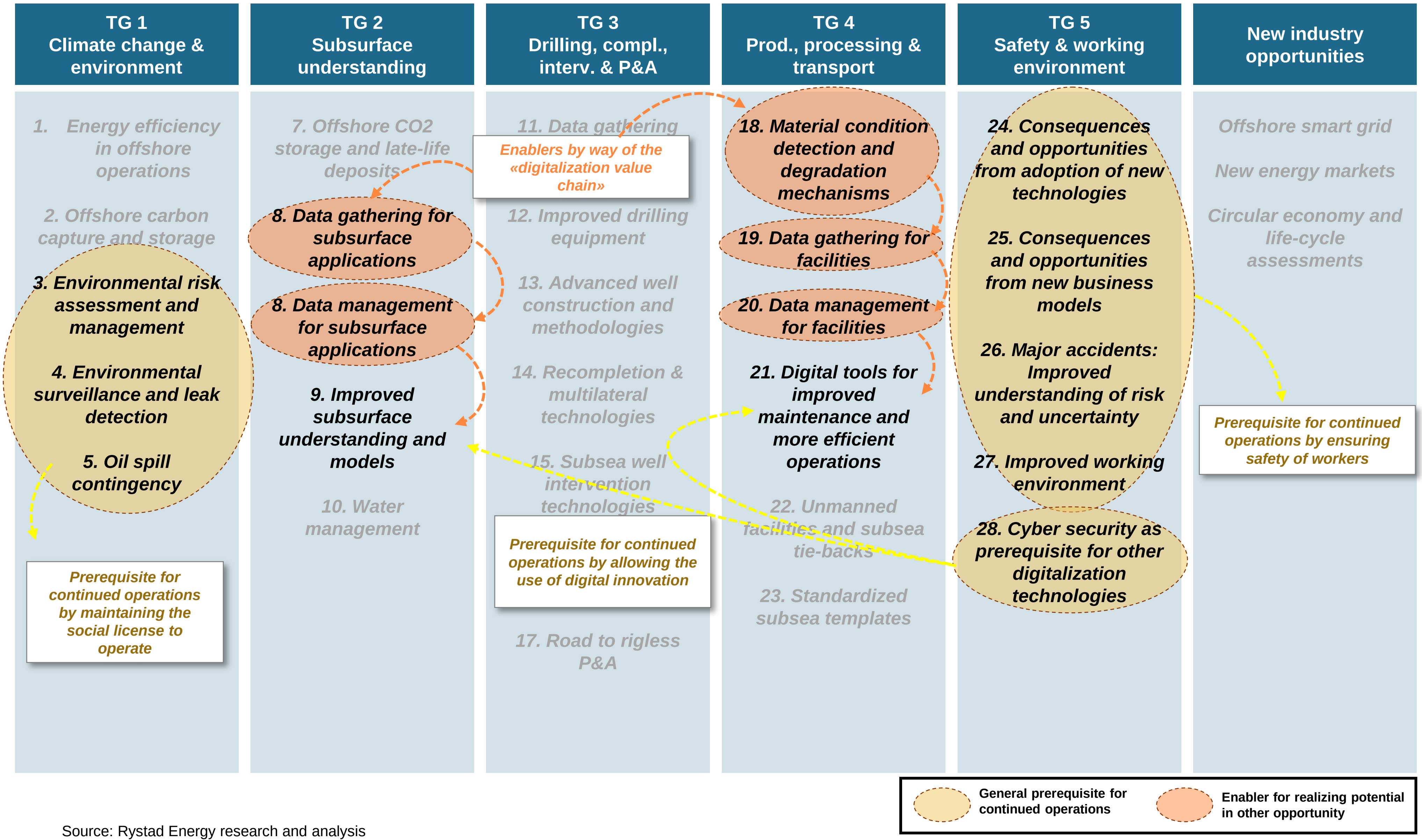
Can oil infrastructure be re-used? Can upstream O&G connect to a wider CCUS network

Source: Rystad Energy research and analysis

Overview of opportunities for each TG and their adjacencies to other TGs

TG	Opportunity name	TG1	TG2	TG3	TG4	TG5
TG1 Climate change and environment	**#1 Energy efficiency in offshore operations**	■	▒	▒	▒	
	#2 Offshore carbon capture and storage	■	▒	▒	▒	▒
	#3 Leak detection and mitigation	■	▒	▒	▒	▒
	#4 Environmental risk assesment and management	■	▒	▒	▒	▒
	#5 Oil spill contingency	■			▒	▒
TG2 Subsurface under-standing	**#6 Offshore CO2 storage and late-life deposits**	▒	■	▒	▒	
	#7 Data gathering for subsurface understanding and models		■	▒		
	#8 Data management for subsurface understanding and models	▒	■	▒	▒	▒
	#9 Subsurface understanding and models	▒	■	▒	▒	
	#10 Water management	▒	■	▒	▒	▒
TG3 Drilling, completions, intervention and P&A	**#11 Data gathering and optimization of drilling operations**		▒	■	▒	▒
	#12 Improved drilling equipment	▒		■		▒
	#13 Advanced well construction and methodologies			■		▒
	#14 Subsea well intervention technologies			■	▒	
	#15 Recompletion & multilateral technologies		▒	■		
	#16 Tight and inhomogenous reservoirs		▒	■	▒	
	#17 More efficient P&A and road to rigless	▒	▒	■		▒
TG4 Production, processing and transport	**#18 Material condition detection and degradation mechanisms**				■	▒
	#19 Data gathering for facilties				■	
	#20 Data management for facilities	▒	▒	▒	■	▒
	#21 Digital tools for improved maintenance and more efficient operations		▒	▒	■	
	#22 Unmanned facilities and subsea tie-backs				■	
	#23 Standardized subsea templates		▒	▒	■	▒
TG5 Safety and working environment	**#24 Consequences and opportunites from adoption of new technologies**	▒	▒	▒	▒	■
	#25 Consequences and opportunites from new business models	▒	▒	▒	▒	■
	#26 Major accidents: Improved understanding of risk and uncertainty	▒	▒	▒	▒	■
	#27 Improved work environment	▒	▒	▒	▒	■
	#28 Cyber security as enabler of other digitalization technologies	▒	▒	▒	▒	■
New industry opportunities (scope 2 & 3)	**Offshore smart grid**	▒			▒	▒
	Circular economy / life cycle assessments	▒	▒	▒	▒	▒
	New energy markets	▒	▒	▒	▒	▒

Some of the opportunities identified are enablers or prerequisites for those with direct effects



TG 1
Climate change & environment

1. Energy efficiency in offshore operations

2. Offshore carbon capture and storage

3. Environmental risk assessment and management

4. Environmental surveillance and leak detection

5. Oil spill contingency

Prerequisite for continued operations by maintaining the social license to operate

TG 2
Subsurface understanding

7. Offshore CO2 storage and late-life deposits

8. Data gathering for subsurface applications

8. Data management for subsurface applications

9. Improved subsurface understanding and models

10. Water management

TG 3
Drilling, compl., interv. & P&A

11. Data gathering

Enablers by way of the «digitalization value chain»

12. Improved drilling equipment

13. Advanced well construction and methodologies

14. Recompletion & multilateral technologies

15. Subsea well intervention technologies

Prerequisite for continued operations by allowing the use of digital innovation

17. Road to rigless P&A

TG 4
Prod., processing & transport

18. Material condition detection and degradation mechanisms

19. Data gathering for facilities

20. Data management for facilities

21. Digital tools for improved maintenance and more efficient operations

22. Unmanned facilities and subsea tie-backs

23. Standardized subsea templates

TG 5
Safety & working environment

24. Consequences and opportunities from adoption of new technologies

25. Consequences and opportunities from new business models

26. Major accidents: Improved understanding of risk and uncertainty

27. Improved working environment

28. Cyber security as prerequisite for other digitalization technologies

New industry opportunities

Offshore smart grid

New energy markets

Circular economy and life-cycle assessments

Prerequisite for continued operations by ensuring safety of workers

General prerequisite for continued operations

Enabler for realizing potential in other opportunity

Source: Rystad Energy research and analysis

Data opportunities form a value chain applicable and relevant across TG groups

The digitalization value chain

	Prerequisite	Enabler *Sensory input*	Enabler *Data and systems*	Application	Effect
TG1	*TG5 – Cyber security as an enabler of other digitalization technologies*	• New digital sensors for environmental surveillance and leak detection • Measurement tools for discharges and better control of emissions	• Data management systems for environmental risk assessments • Analysis tools to improve long-term potential discharges from wells and shared management tools for biodiversity.	• Faster oil spill detection • Faster leak detection • Unmanned/people-less facilities • Visual detection of spills • Subsea leak detection • Detection of small leaks	• People-less operations • Better control of emissions and content of discharge flows • Reducing emissions • Improve environmental impact and safety
TG2		• New data gathering technologies such as new seismic and CSEM • Optimizing data gathering plan – what data, when and at what frequency.	• Data management, infrastructure and crossdisciplinarity work. • Hybrid modelling combining physical models with ML. • 3D distribution of porosity, automatic fault interpretation.	• Better reservoir models resulting in better subsurface understanding. • Improved data flow across departments.	• Less errors • More efficient operations • Better well placement • Most recent knowledge utilized
TG3		• Technologies for optimizing downhole data gathering and transport. • Utilizing real time data when drilling.	• Automation and digitalization to improve efficiently. • Incorporate data from wells to aid the automation and decision support. • Connectivity	• Automated drilling operations • Better understanding of drilling operations. • Improved process understanding of rig operations. • Better models and tools	• Faster, better and safer drilling operations, resulting in increased volumes and reduced cost and emissions.
TG4		• New sensors for detection of vibration, acoustics, sniffers and imagery	• New software using artificial intelligence and machine learning algorithms in data modelling to improve uptime, lifetime extensions and secure integrity • Digital twin tools	• Material condition detection • Condition-based monitoring on e.g. electrical cables • Risk-based monitoring, inspection and maintenance • Autonomous operations	• Better understanding of material condition and degradation mechanisms • Improved planning and performing of maintenance, less downtime
TG5		• Sensoring of integrity issues or potential hydrocarbon leaks • Sensory to perceive impending collisions between vessels and structures • Sensory to provide access to remote areas of facilities	• Software to improve situational awareness • Artificial intelligence to detect integrity breaches before they occur • Software for better overview of vessels to prevent collision	• Increased situational awareness • Continuous and improved leak and integrity detection • Increased overview of and routing of offshore vessels	• Better crisis management • Fewer collisions • Less human exposure to leaks or integrity issues

Source: Rystad Energy research and analysis

Overview of opportunities and labeling as first order effect or enabler/prereq./macro implicator

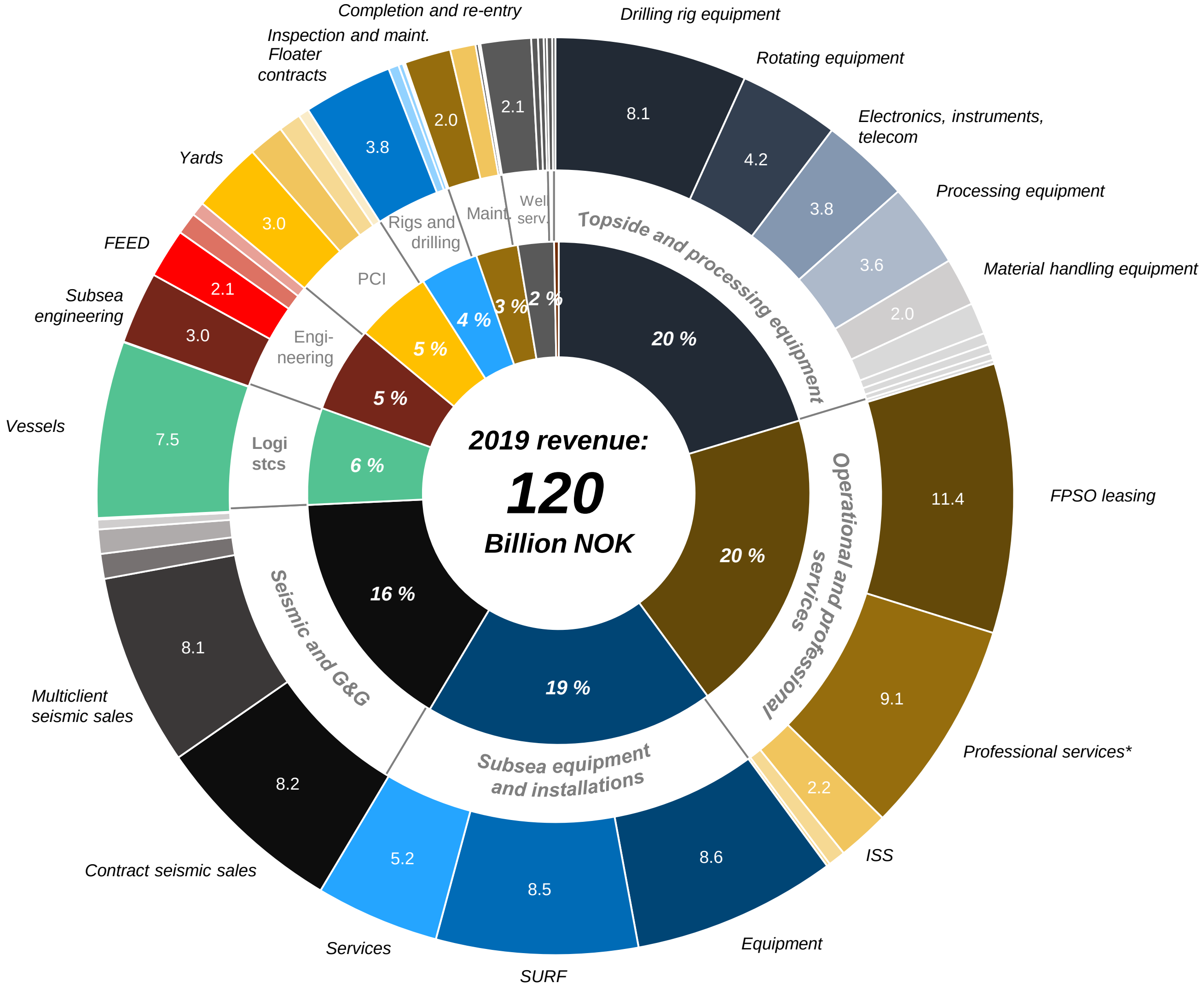
TG	Opportunity name	Approach
TG1 Climate change and environment	#1 Energy efficiency in offshore operations	First order effects
	#2 Offshore carbon capture and storage	First order effects
	#3 Leak detection and mitigation	Pre-requisite
	#4 Environmental risk assesment and management	Pre-requisite
	#5 Oil spill contingency	Pre-requisite
TG2 Subsurface under-standing	#6 Offshore CO2 storage and late-life deposits	First order effects
	#7 Data gathering for subsurface understanding and models	Enabler
	#8 Data management for subsurface understanding and models	Enabler
	#9 Subsurface understanding and models	First order effects
	#10 Water management	First order effects
TG3 Drilling, completions, intervention and P&A	#11 Data gathering and optimization of drilling operations	First order effects
	#12 Improved drilling equipment	First order effects
	#13 Advanced well construction and methodologies	First order effects
	#14 Subsea well intervention technologies	First order effects
	#15 Recompletion & multilateral technologies	First order effects
	#16 Tight and inhomogenous reservoirs	First order effects
	#17 More efficient P&A and road to rigless	First order effects
TG4 Production, processing and transport	#18 Material condition detection and degradation mechanisms	Enabler
	#19 Data gathering for facilties	Enabler
	#20 Data management for facilities	Enabler
	#21 Digital tools for improved maintenance and more efficient operations	First order effects
	#22 Unmanned facilities and subsea tie-backs	First order effects
	#23 Standardized subsea templates	First order effects
TG5 Safety and working environment	#24 Consequences and opportunites from adoption of new technologies	Pre-requisite
	#25 Consequences and opportunites from new business models	Pre-requisite
	#26 Major accidents: Improved understanding of risk and uncertainty	Pre-requisite
	#27 Improved work environment	Pre-requisite
	#28 Cyber security as enabler of other digitalization technologies	Pre-requisite
New industry opportunities (scope 2 & 3)	Offshore smart grid	Broader industry implications
	Circular economy / life cycle assessments	Broader industry implications
	New energy markets	Broader industry implications

Topside/proc. equipment, subsea, prof. services and seismic most exporting OFS segments

- Norwegian OFS had about 397 billion NOK in revenues in 2019. ~30% of this was made by way of exported goods or services
- The chart to the right breaks down these ~30% into 10 main segments and their subsegments.
- The largest segment is «Topside and processing equipment»
- «Operational and professional services», «Subsea equipment and installations» and «Seismic and G&G» are all segments that make up similarly large portions.
- The top four segments account for about 75% of the total revenue, indicating that Norwegian suppliers have especially high international competence in these domains.
- **This is reflected in the list of the top 20 companies in terms of 2019 international revenue:**

VARD a Fincantieri company
ABB
KONGSBERG
DEEPOCEAN
WÄRTSILÄ
AkerSolutions
DNV·GL
TechnipFMC
NOV
SOLSTAD FARSTAD
PGS
JOTUN
ODFJELL DRILLING
DOF
SIEM OFFSHORE CONTRACTORS
Schlumberger
magseis fairfield
AKASTOR

Norwegian OFS 2019 international revenue by segment and subsegment (top 20 subsegments highlighted)
Percent or billion NOK



*Includes HSE and classing services
Source: Rystad Energy research and analysis

Report contents

No silver bullet, a wide range of technologies needed to improve NCS competitiveness

TG	Opportunity name	Volume additions potential [mmboe 2020-2050]	Cost reduction potential [BUSD 2020-2050]	Upstream emissions reduction potential [mt CO2 2020-2050]
TG1 Climate change and environment	#1 Energy efficiency in offshore operations	*Neutral*	5.2	29.0
	#2 Offshore carbon capture and storage	*Neutral*	-9.0	35.0
	#3 Leak detection and mitigation	*Prerequisite for continued operations and future technology adoption*		
	#4 Environmental risk assesment and management			
	#5 Oil spill contingency			
TG2 Subsurface under-standing	#6 Offshore CO2 storage and late-life deposits	495	-13.0	*Very large, but scope 2&3*
	#7 Data gathering for subsurface understanding and models	*Enabler for technology opportunity #9*		
	#8 Data management for subsurface understanding and models			
	#9 Subsurface understanding and models	2560	10.0	1.5
	#10 Water management	1090	0.0	7.0
TG3 Drilling, completions, intervention and P&A	#11 Data gathering and optimization of drilling operations	1550	5.8	1.3
	#12 Improved drilling equipment	0	6.0	2.5
	#13 Advanced well construction and methodologies	840	4.4	0.9
	#14 Subsea well intervention technologies	1520	4.2	0.9
	#15 Recompletion & multilateral technologies	1350	7.0	0.6
	#16 Tight and inhomogenous reservoirs	970	-7.8	-1.9
	#17 More efficient P&A and road to rigless	*Neutral*	5.9	0.6
TG4 Production, processing and transport	#18 Material condition detection and degradation mechanisms	*Enabler for technology opportunity #21*		
	#19 Data gathering for facilties			
	#20 Data management for facilities			
	#21 Digital tools for improved maintenance and more efficient operations	970	20.0	16.5
	#22 Unmanned facilities and subsea tie-backs	800	11.0	1.5
	#23 Standardized subsea templates	710	14.6	*Neutral*
TG5 Safety and working environment	#24 Consequences and opportunites from adoption of new technologies	*Prerequisite for continued operations and future technology adoption*		
	#25 Consequences and opportunites from new business models			
	#26 Major accidents: Improved understanding of risk and uncertainty			
	#27 Improved work environment			
	#28 Cyber security as enabler of other digitalization technologies	*Prerequisite for digitalization technologies*		
New industry opportunities (scope 2 & 3)	Offshore smart grid	*See seperate evaluation*		
	Circular economy / life cycle assessments			
	New energy markets			

Source: Rystad Energy research and analysis

Opportunities mostly recommended based on calc.s of potentials, yet with three exceptions

TG	Opportunity name	Advised role in strategy revision	
TG1 Climate change and environment	**#1 Energy efficiency in offshore operations**	🟩	Large emission reduction potential and positive cost contribution
	#2 Offshore carbon capture and storage	🟩	Likely needed to reach long term emissions targets, but challenging topside conditions
	#3 Leak detection and mitigation	🟩	Prerequisite for continued operations and social lisence to operate
	#4 Environmental risk assesment and management	🟩	Prerequisites for continued operations, failure with potentially devastating effect on social lisence to operate
	#5 Oil spill contingency	🟩	
TG2 Subsurface under-standing	**#6 Offshore CO2 storage and late-life deposits**	🟨	Refocus to be a part of cessation plans. 3rd party CO2 shippers unlikely to approve EOR applications
	#7 Data gathering for subsurface understanding and models	🟩	Enabler for unlocking increasingly elusive NCS volumes through faster and better modelling and understanding. Largest volume contribution in list and with positive cost contribution
	#8 Data management for subsurface understanding and models	🟩	
	#9 Subsurface understanding and models	🟩	
	#10 Water management	🟩	Adresses one of the largest sources of turbine power on NCS. Considerable emissions impact
TG3 Drilling, completions, intervention and P&A	**#11 Data gathering and optimization of drilling operations**	🟩	Positive contribution on all primary effects (volumes, costs, emissions), highly brownfield relevant
	#12 Improved drilling equipment	🟩	Beyond moderate positive effect on costs and emissions a high contribution to safety is expected
	#13 Advanced well construction and methodologies	🟩	Positive contribution on all primary effects (volumes, costs, emissions), highly brownfield relevant
	#14 Subsea well intervention technologies	🟩	Opens door for fast, cheap increases in production in existing and future fields
	#15 Recompletion & multilateral technologies	🟩	More efficient well construction gives modest volume and cost benefits
	#16 Tight and inhomogenous reservoirs	🟥	Positive volume impact, but at the expense of higher cost and more emissions than other volumes
	#17 More efficient P&A and road to rigless	🟩	Increases cost efficiency of pending ncs P&A commitment
TG4 Production, processing and transport	**#18 Material condition detection and degradation mechanisms**	🟩	Enabler prolonged life of fields as safety and integrity is ensured
	#19 Data gathering for facilties	🟩	Enabler for further digitalization of NCS facilities and remaining competitive on opex/safety
	#20 Data management for facilities	🟩	
	#21 Digital tools for improved maintenance and more efficient operations	🟩	Largest cost contribution from single opportunity given prospective reduced maintenance scope
	#22 Unmanned facilities and subsea tie-backs	🟩	Allows for developments not feasible today: restraints related to economics/distance alleviated
	#23 Standardized subsea templates	🟨	Sizable potential, yet limited scale of subsea industry draws prospect of cost savings into question
TG5 Safety and working environment	**#24 Consequences and opportunites from adoption of new technologies**	🟩	Prerequisites for continued operations and social license to operate and enabler for adoption of other digitalization technologies.
	#25 Consequences and opportunites from new business models	🟩	
	#26 Major accidents: Improved understanding of risk and uncertainty	🟩	
	#27 Improved work environment	🟩	
	#28 Cyber security as enabler of other digitalization technologies	🟩	
New industry opportunities (scope 2 & 3)	**Offshore smart grid**	🟩	Pathway to reaching upstream emission targets by leveraging new energy and storage solutions
	Circular economy / life cycle assessments	🟩	Sizable potential, especially related to the re-use of wells for other well intensive industries
	New energy markets	🟩	Competence overlaps with O&G, will be vital to secure the longevity of the Norwegian offshore industry

Source: Rystad Energy research and analysis

Summary of technology opportunities and example technologies (1/2)

TG	Opportunity name	Description	Approach	Example technologies
TG1 Climate change and environment	**#1 Energy efficiency in offshore operations**	*Energy efficiency technologies to reduce total energy consumption and emissions offshore*	⚙ First order effects	- Low-emission drainage strategy - Increased efficiency of local power generation - Low- and zero carbon fuels
	#2 Offshore carbon capture and storage	*Small-scale carbon capture topside to reduce turbine emissions*	⚙ First order effects	- Compact topside capture technologies - CO2 injection - Offshore blue hydrogen production
	#3 Leak detection and mitigation	*Control of discharges and environmental impact with digital sensory, data analytics and modelling software*	✓ Pre-requisite	- Sensors - AUVs and drones - ML, data analytics and modelling tools for leak detection
	#4 Environmental risk assesment and management	*Control of environmental risk assessment and management using digital tools and modelling software*	✓ Pre-requisite	- Net Environmental Benefit Analysis tools - Industry standard discharge tools - Environmental risk management tools
	#5 Oil spill contingency	*Maintaining social license to operate by adopting new technologies to reduce risk in case of oil releases*	✓ Pre-requisite	- SSDI & SSMI - Winterized equipment - Oil spill modelling tools
TG2 Subsurface understanding	**#6 Offshore CO2 storage and late-life deposits**	*CO2 injection of 3rd party CO2 emissions for enhanced oil recovery*	⚙ First order effects	- Anti-corrosive processing equipment - CO2 injection pump technologies - Long-term reservoir monitoring capabilities
	#7 Data gathering for subsurface understanding and models	*Data management systems and infrastructure, new modelling approaches and data flow*	✓ Enabler	- High resolution broadband seismic data - OBN acquisition/streamer systems - 3D resistivity imaging
	#8 Data management for subsurface understanding and models	*Technologies and knowledge that improves the input that goes into the models*	✓ Enabler	- Data management protocols and maintenance systems - Cuttings database - Improved tectonic models
	#9 Subsurface understanding and models	*Improved reservoir models as a result of input and processes, leading to more efficient and accurate operations*	⚙ First order effects	- Enhanced knowledge of seal, overburden and chemical composition etc.
	#10 Water management	*Improved water management for reduced emissions and increased recovery*	⚙ First order effects	- EOR measures (foams, polymers, gels etc.) - Improved inflow control devices - Effective green chemicals
TG3 Drilling, completions, intervention and P&A	**#11 Data gathering and optimization of drilling operations**	*New sensory input and improved data systems, resulting in more efficient operations*	⚙ First order effects	- Automation through next generation sensors - Robotization - Wired-pipe with downhole power supply
	#12 Improved drilling equipment	*Improved drilling equipment such as improved BoP and hybrid technologies*	⚙ First order effects	- Electric BOP - Hybrid technologies and batteries - Energy management systems
	#13 Advanced well construction and methodologies	*Technologies and knowledge associated with improved well construction*	⚙ First order effects	- MPD technologies - Simulation methodologies - Rotating control device technologies

⚙ First order effects ✓ Pre-requisite 💡 Broader industry applications ✓ Enabler

Source: Rystad Energy research and analysis

Summary of technology opportunities and example technologies (2/2)

TG	Opportunity name	Description	Approach	Example technologies
TG3 Drilling, completions, intervention and P&A	**#14 Subsea well intervention technologies**	*Subsea well intervention technologies to reduce cost and increase safety*	⚙ First order effects	• Simpler standardized well intervention systems • Remote on seafloor devices and technologies
	#15 Recompletion & multilateral technologies	*Technologies associated with better utilization of existing wells*	⚙ First order effects	• Multi-lateral technologies • Technologies for side-tracking and retrofitting • Further develop AICD, TTRD, CTD
	#16 Tight and inhomogenous reservoirs	*Technologies for recovering tight and/or inhomogeneous reservoirs*	⚙ First order effects	• Improved completion technologies and stimulation • Multi-branch wells with fracking in each branch • New fracking methods
	#17 More efficient P&A and road to rigless	*Enabling rigless P&A on the NCS*	⚙ First order effects	• Metal plugging techniques • Tubing slicing via wireline/micro-tube removal
TG4 Production, processing and transport	**#18 Material condition detection and degradation mechanisms**	*Improved knowledge and understanding of material condition detection and degradation mechanisms*	✓ Enabler	• Software tools for material conditioning and degradation analysis • Detection of corrosion under insulation
	#19 Data gathering for facilties	*Adoption of digital tools for improved monitoring and introduction of condition-based maintenance*	✓ Enabler	• Drones and AUVs for autonomous inspections • Digital densory for monitoring and detection
	#20 Data management for facilities	*Adoption of new sensory technologies for people-less operations and improved monitoring*	✓ Enabler	• Software for communication between sensors and different platforms • Standardized communication protocols
	#21 Digital tools for improved maintenance and more efficient operations	*Adoption of data management tools to improve integrity monitoring an maintenance planning*	⚙ First order effects	• Digital twin • Analytics for integrity monitoring • Software for maintenance planning
	#22 Unmanned facilities and subsea tie-backs	*Flow assurance technologies to increase technically possible tie-back distances*	⚙ First order effects	• Extended reach for multiphase transport • Subsea separation technologies • Remote operations
	#23 Standardized subsea templates	*Standardization of subsea modules to reduce development cost and shorten lead time*	⚙ First order effects	• Standardized subsea equipment modules • Standardized subsea sensory • Standardized test and qualification runs
New industry opportunities (scope 2 & 3)	**Offshore smart grid**	*Interconnecting oil and gas installations with other energy systems to electrify and economize power consumption*	💡 Broader industry implications	• Long-distance HVAC, HVDC through turrets • Energy storage opportunities • Integration of renewable energy sources
	Circular economy / life cycle assessments	*New energy markets with the ability to offset decline in O&G spending*	💡 Broader industry implications	• Life cycle assessment tools • Net lifetime carbon footprint analysis • Late-life deposits
	New energy markets	*Comparisons between scope 1 emissions and footprint of procured materials/components*	💡 Broader industry implications	• Blue hydrogen with carbon capture and storage • Offshore wind • Marine minerals

⚙ First order effects ✓ Pre-requisite 💡 Broader industry applications ✓ Enabler

Source: Rystad Energy research and analysis

Summary of targeted volumes, costs and emissions, and related assumptions/effects (1/2)

Only technology opportunities with first order effects in the table

TG	Opportunity name	Volumes		Cost		Emissions	
		Target*	Assumptions	Target*	Assumptions	Target*	Assumptions
TG1 Climate change and environment	**#1 Energy efficiency in offshore operations**	64%	- Targets electrified and non-electrified producing fields	17%	- Power cost reduction on electrified fields - Increased gas sales on non-electrified	75%	- Targets turbine emissions in all fields
	#2 Offshore carbon capture and storage	10%	- Targets brownfield and greenfield FPSOs	4%	- Will lead to a cost increase in facility capex due to the topside CCS module	23%	- Targets turbine emissions in selected fields
TG2 Subsurface under-standing	**#6 Offshore CO2 storage and late-life deposits**	41%	- Targets volumes of larger oil fields using water as drive method which has more than 10y left of production	16%	- Expected to increase facility and recompletion costs		- 3rd party emissions
	#9 Subsurface understanding and models	57%	- Targets volumes from new wells	21%	- Potential to reduce exploration, drilling and well costs	6%	- Targets drilling emissions from rigs
	#10 Water management	49%	- Targets volumes from oil fields using water drive as recovery method	8%	- Potential to reduce brownfield capex by reducing chances of water break-through	64%	- Potential to reduce turine emissions in larger oil fields by improving water management
TG3 Drilling, completions, intervention and P&A	**#11 Data gathering and optimization of drilling operations**	58%	- Targets volumes from new wells	19%	- Targets development and infill drilling costs as value from exploration wells have limited effect	5%	- Targets drilling emissions from rigs
	#12 Improved drilling equipment	58%	- Targets volumes from new wells	19%	- Potential to reduce time-dependent well costs and costs related to drilling mud and hydraulic fluids	5%	- Targets drilling emissions from rigs
	#13 Advanced well construction and methodologies	36%	- Targets larger depleted oil fields	19%	- Development well costs especially targeting to improve well construction	5%	- Targets drilling emissions from rigs, especially relevant for infill drilling

*Target share of total forecasted volumes, costs and emissions from 2022-2050

Source: Rystad Energy research and analysis

Summary of targeted volumes, costs and emissions, and related assumptions/effects (2/2)

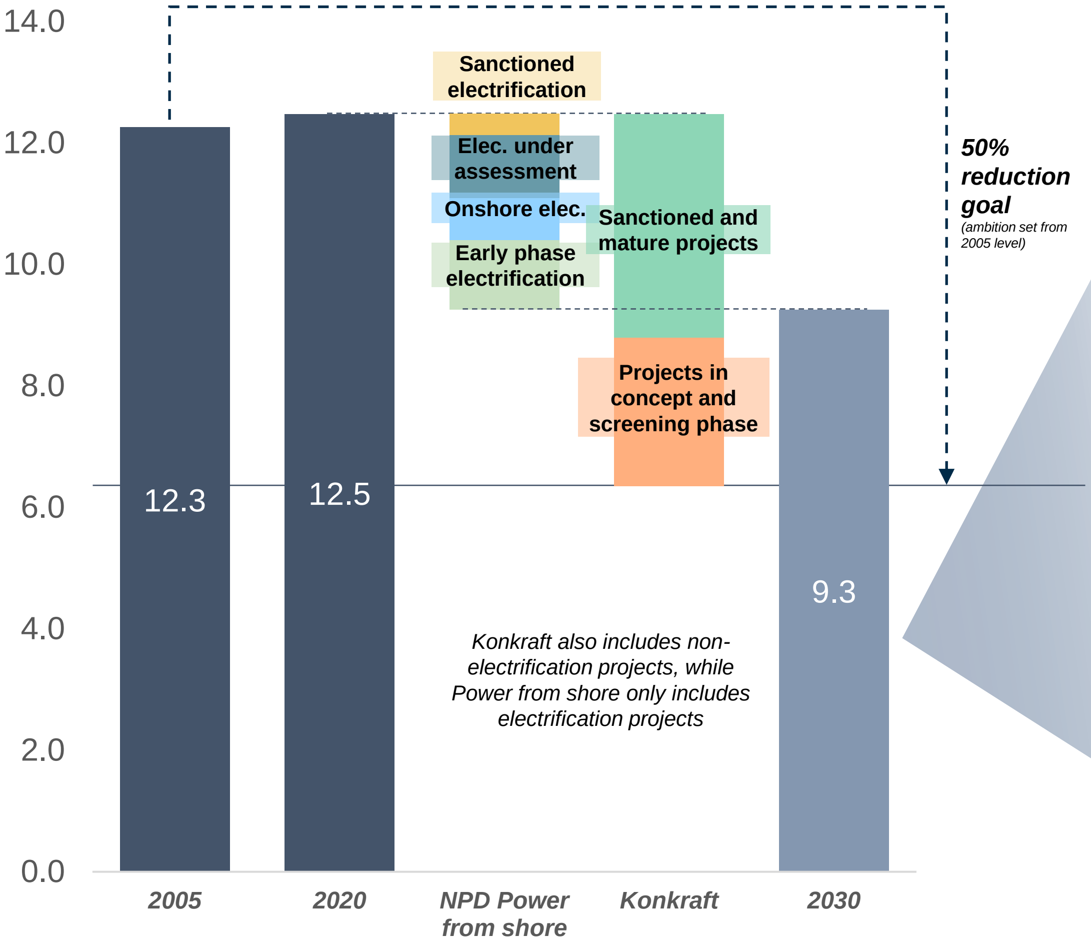
Only technology opportunities with first order effects in the table

		Volumes		Cost		Emissions	
TG	**Opportunity name**	**Target***	**Assumptions**	**Target***	**Assumptions**	**Target***	**Assumptions**
TG3 Drilling, completions, intervention and P&A	**#14 Subsea well intervention technologies**	61%	- *Targets volumes from subsea completed wells*	13%	- *Targets well costs associated to development*	5%	- *Targets drilling emissions from rigs*
	#15 Recompletion & multilateral technologies	49%	- *Potential improvements from better utilization of existing wells and new well targets in larger oil fields*	11%	- *Brownfield drilling cost is addressed*	2%	- *Targets drilling emissions related to brownfield drilling at oil fields*
	#16 Tight and inhomogenous reservoirs	35%	- *Target volumes are tight reservoirs*	19%	- *Targets well and well construction costs* - *Likely to be costly even if well capex is reduced*	5%	- *Tight reservoirs are typically more emission intensive than the average*
	#17 More efficient P&A and road to rigless	0%	- *Neutral*	3%	- *Potential to reduce P&A cost*	1%	- *May reduce rig emissions during P&A*
TG4 Production, processing and transport	**#21 Digital tools for improved maintenance and more efficient operations**	100%	- *Applicable to all fields*	20%	- *Targeting maintenance costs, in addition to parts, equipment and offshore manning*	8%	- *Can reduce flaring during planned and unplanned maintenance*
	#22 Unmanned facilities and subsea tie-backs	5%	- *Future smaller developments outside existing tie-back reach* - *May open new exploration potential near-field*	4%	- *Can reduce facility capex both greenfield and brownfield for smaller developments* - *Further upside potential in unmanned facilities*	15%	- *May reduce power consumption with subsea processing, but main intention is to boost recovery*
	#23 Standardized subsea templates	31%	- *Future subsea tie-back developments*	14%	- *Future subsea tie-back developments* - *Reducing facility capex*	0%	- *Neutral*

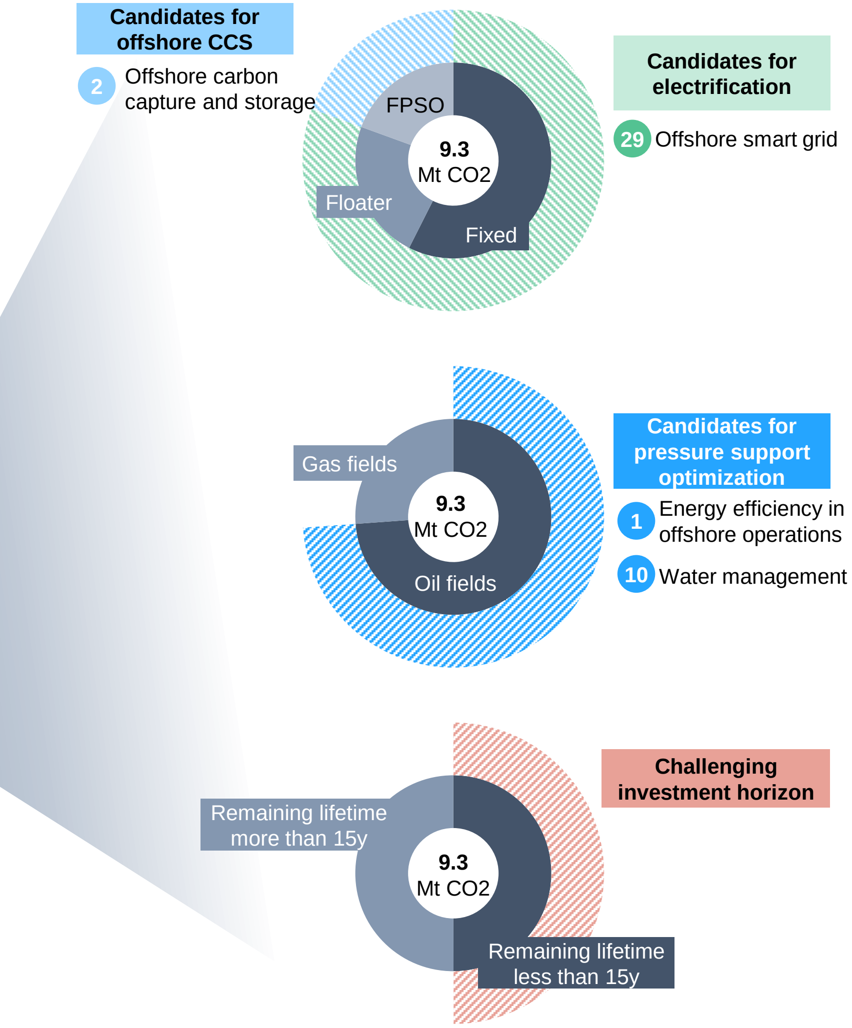
*Target share of total forecasted volumes, costs and emissions from 2022-2050
Source: Rystad Energy research and analysis

About 25% gap of unidentified projects to reach emission reduction goal

Upstream emission volumes on the NCS*
Million tons CO2



Technology opportunities
(split by 2020 upstream emissions)



*Includes onshore emissions and flaring
Source: Rystad Energy UCube; NPD's Power from shore report; Konkraft

Offshore CO2 storage and late-life deposits:
Could end-of-life CO2 storage be a more viable pathway than CO2 for EOR?

CO2 for EOR and late life deposits

CO2 suppliers from the European industry are negative to be associated with enhanced oil recovery, large infrastructure investments are needed and modifications on existing wells and processing equipment is expensive.

Could end-of-life CO2 storage be a more viable pathway than CO2 for EOR?

Utilize existing wells for CO2 injection to save well construction and P&A cost	• CO2 storage through legacy wells in depleted oil and gas fields could be a more cost-effective solution to store CO2, saving well construction and P&A cost. • If existing injection wells could be used, all well costs associated with CO2 injection could be saved. Existing injection wells might handle 2-3 years of CO2 injection after field shutdown without further modifications against corrosion. • Due to regulations, operators must monitor oil and gas reservoirs for a period after field shutdown to assure the reservoirs are not leaking. This monitoring could be combined with required monitoring of the CO2 storage reservoir.
Create a standardized subsea solution for CO2 injection prior to field abandonment	• Standardization of subsea injection modules could reduce costs of installing necessary infrastructure to handle CO2 injection. • CO2 carriers could deliver CO2 directly to injection templates. • Standardized subsea solutions could be moved from well to well and field to field, gradually filling up reservoirs at the end of a fields' lifetime.
Positive economics in the decom phase	• Using existing oil and gas fields as CO2 storage after field shutdown could improve the end-of-life economics of a field significantly – both delaying decom and getting revenue from CO2 handling and storage. CO2 storage could add significant economic value to a late-life oil and gas field. Equinor has signalized cost of CO2 transportation and storage in saline aquifers could cost 35-55 EUR/ton CO2 in 2030, but using depleted oil and gas fields with legacy wells could reduce costs significantly avoiding well costs.
A way to get to net-zero for operators only focusing on oil and gas?	• This could be an alternative business model for oil and gas operators to get to net-zero without investing in the renewable energy industry. • EU taxonomy does not leave the door open for CO2 EOR, as no relation to the oil and gas industry and increased recovery is accepted as a green method to store CO2 emissions. • This pathway is maintaining social license to operate, since no increase of oil and gas production is associated to the CO2 storage – in contrary to CO2 EOR.

Source: Rystad Energy research and analysis;

Is the subsea industry too small to standardize?

Subsea XMTs

Number added in 2020

305

From 5-6 suppliers:

AkerSolutions OneSubsea TechnipFMC BAKER HUGHES DRIL QUIP

Globally

Offshore wind turbines

Number added in 2020

~1200

Mainly in Europe & China

Onshore wind turbines

Number added in 2020

~20 000

Globally

Solar PV

Number added in 2020

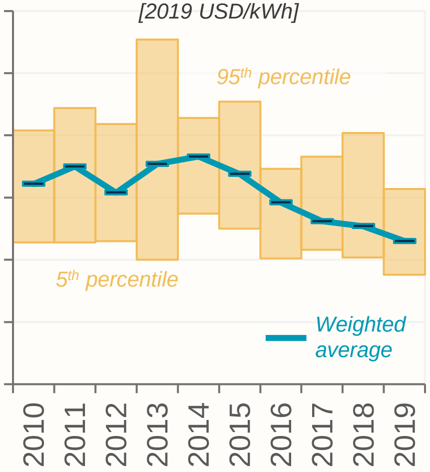
~150 million

Globally

- Are ~300 units yearly enough to support standardization?
- The subsea industry is far from the scale seen in the renewable industry segments where standardization is used to drive costs down.
- Are there alternatives to standardization of equipment modules which can lead to shorter lead time and cost reductions?
- Alternatives could be 3D printing, digitalized reserve part library, standardized qualification runs and measurement methods.

Industrialization driving cost reductions

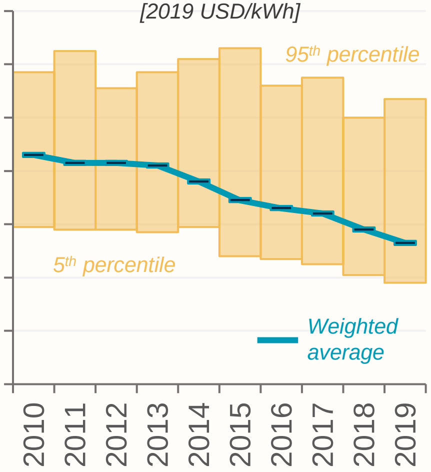
Levelized cost of electricity (LCOE) [2019 USD/kWh]



2010-2019 change:

-29%

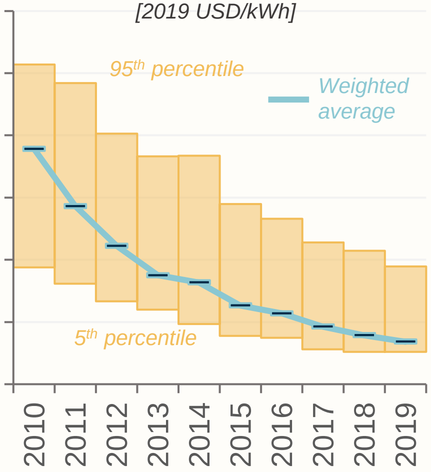
Levelized cost of electricity (LCOE) [2019 USD/kWh]



2010-2019 change:

-38%

Levelized cost of electricity (LCOE) [2019 USD/kWh]



2010-2019 change:

-82%

Source: Rystad Energy research and analysis; SubseaCube; RenewablesCube; OffshoreWindCube; IRENA (2020): *Renewable Power Generation Costs in 2019*

Report contents

Offshore smart grid

Description

- An offshore smart grid in a broader term can be seen as interconnecting oil and gas installations and potentially offshore wind installations, battery storage systems, hydrogen production etc. in an offshore area with a completely interconnected smart-grid both having the possibility to distribute power, but also exporting power to shore.
- In a smaller term, smarter offshore electrification strategies by electrifying a hub like Utsira High or interconnecting a hub of offshore oil and gas installations with an offshore wind park could also be viewed as an offshore smart grid.
- Hub solutions could be significantly cheaper to install in terms of cost, but also in terms of carbon footprint.
- An interconnected grid could also solve intermittency issues by having better redundancy options available and as such improving power security.
- Energy storage systems can secure available power for peak periods and different continuous load solutions could be included for better exploitation of the system.
- Power from shore solutions has raised socio-political discussions over the latest year while offshore smart grid solutions could enable electrification solutions without use of power from shore.

The modular Hub-and-Spoke concept is a technically feasible solution that can adapt to specific design requirements. The consortium is well placed to develop, build and operate Hub-and-Spoke projects.

How smart grid solutions could solve current electrification challenges:

- Brownfield electrification of FPSOs is a challenge as older turrets are not suited for high voltage electrification. Cost of changing the turret is high and requires production stops for at least 1 year. Smart grid solutions could make it possible to extract low-voltage electricity to electrify older FPSOs and the low-voltage could also solve intermittency issues.
- Abatement cost of electrification on late-life fields is highly challenging, as many installations on the NCS are post peak. Smart grid solutions allowing to take advantage of the infrastructure for exporting power after the end-of-life of oil and gas installations in an area could bring abatement costs of electrifying late-life fields down to an acceptable level. Interconnections with renewable energy could bring potential revenue in the future.
- Other complicating factors for electrification solutions could be remaining lifetime, frequency differences (50 Hz vs 60 Hz) and long distances from shore.
- A challenge, whether considering electrification from shore or offshore smart grid projects, will be to get all partners in a license to align on a large investment.

Example technologies

- Long-distance HVAC and wet design high voltage cables
- Subsea electrical equipment
- Dynamic HVDC cable
- HVDC through turrets
- Integration of renewable energy sources
- Energy storage opportunities

Source: Rystad Energy research and analysis; OG21 TG1 Workshop; IEA (Picture)

Offshore smart grid: Large potential for synergies through the energy value chain

Offshore smart grid

Electrification at lower cost

- Electrification of hubs and coordinated electrification projects have the potential to reduce costs of electrifying oil and gas installations by 43%* by optimization of grid infrastructure – saving cable and installation costs.
- Coordinated electrification and grid infrastructure projects with the offshore wind industry will also save infrastructure costs for the offshore wind industry, while reducing CO2 footprint from the oil and gas industry. Increased gas sales can also be a positive effect.
- Optimized grid infrastructure will also lower the total carbon footprint with less cables installed.

Competitiveness of Norwegian supplier industry

- The Norwegian supplier industry are already world leading on offshore electrification. Examples are HVAC cable technology and installation.
- Coordinating forces between energy industries can help Norwegian oil and gas suppliers to gain a competitive edge within the offshore wind industry, using existing technology and knowledge from the oil and gas industry to solve technical issues.

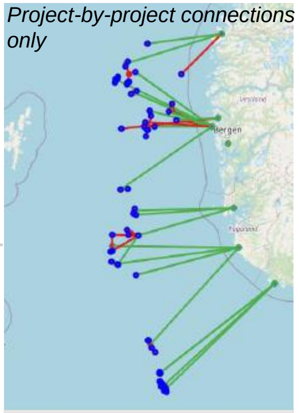
Potential to help industrialization of floating offshore wind

- By coordinating projects between the offshore energy industries, electrification of oil and gas platforms can contribute to industrialization of floating offshore wind.
- Norwegian suppliers are very well positioned to reap the benefits of the industrialization of floating offshore wind.
- Using offshore wind to electrify oil and gas platforms is an alternative to power from shore, which is not dependent of available capacity on the Norwegian onshore power grid. Interconnections to shore can solve intermittency issues and provide excess power to the onshore grid.

Coordination needs between energy value chains

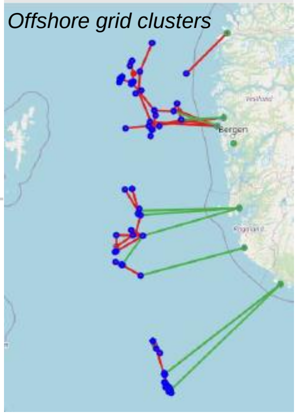
- There would be obvious benefits for both industries by coordinating forces across the energy value chain to drive reduction of CO2 emissions and industrialization of offshore wind.
- Offshore wind also has large potential as an export industry for Norway, with potential to replace declining oil and gas revenues.
- Gassco is a good example of successful coordination of gas export infrastructure, assuring safety and efficiency.

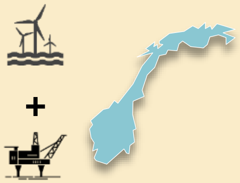
Project-by-project connections only



VS

Offshore grid clusters





Norway has large potential to be a global catalyst for commercialization of floating offshore wind, and at the same time launching an alternative path to electrification and CO2 reducing measures in the offshore oil and gas industry. An offshore smart grid, coordinating projects within the offshore energy value chain would have large potential to reduce costs and improve project economies both for the oil and gas industry and the offshore wind industry.

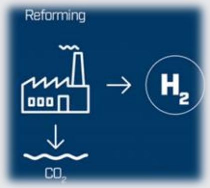
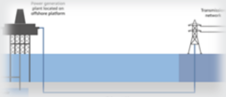
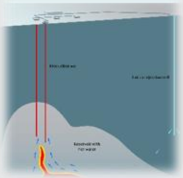
*Analyses by SINTEF/Low Emissions Centre

Source: Rystad Energy research and analysis; SINTEF (Illustrations)

Report contents

The potential for four out of seven new energy markets has been assessed

New energy markets

1 **Hydrogen**	2 **CCS**	3 **Offshore wind**	4 **Marine minerals**	5 **Low-carbon fuels**	6 **Offshore gas to wire**	7 **Geothermal**
						

Assessed

with the goal of determining potential to offset long term decline in oil and gas spending. Examples are synergized in a low carbon scenario.

Several overlaps in competence between O&G and new value chains for NCS OFS

NORWEGIAN COMPETENCE				COMMODITY INDUSTRY RELEVANCE					COMMENT
Norwegian geographical cluster	Field of industry competence	2019 Norwegian employment *[# employees]*	Examples of relevant players*	Oil and gas	Hydrogen ①	CCS ②	Offshore wind ③	Marine minerals ④	Competence relevance in potential alternate value chains
Eastern Norway	Seismic **TG2**	2,500	TGS emgs roxar allton PGS magseis fairfield	●●●	●●●	●●●	○○○	●●●	Very compatible with hydrogen, CCS and Marine minerals. CCS for the purpose of finding and monitoring the appropriate reservoirs and marine minerals to assess resource densities.
	Geology **TG2**			●●●	●●●	●●●	●○○	●●●	Relevant for initial and life cycle geological studies and analysis of formations.
	Engineering **TG4**	9,500	DR. TECHN. OLAV OLSEN mossmaritime GLOBAL MARITIME	●●●	●●●	●●○	●●○	●●○	All new energy markets are asset heavy, implying the need for engineering services. Pressure handling inherently makes O&G more complex than most the others.
	Subsea **TG4**	16,500	AkerSolutions TechnipFMC subsea 7	●●●	●●●	●●●	●●○	●●○	Most activity for new energy markets seen to happen in deeper-than-shelf waters. Analogues to risers, pipeline systems etc. likely to play a part.
West coast	Marine operations	9,000	DEEPOCEAN DOF Østensjø Rederi SOLSTAD OFFSHORE	●●●	●●●	●●○	●●●	●●●	Marine operations essential for CCS and marine minerals for bringing or disposing of commodity in question. Also relevant for offshore wind, especially in installation phase.
	EPC- and shipyards **TG4**	15,000	aibel VARD KVÆRNER KLEVEN ULSTEIN	●●●	●●●	●●○	●●○	●●●	Similar to the Engineering segment, relevance is attributed to asset heavy nature of the new energy markets and the need to design and manufacture components.
	Drilling **TG3**	10,000	Transocean ODFJELL DRILLING Seadrill	●●●	●●●	●●○	○○○	●○○	Drilling operations not relevant for wind. Limited relevance for marine minerals given far smaller exposure to pressure as a complexity in commodity extraction.
South coast	Drilling rig- and topside equipment **TG3**	22,000	Schlumberger ABB mhwirth NOV WÄRTSILÄ	●●●	●●●	●●○	●○○	●●○	Drilling equipment relevant for well dependent hydrogen and CCS value chains. innovative equipment is needed in the case of marine minerals for the purpose of extracting wet bulk.
Country wide	Automation and digital technologies **All**	26,000	Sekal Cognite Eelume KONGSBERG	●●●	●●●	●○○	●○○	●●●	Marine minerals set to be dependent on ROV-type solutions for subsea extraction of wet soil for processing.
	Other, incl. maintenance services **TG4**		DNV·GL AXESS I·K·M JOTUN	●●●	●●●	●●●	●●●	●●●	High maintenance and integrity requirements for all new energy markets. Safety especially relevant for hydrogen, leak detection for CCS, integrity of rotation equipment for wind and subsea IMR for marine minerals.

*Many of the listed oil field service companies perform work within several fields of competence, logos placed based on their main activities
Source: Rystad Energy research and analysis; Brønnøysundregistrene; Statistics Norway; Norwegian Petroleum

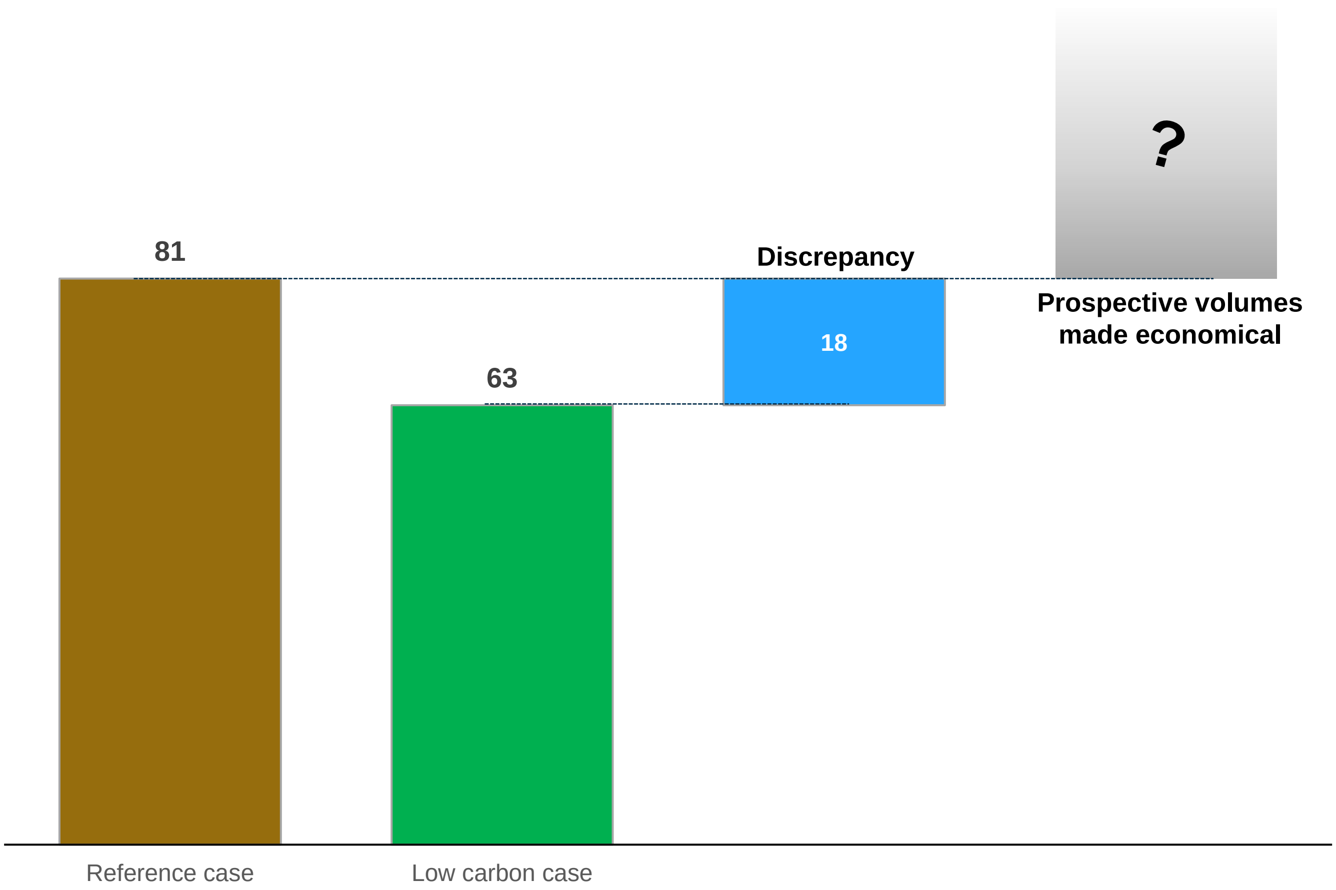
○○○ *Relevance degree - from high (3 filled) to low (1 filled)*

18 Bcf of gas separates produced gas between low carbon case and ref. case long term

1

Hydrogen

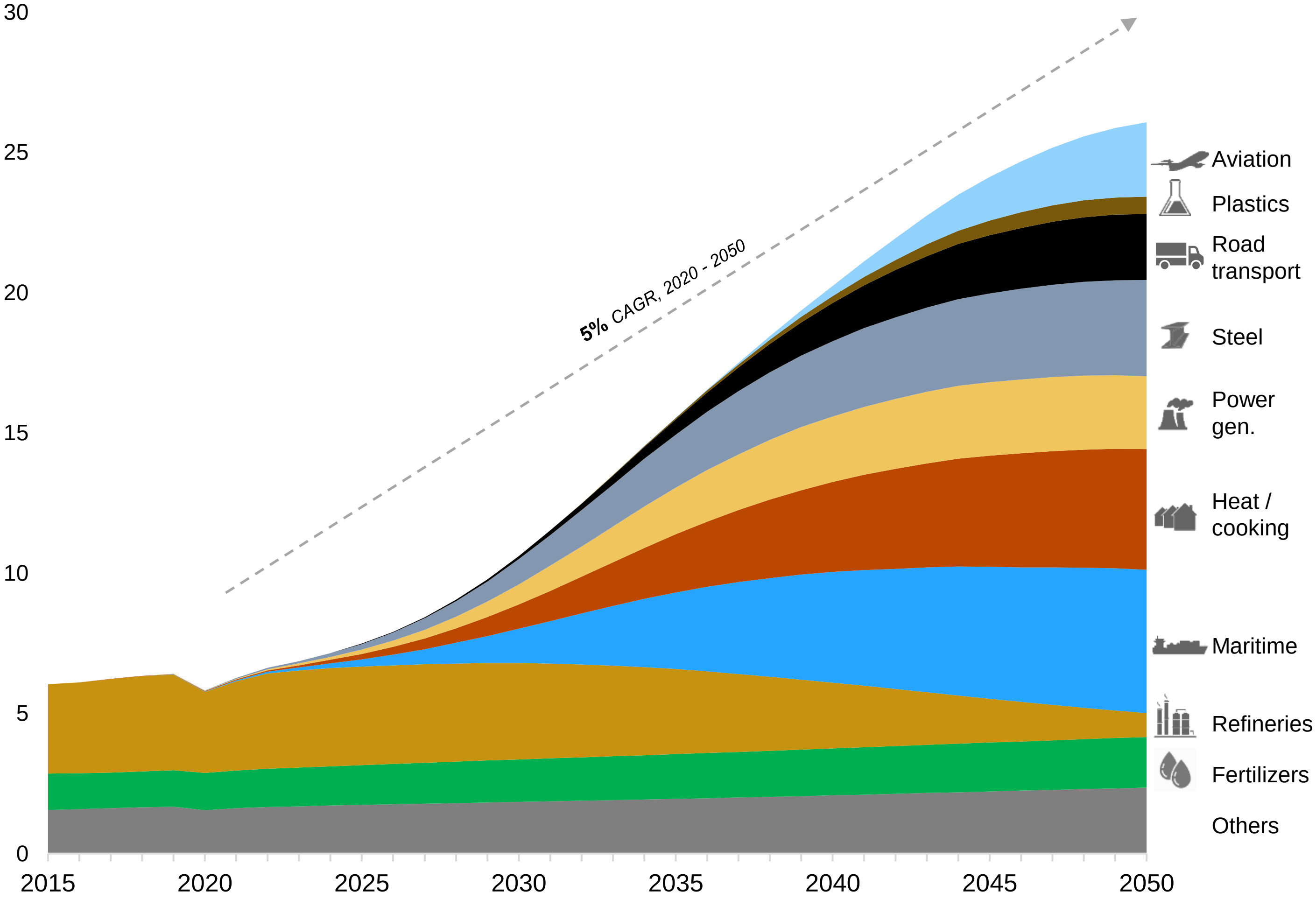
Long term total discrepancies in produced gas volumes for different scenarios (2030-2050)
Bcf



- The chart illustrates the discrepancy between long term produced gas volumes in a low carbon scenario vs the report's reference scenario.
- The low case represents a 22% reduction from the reference case, illustrating a relative robustness of NCS gas production long term.
- Blue hydrogen can play a part in making these 18 Bcf viable for production also in a low carbon case, making up for "lost" volumes. The reasoning applies both from an emissions point of view and a cost point of view.
    - From the cost perspective, these gas volumes may become economical as long as blue hydrogen is a cheaper alternative to green hydrogen.
    - From a "cost-of-emissions"-perspective, producing the gas becomes viable if displacing oil or coal.
- In addition, one might speculate whether the prospect of blue hydrogen production makes additional volumes viable for extraction on the NCS

Hydrogen demand expected at 5% annual growth in Western Europe towards 2050

Western European hydrogen demand by consumer segment
Mtpa

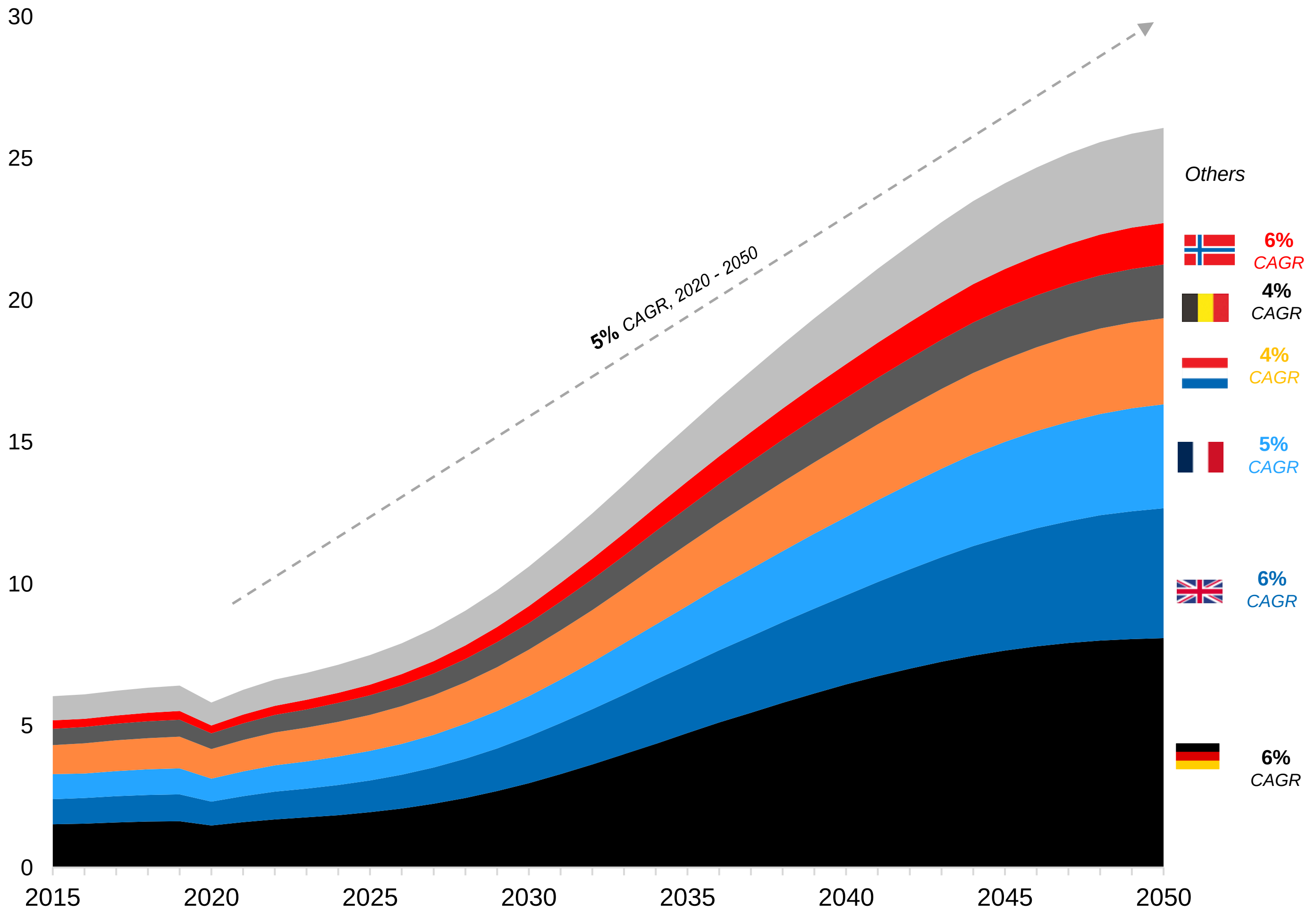


- Rystad Energy estimates Western European hydrogen demand to increase by an average of 5% annually towards 2050.
- The most prominent segments include maritime applications, road transport and aviation, where the prospect of hydrogen displaces oil as the main energy bearer.
- One should still consider that classing societies still recommend ship owners to use LNG as a fuel in order to achieve IMO compliance. This, along with a later onset of hydrogen for aviation and road transport makes the prospects of hydrogen for the transportation sector limited before the 2030s.
- Other large segments include those where hydrogen displaces gas: heat and cooking, power generation and furnaces for steel production.

*Assets omitted in any of the cases not applied
Source: Rystad Energy research and analysis; UCube

Norwegian gas end-markets Germany and UK set to be largest consumers

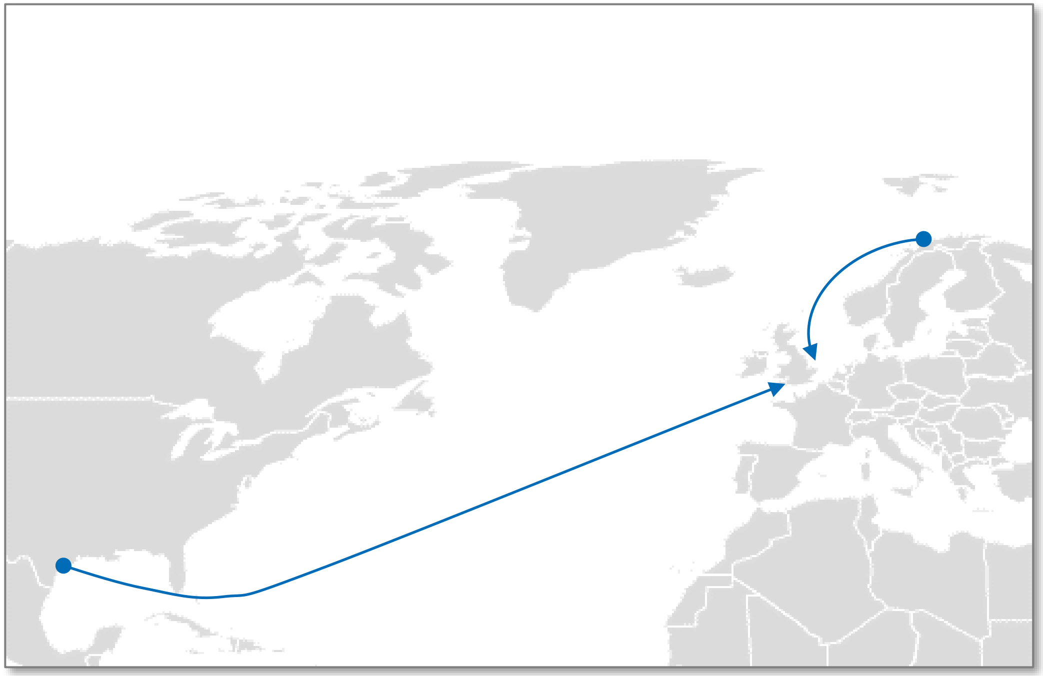
Western European hydrogen demand by country
Mtpa



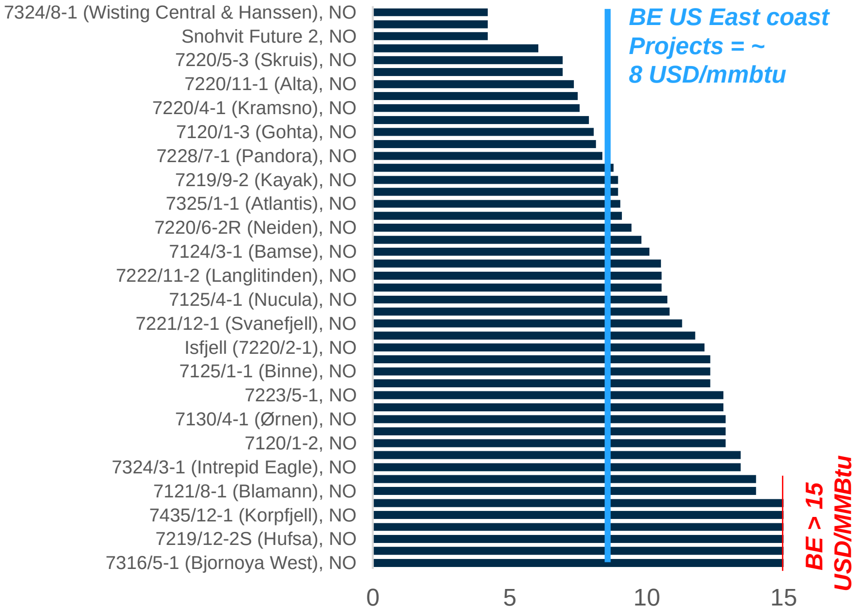
- Breaking Western European demand down into demand per country, Germany and the UK emerge as the markets with the highest grown, both outpacing the general annual growth rate of 5%.
- Countries like Belgium and the Netherlands are seen to experience more modest growth, yet still become sizable demand sinks by 2050.
- Common for the four countries mentioned above is that they are all receivers of Norwegian piped gas today. Consequently, receiving gas from Norway and converting it to hydrogen locally is a viable option to meet hydrogen demand.
- Norway also exerts “healthy” growth at 6%, with most of this being related to the maritime sector.

*Assets omitted in any of the cases not applied
Source: Rystad Energy research and analysis; UCube

Producing hydrogen based on Barents gas faces same challenges as Barents LNG



Breakeven gas price of NCS Barents Sea discoveries*
USD/mmbtu

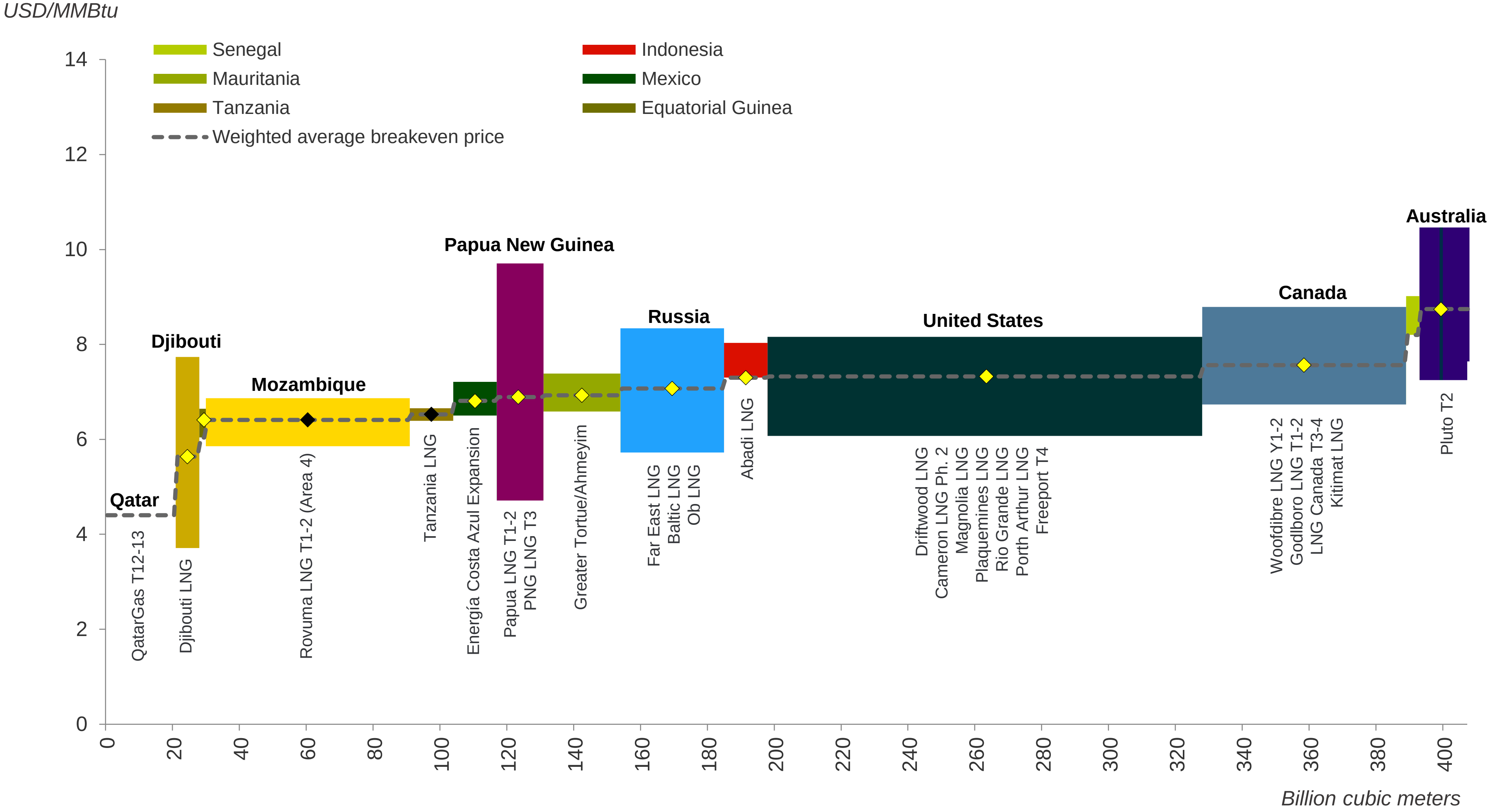


- Converting Barents gas to LNG for sale in the European (or any other) market implies that it will have to compete on cost with Henry Hub LNG from the US.
- US east coast gas is currently in excess and is likely stay that way as long as shale oil production continues to increase. The excess gas is mostly associated from oil production, and sets a «roof» for the European gas price which Barents LNG will not necessarily be able to beat.
- In addition, the prospective Barents gas has mostly not been matured yet, while the Henry Hub gas comes from fields in production.
- Transporting the LNG beyond Europe to Asian markets implies adding a costly transportation element to each unit sold, which is set to be higher than incurred by Qatari or Australian exporters.
- This set of issues affecting prospective Barents LNG production is likely analogue to the prospect of blue hydrogen production in the region.
- These market driven hurdles are in addition to societal and social hurdles associated with drilling in the Arctic.

*Includes liquefaction and transportation to Asia
Source: Rystad Energy research and analysis

The US, with its chunk of future LNG resources, is likely to be the price setter

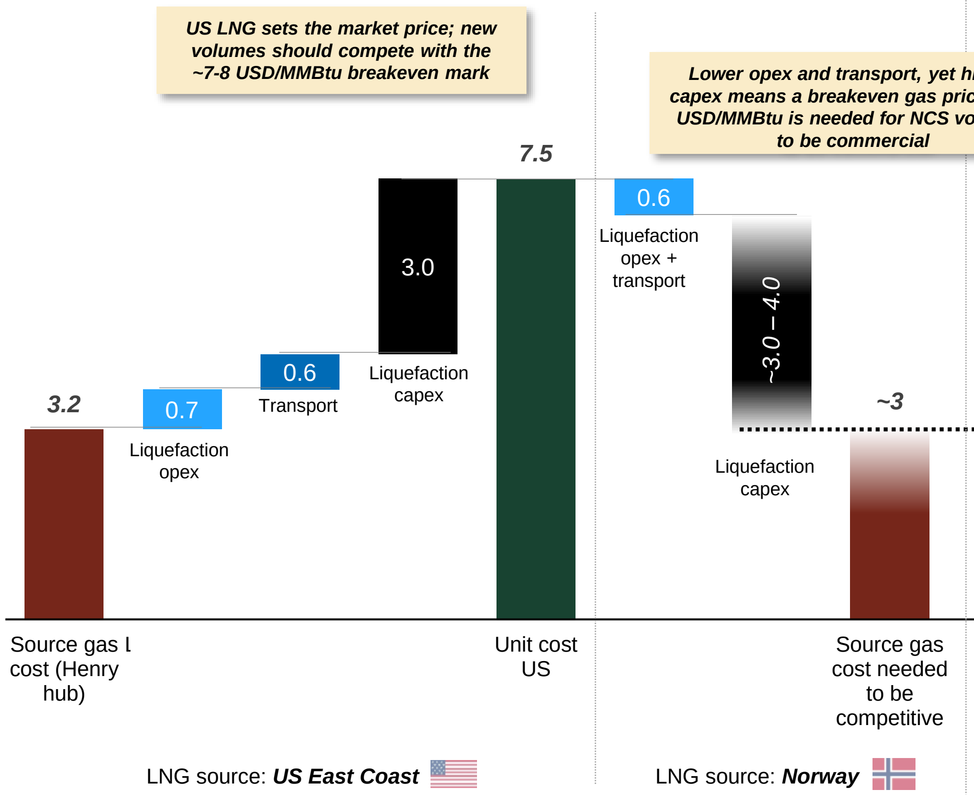
Volumes and breakeven prices* for unsanctioned LNG projects, 2040



*Includes transport cost to Asia
Source: Rystad Energy research and analysis; Rystad Energy GasMarketCube

Prolific NCS gas fields out of the money if made to compete with US LNG

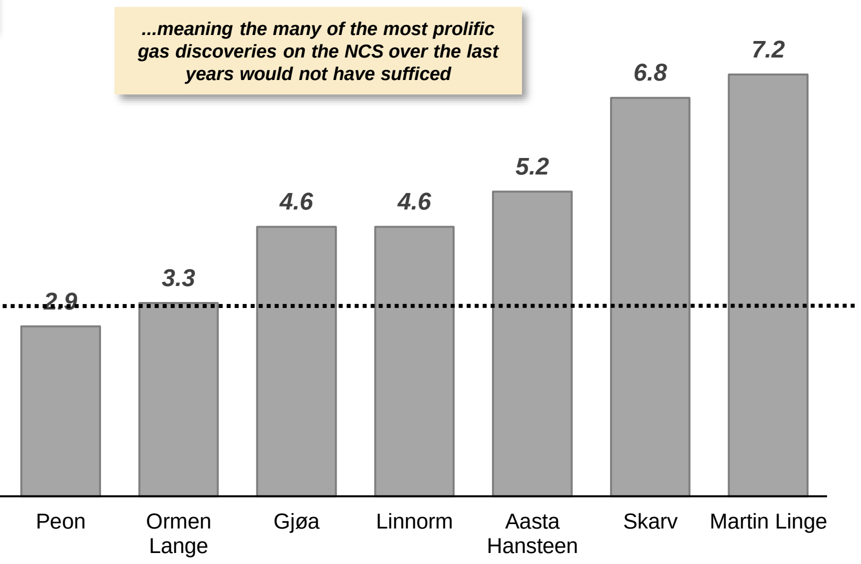
LNG cost of supply for delivery to continental Europe
USD/MMBtu



US LNG sets the market price; new volumes should compete with the ~7-8 USD/MMBtu breakeven mark

Lower opex and transport, yet higher capex means a breakeven gas price of ~3 USD/MMBtu is needed for NCS volumes to be commercial

Breakeven gas price of selected NCS stanalone gas fields
USD/MMBtu



...meaning the many of the most prolific gas discoveries on the NCS over the last years would not have sufficed

- Selling gas as LNG ultimately means competing with cheap gas drawn from Henry Hub and liquefied on the US east coast.
- While liquefaction opex and transport from Norway to the European continent (using Snøhvit figures) is likely to be cheaper than from the US east coast, liquefaction capex will likely be higher. As an example, Snøhvit capex per liquefaction capacity was more than 75% higher than any project in the US. Capex for an LNG plant developed now is likely to be lower, albeit still higher than for US projects.
- Norwegian gas projects will need a breakeven gas price of about 3 USD/MMBtu to compete with US LNG in Europe. Out of the most prolific, gas heavy discoveries made on the NCS the last 5 years, few can boast these economics.
- The example is likely extendible to LNG exported to the Asian market; the relative advantage of distance from Norway to market shrinks.

Source: Rystad Energy research and analysis; GasMarketsCube; UCube

Two sources of demand for Norwegian gas for hydrogen are seen as most likely

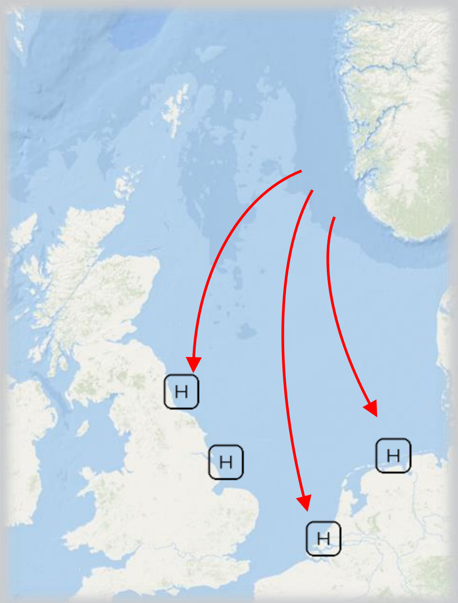
In light of hydrogen transportation carrying considerable cost and safety concerns, 2 possible applications of Norwegian gas for blue hydrogen are seen as most viable.

1. Gas export for hydrogen conversion in end-market

Given that feedstock is a sizable share of blue hydrogen costs are related to feedstock, competitive Norwegian gas emerges as one of the most viable alternatives for blue hydrogen produced in continental Western Europe.

This creates demand for Norwegian gas as long as local green hydrogen production is not deemed cheaper, something which is bound to happen at some point as carbon taxes and gas prices increase, and the price of renewable power decreases.

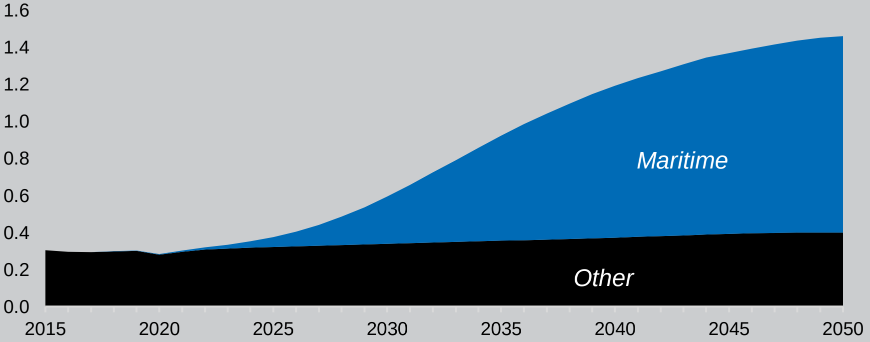
Still, Norwegian interests can still influence blue hydrogen production in for instance the UK. One analogue is Gassco's interest in receiving terminals for gas in the UK.



2. Norwegian hydrogen production for the maritime segment

Hydrogen for maritime applications in Norway represents the majority of domestic demand from about 2035 beyond. The Topeka vessel will be one of the first such applications, set to traverse between Norwegian supply bases by the mid-2020s. A large share of hydrogen demand before this point is associated with Yara's fertilizer production. The company has communicated ambitions to meet this hydrogen demand through

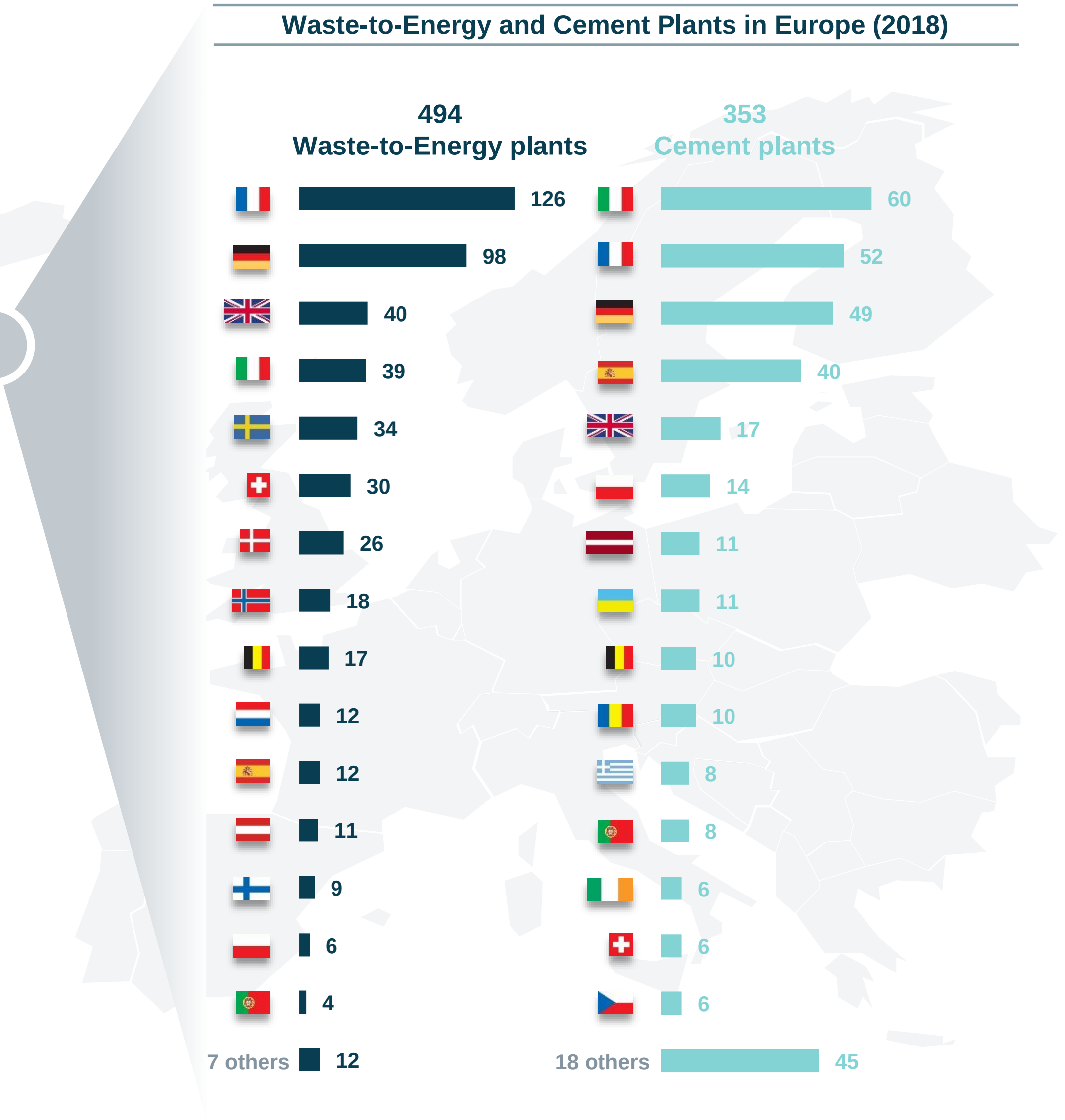
Norwegian hydrogen demand by consumer segment
Mtpa



Despite decarbonization measures, the potential for capture in industry remains

Industrial segment	Electrification mitigates most emissions	H2 mitigates most emissions
Production of ferroalloys	✗	✗
Production of silicon	✗	✗
Production of cement	✗	✗
Waste treatment	✗	✗
Production of calcite and gypsum	✓	✗
Production of aluminum	✗	✓
Natural gas processing	✗	✓
Refineries	✗	✓
Production of fertilizer	✗	✓
Petrochemical industry	✗	✓
Metal production	✗	✓
Methanol production	✗	✓

Waste-to-Energy and Cement Plants in Europe (2018)



Source: Rystad Energy research and analysis, CEWEP, CEMNET

The choice of offshore or onshore storage is to a large extent geographically conditioned

Offshore	Characteristics	Onshore
As offshore storage is not directly visible to the public, and a long distance from any population, the public sentiment has been more positive towards offshore than onshore carbon storing. ✓	**Public sentiment**	✗ The public is reluctant to experimenting with storage right beneath where many people live, people do not want this in their own "backyard".
Offshore areas are typically owned by the government. ✓	**Reservoir ownership**	✗ Dispute on who has ownership of the reservoir can arise. It could be the landowner that owns the land above the reservoir, regional authorities or the government.
Compared to onshore storage, there are fewer interests involved in the process, potentially leading to easier permissions. ✓	**Legislation**	✗ The legislation of onshore storage could prove difficult due to a variety of interests like disturbance of drinking water, vicinity to populations and land ownership.
Industry, which are typical subjects to CCS, are typically situated around ports. This makes the transport to offshore storage convenient. ✓	**Carbon proximity**	✗ Locating storage sites in proximity to where the emissions are created could be challenging. Transporting the carbon long distances could also be difficult.
Pipelines, wellbores, rigs and vessels from the offshore oil and gas market can be reused with small adjustments. The carbon can also be carried in ships, making the transport flexible. ✓	**Infrastructure**	✗ Few existing feasible solutions for long-distance pipeline transportation of CO2 onshore; lacks the flexibility of shipping
Many players with experience with offshore reservoirs from segments like offshore oil and gas. ✓	**Existing competence**	✓ Many players with experience with onshore reservoirs from onshore oil and gas.
Large storage capacity offshore. ✓	**Capacity availability**	✓ Large storage capacity onshore.
Offshore operations are in general more expensive than the comparable situation onshore. However, using existing infrastructure would lower the costs. ✗	**Cost**	✓ Operations onshore are in general cheaper than onshore. However, without existing infrastructure onshore storage could become costly
During seismic examination of the reservoir, animal life sensitive to sound could be affected. ✗	**Animal life**	✓ No prominent effect on animal life.

Particularly relevant in Europe

Offshore storage has a strong momentum in European regions and will probably be the most used storage method in near-future in these areas. This is due to simpler legislation and existing knowledge and infrastructure.

Relevant for specific regions

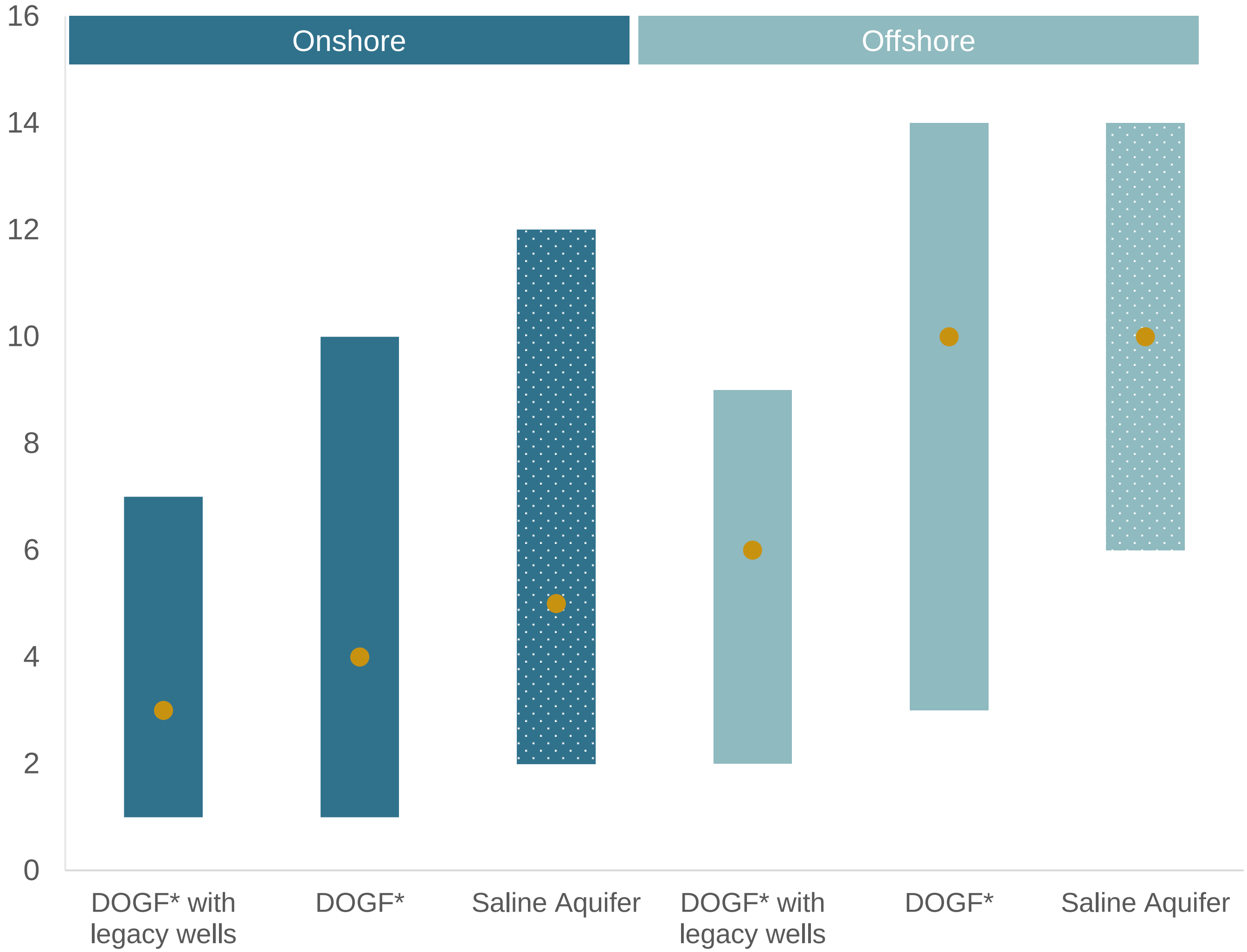
Onshore storage faces skepticism in the public, making legislation and financing more difficult. This further leads to placement of storage sites far away from industry and people, which is not suitable in some regions.

Source: Rystad Energy research and analysis

Offshore CO2 storage and late-life deposits

CO2 storage costs vary with field type, location and region

CO2 storage cost estimates from the Global CCS Institute (2011)
EUR/ton CO2 stored

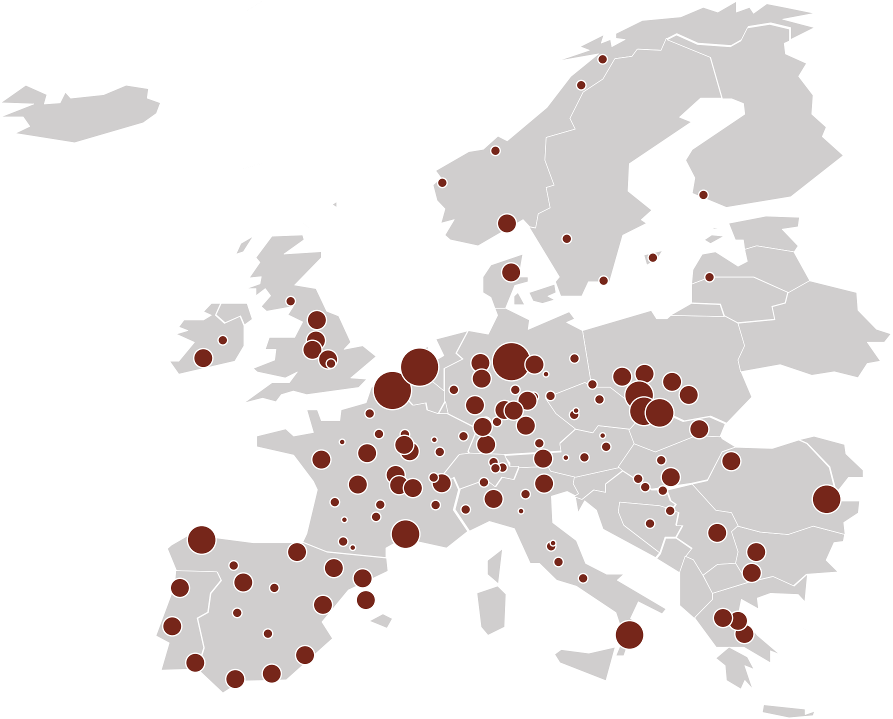


*Depleted oil and gas field
Source: Global CCS Institute

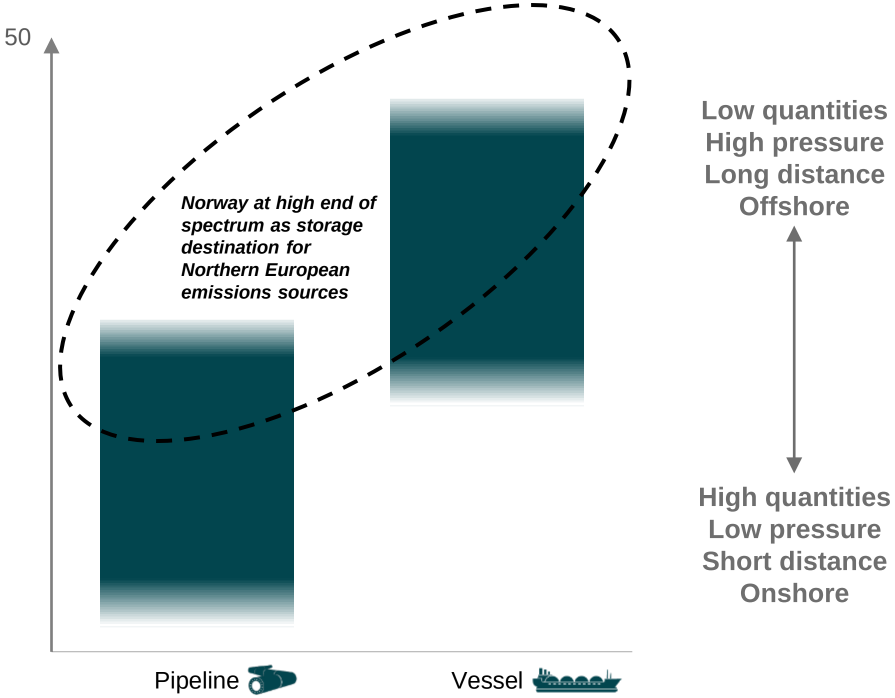
- The chart to the left show estimates of storage cost per ton CO2 from the Global CCS Institute. The estimates are from 2011, but the report states that the estimates are calculated based on expectations for the cost when CCS reaches commerciality, expected in the 2020s.
- Depleted oil and gas fields (DOGF) will in general be cheaper than saline aquifers.
- Onshore storage will in general be cheaper than offshore, but there are exceptions to this.
- The average storage costs onshore based on these estimates is 4 EUR/ton CO2, while offshore storage usually costs the double.
- The estimated numbers come from a somewhat old source, but Global CCS Institute has indicated numbers within this range in their latest 2020 report as well.

Main carbon emission points located in Continental Europe – storage in Norway requires long distance transport of captured carbon

Heavy emitting point sources with CCS relevance*



Transport costs of captured carbon
USD/tonne



Norway located far away from Europe's most emitting point sources and the largest industrial clusters.

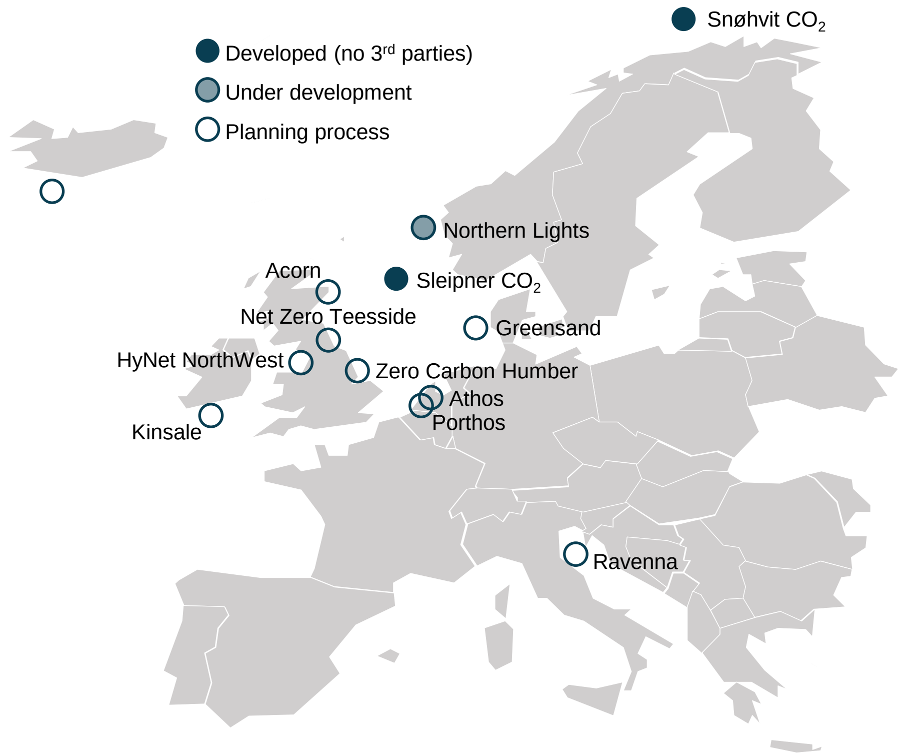
Stand-alone point sources with transportation by ship as the most feasible solution, especially short term as ships adapt more easily to shifting demand.

As Norway is located far away from the largest point sources, the country is among the more costly to transport CO_2 to in Europe. For pipeline transportation, the cost is driven by the large development capex needed, as long-distance offshore pipelines are expensive. For vessel transportation the cost is driven by longer distances implying higher unit costs related to e.g. fuel consumption and personnel.

*Illustrative
Source: Rystad Energy research and analysis; Norwegian Government; E-PRTR

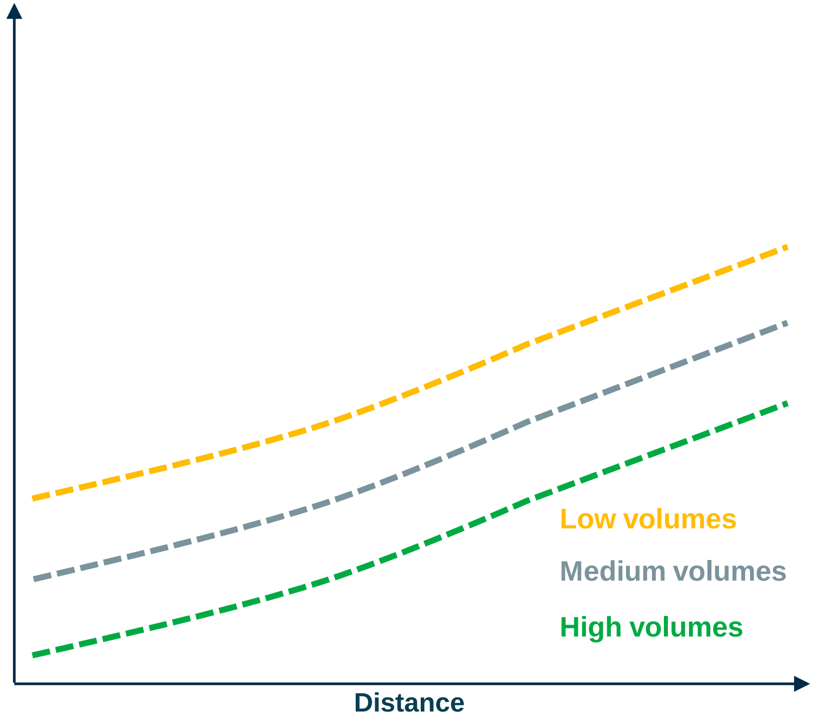
Still, early mover advantage and future pipeline development may make Norway a preferred large scale carbon storage destination

Known full scale CCS projects



Transportation cost of captured carbon by pipeline

Cost per unit of CO_2 at different distances of total transportation



Norway is an early mover, being the first European country expected to launch a full-scale CCS project receiving CO_2 from third parties.

Northern Lights is the only offshore storage project where FID is already taken – this could provide Norway with a lasting early mover benefit e.g. due to economies of scale.

The Northern Lights team has ambitious growth plans, picturing Northern Lights as a European CCS hub. Several potential clients have already signed MoUs.

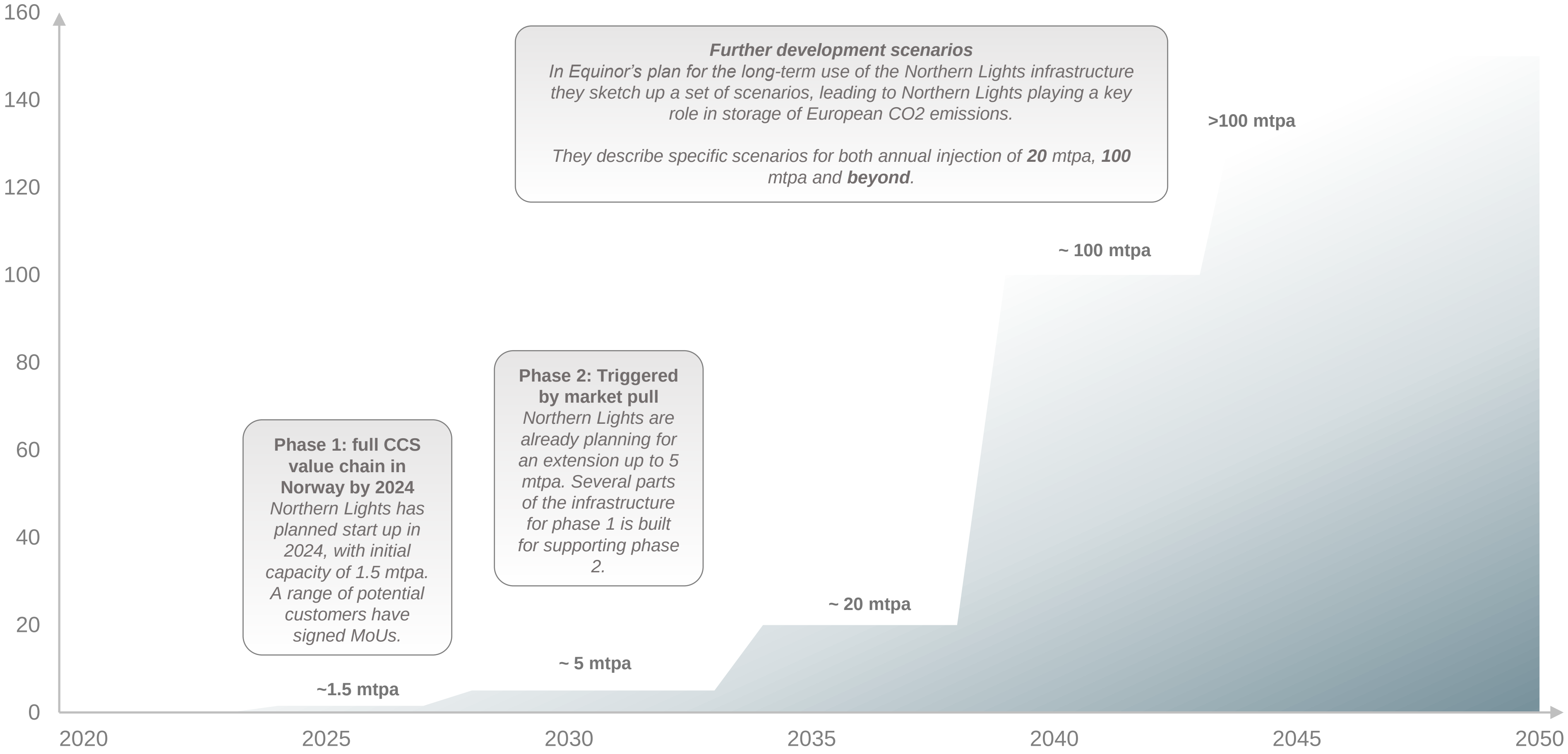
The chart shows how transportation costs for a unit of CO_2 by pipeline are highly dependent on both distance and quantum transported.

Northern Lights is engaging in active market development, aiming to secure large quantities of CO_2 for future development projects in order to pull down unit cost, making Norway more competitive.

Source: Rystad Energy research and analysis; Paper: "Ship transport – A low cost and low risk CO_2 transport option in the Nordic countries"

Equinor with ambitious plan for Northern Lights playing a key role in European CCS

Equinor long term plan for stored volumes at Northern Lights*
Million tonnes CO2 per year



Further development scenarios
In Equinor's plan for the long-term use of the Northern Lights infrastructure they sketch up a set of scenarios, leading to Northern Lights playing a key role in storage of European CO2 emissions.

*They describe specific scenarios for both annual injection of **20** mtpa, **100** mtpa and **beyond**.*

Phase 1: full CCS value chain in Norway by 2024
Northern Lights has planned start up in 2024, with initial capacity of 1.5 mtpa. A range of potential customers have signed MoUs.

Phase 2: Triggered by market pull
Northern Lights are already planning for an extension up to 5 mtpa. Several parts of the infrastructure for phase 1 is built for supporting phase 2.

*Timing and volumes are uncertain. Illustrative, based on scenarios sketched out in Equinor's plan for long term use. Source: Rystad Energy research and analysis

10 reasons to develop floating offshore wind in Norway

Realize offshore wind resources

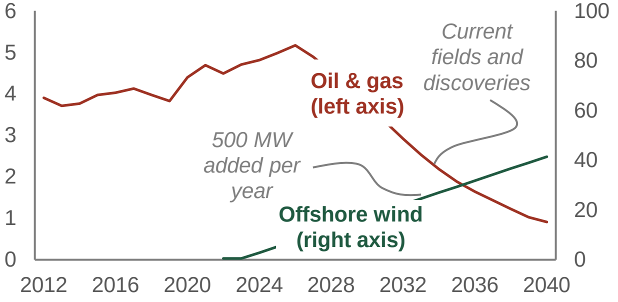
1 **Offshore wind is highly competitive**
Offshore wind power is a highly competitive energy source compared to other energy sources; cost trajectories of floating and bottom-fixed wind are expected to converge during the 2020s.

2 **Excellent offshore wind resources**
Norway has excellent wind resources offshore, better than onshore and most other offshore regions. However, floating solutions are required, as water depths mostly exceed 60 meters.

3 **Electrification requires more green power**
Domestic demand for more green power to realize stated climate ambitions. Replacing fossil fuels in Norway implies 30-50 TWh in additional domestic demand annually.

4 **Maintain position as energy exporter**
Offshore wind could enable substantial energy exports from Norway, also after the age of oil and gas. Export method is flexible, either as electrons, green molecules or energy intensive products.

Offshore energy production
Oil and gas (kboe/d) Offshore wind (TWh)



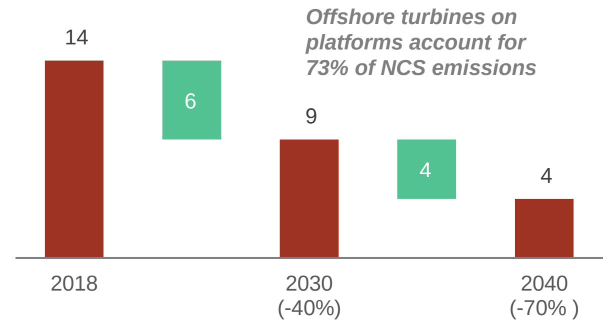
Reduce CO_2 emissions

5 **Norway nears zero emissions in 2050**
National emission targets for CO_2 are now echoed by the oil and gas industry, with a 40+% reduction by 2030 and near zero by 2050. Oil and gas extraction accounted for 14 Mt CO_2eq in 2018

6 **Offshore wind to cut offshore emissions**
Offshore oil and gas facilities represent large emission point sources located in areas with excellent wind conditions. Offshore wind could thus reduce the need for new onshore power generation associated with large-scale offshore electrification, with limited effect on power prices onshore.

7 **Norway can be a global catalyst**
Norway can be a global catalyst for commercialization of floating offshore wind, as other countries have been for solar PV and bottom-fixed offshore wind. Accelerated adoption of floating offshore wind globally could yield CO_2 cuts beyond the reduction from single projects.

NCS oil and gas emissions targets
Million tonnes CO_2 eq.



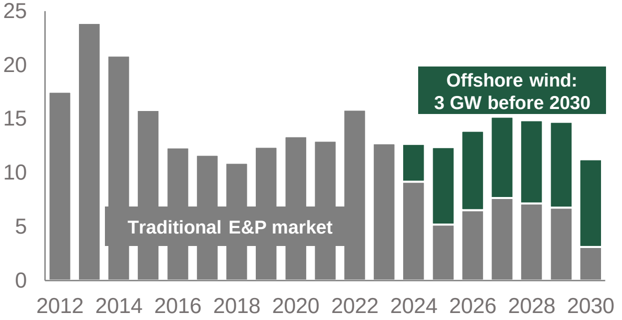
Develop new jobs and industry

8 **Good match for Norwegian suppliers**
Norwegian suppliers are very well positioned to reap the benefits of industrialization of floating offshore wind. This is already illustrated through awarded contracts on existing small-scale floating wind projects.

9 **Oil and gas industry needs to diversify**
Domestic construction workload for E&P infrastructure (excl. subsea) set to decline rapidly in the mid-2020s. Offshore floating wind represents a new adjacent growth opportunity, to further develop existing capabilities into new applications.

10 **Large export potential if successful**
Global market potential for floating wind is estimated at ~2500 billion NOK (2025-2050), of which the Norwegian supplier industry typically could compete for 3-20%. A considerable home market will improve the odds of establishing a new export industry in Norway, as export revenues from oil and gas decline.

Norwegian market for offshore infrastructure fabrication
Billion NOK nominal

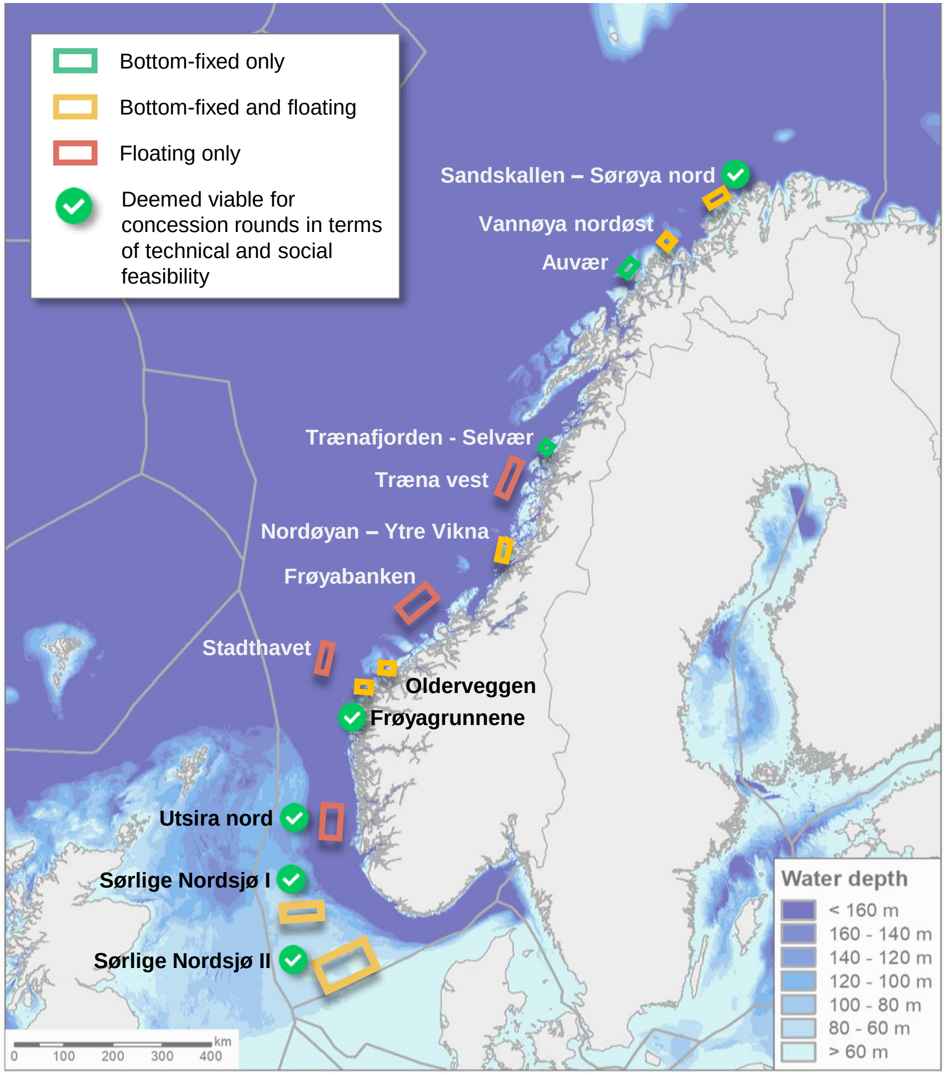


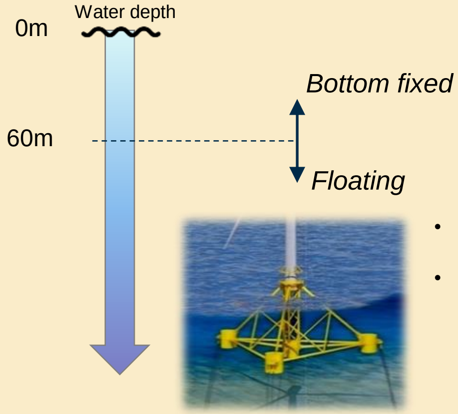
Source: UCube; Statnett – Et elektrisk Norge (April 2019); Menon (Sept 2019); Norsk olje og gass (Jan 2020); Rystad Energy research and analysis

Deep Norwegian waters makes development of low-cost floating windmills crucial for large scale deployment

NCS water depth map

Geographical location of areas recommended for offshore wind activity





- Today, bottom-fixed offshore wind cannot be installed at depths greater than ~60 m.
- Sea depth and complicated seabed conditions make the cost of building bottom-fixed offshore wind in Norway greater than the average cost in Europe today. Depth contributes the most to the increased cost.

- NVE, The Norwegian Water Resources and Energy Directorate, is a Norwegian government agency responsible for the country's water resources and energy supply.

- In 2013, NVE identified five areas being technically and economically suitable for offshore wind with relatively few conflicts of interest. The areas could also be easily connected to power networks without major challenges by 2025.

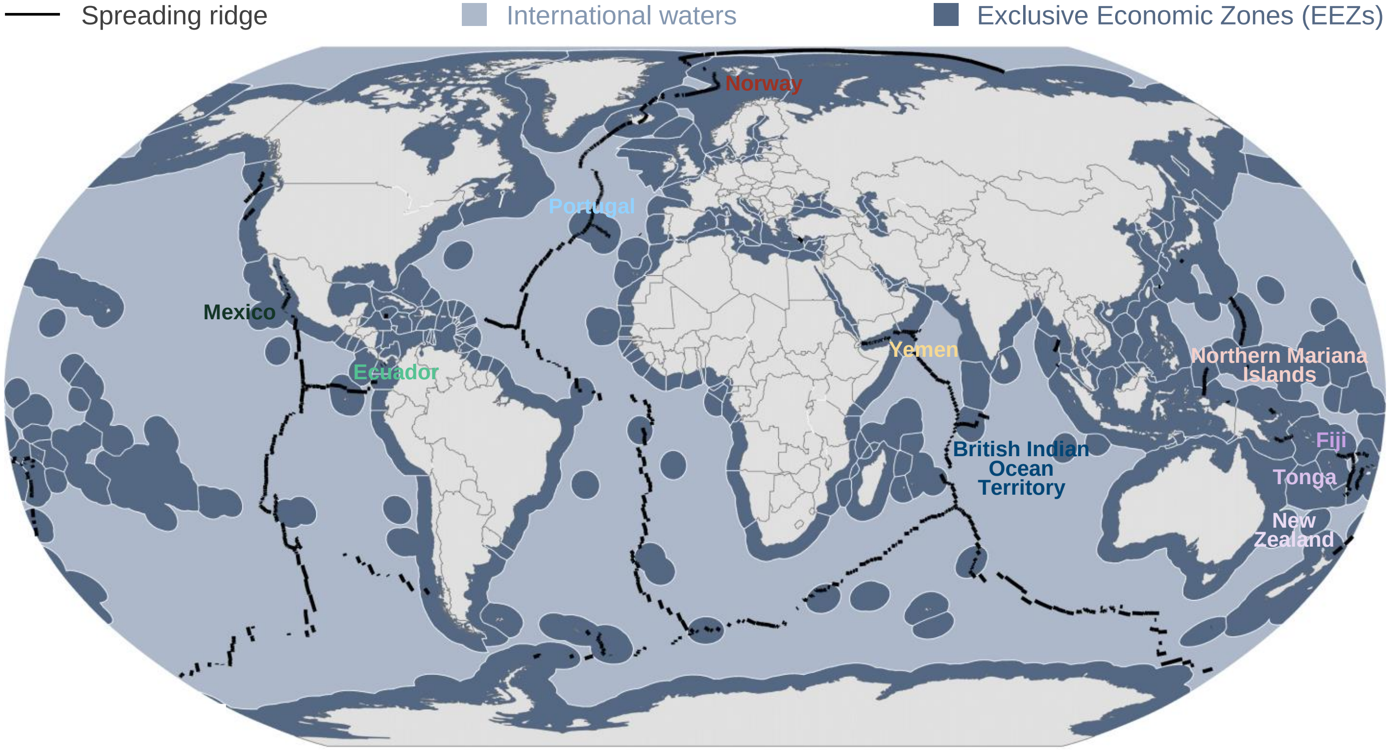
- The remaining areas have challenges related to either technical aspects and/or area interests. However, the challenges may be solved by future technology development and/or mitigating measures.

2018: *NVE recommends to open Utsira nord and Sørlige Nordsjø I or II for renewable energy production at sea.*
2020: *The government opens Utsira nord* and *Sørlige Nordsjø II for offshore wind production.*
2021: *From 1 January 2021 companies can apply to obtain a license for development and construction of offshore wind power projects at Utsira Nord and Sørlige Nordsjø II.*

Source: Rystad Energy research and analysis; NVE

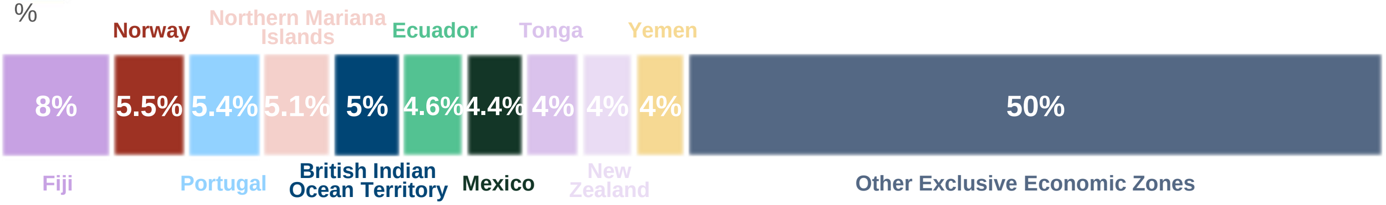
Only Fiji beats Norway on economic rights to spreading ridges – large export potential

Global active spreading ridge formations by ownership



Global spreading ridge in EEZs by 2020 national ownership

%



Source: Rystad Energy research and analysis

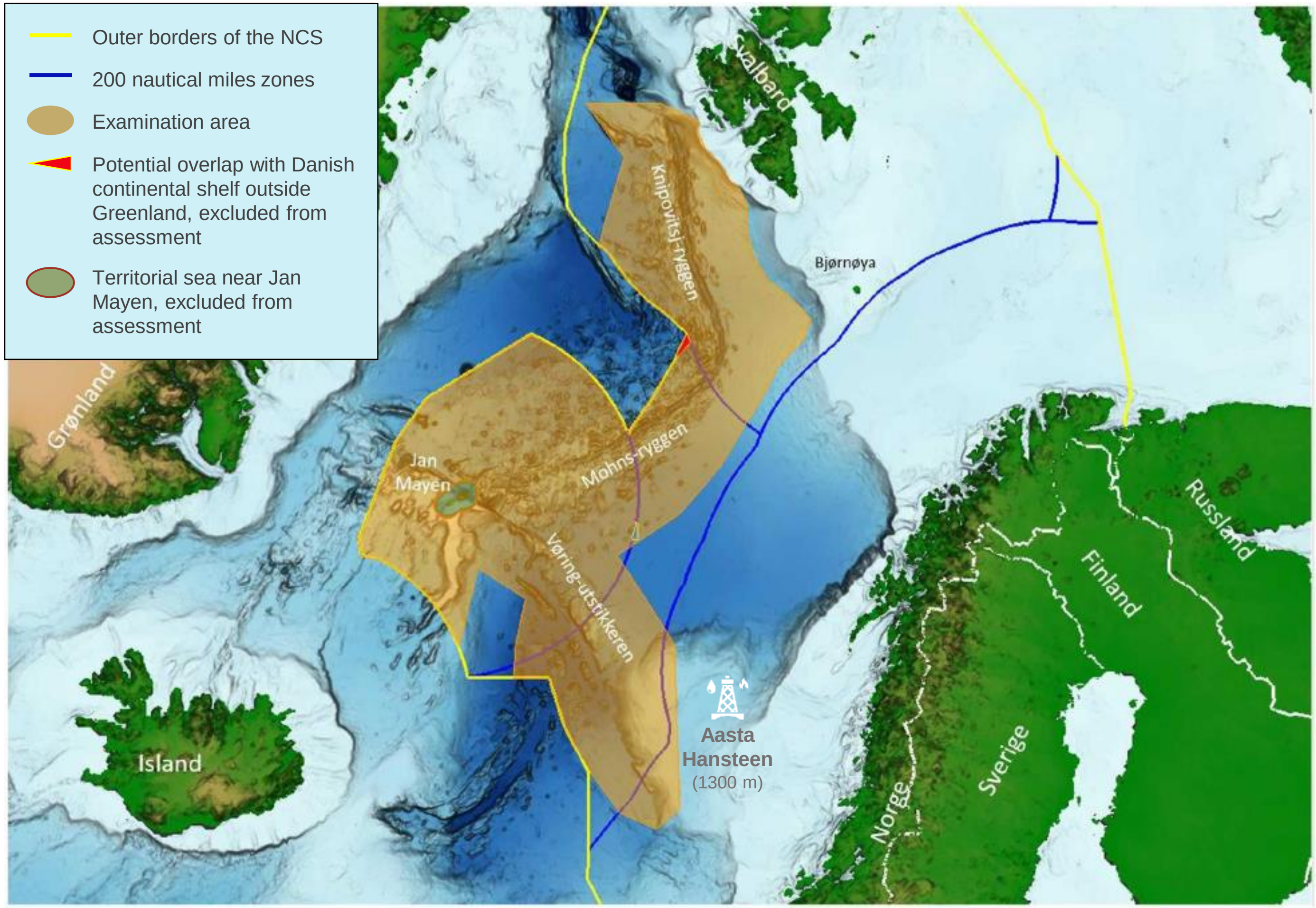
The map to the left indicates global active spreading ridges by national and international ownership, while the lower bar displays ownership of the ridges in exclusive economic zones by top ten countries and remaining.

Norway holds as much as 5.5% of the world's active spreading ridges, with only Fiji having resource rights to more (8%). However, only Mexico and the UK (represented by the British Indian Ocean Territory) compare to Norway in terms of having a well-established oil and gas industry. The latter is a strong Norwegian competitive advantage as we hold eminent oil and gas competence and technology (from exploration to operations) which overlap well with potential marine minerals extraction.

Norway is further one of few countries with a marine mineral legislation already in place (est. in 2019), and our resource and impact studies being led by authorities shows signs of political willingness and stability. With few comparable players among top ten, a first-mover Norwegian marine minerals industry (including developed technology) have great export potential.

Ultra deepwater Norwegian spreading ridge located between Jan Mayen and Svalbard

The Norwegian spreading ridge



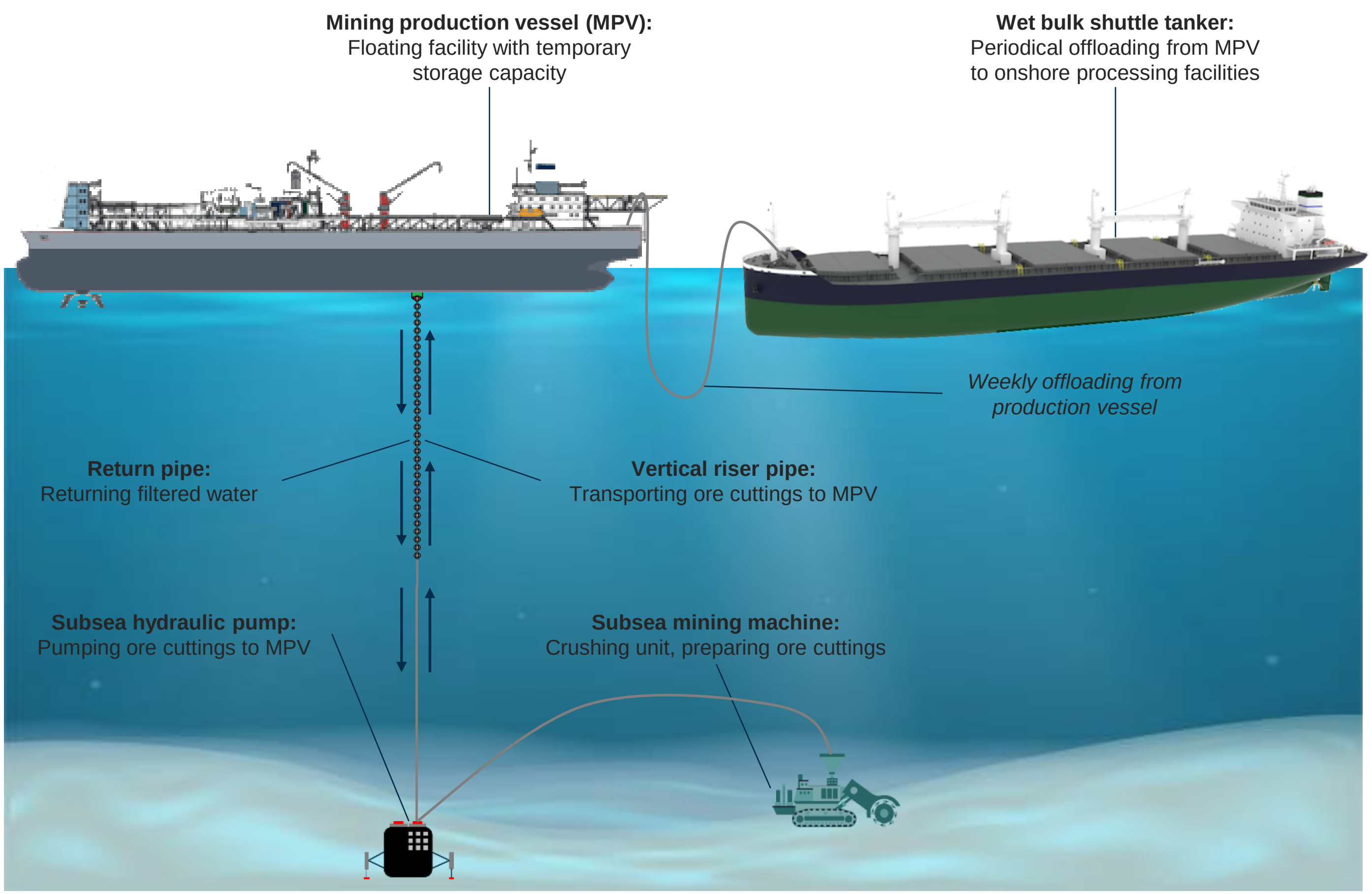
The Norwegian territorial spreading ridge (ca. 1300 km long) is located between Svalbard and Jan Mayen, with the Knipovich Ridge up north and the Mohns Ridge further south. NPD's resource mapping studies over the 2018 to 2020 period have been made along the Mohns Ridge.

The approximate distance from the Norwegian mainland (from Tromsø) to the mid of the Norwegian spreading ridge is 700 km (~380 nautical miles). Located at such distances away from the Norwegian coastline (mainland), the waters reach depths in the range of 2000 to 3000 meters. While the most southern parts of the Mohns Ridge and furthest north on the Knipovich Ridge have some water depths in the 1000 to 2000 meters range, most of the Norwegian spreading ridge is located thousand meters deeper. In comparison the water depth at Aasta Hansteen in the Norwegian Sea, the NCS' currently deepest operated oil and gas field, is 1300 meters.

Source: Rystad Energy research and analysis; Norwegian Petroleum Directorate (NPD)

Numerous opportunities for application of oil and gas technology

Illustration of potential concept for offshore marine minerals extraction*



Mining production vessel (MPV):
Floating facility with temporary storage capacity

Wet bulk shuttle tanker:
Periodical offloading from MPV to onshore processing facilities

Weekly offloading from production vessel

Return pipe:
Returning filtered water

Vertical riser pipe:
Transporting ore cuttings to MPV

Subsea hydraulic pump:
Pumping ore cuttings to MPV

Subsea mining machine:
Crushing unit, preparing ore cuttings

Technical concept explained:

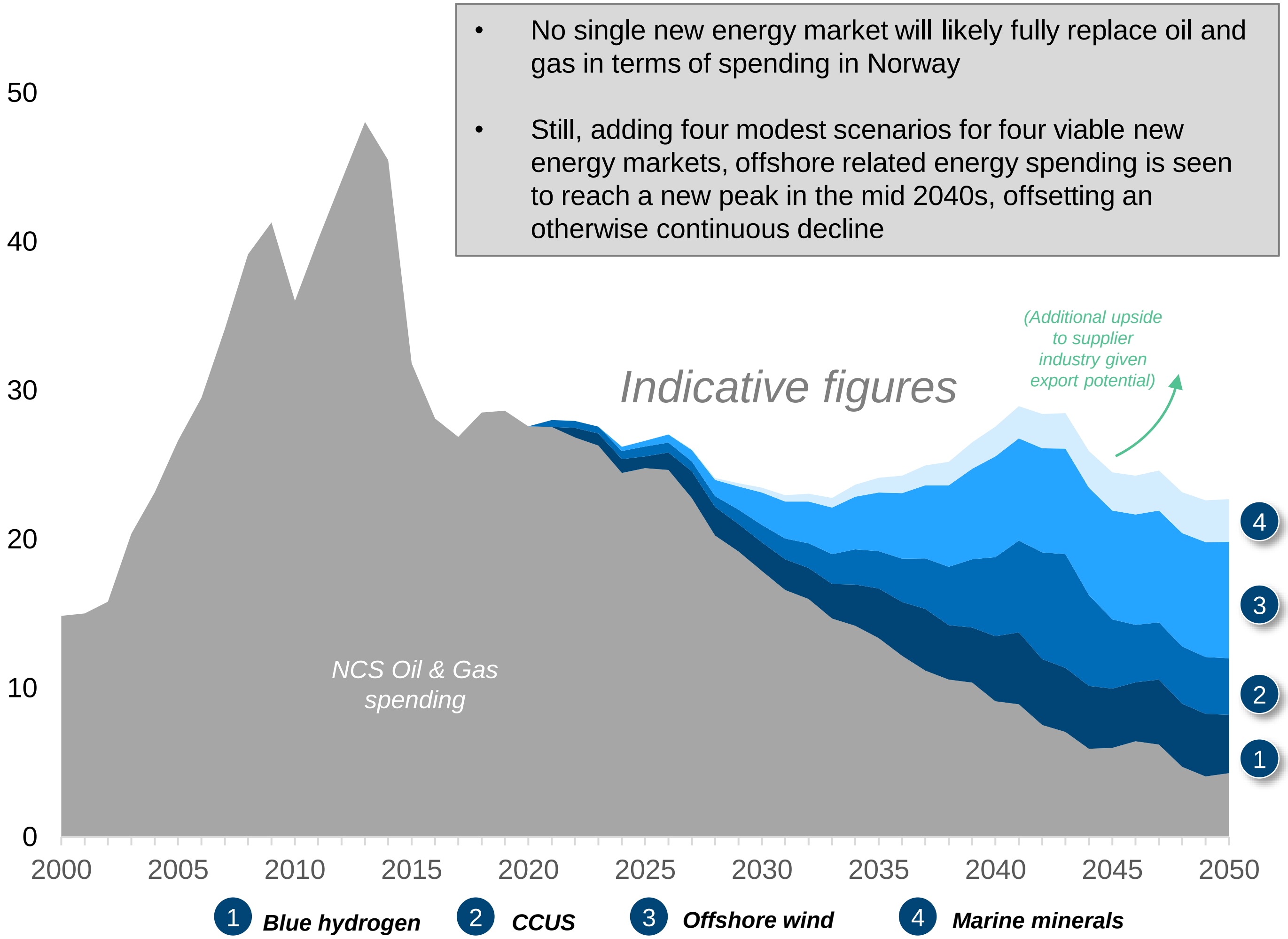
- **Subsea mining machine** crushes mineral rich rocks from inactive massive sulfides on the sea floor, providing ore cuttings
- **Subsea hydraulic pump** unit lifting the ore cuttings to the mining production vessel (MPV)
- **Vertical riser pipeline** system transports the ore cuttings from mining operations to the MPV for temporary storage
- **Water filtering system** on the MPV sorts minerals from the water
- **Return pipeline** pumps clean water back down to the subsea hydraulic pump unit in a closed loop system
- **Wet bulk shuttle tanker** arrives periodically to transport the temporarily stored wet bulk mineral mix from the MPV to an onshore processing facility

The concept is focusing on the offshore extraction process and does currently not account for any onshore facilities.

*Illustration not to be considered as technical drawing
Source: Rystad Energy research and analysis

New value chains may compensate for a decreasing spend in oil and gas

Norwegian oil and gas spending from sanctioned fields* and parallel competence segments
USD billion



- No single new energy market will likely fully replace oil and gas in terms of spending in Norway
- Still, adding four modest scenarios for four viable new energy markets, offshore related energy spending is seen to reach a new peak in the mid 2040s, offsetting an otherwise continuous decline

Indicative figures

(Additional upside to supplier industry given export potential)

*Includes both capital and operational expenditures, in addition to historical exploration costs and assumed future exploration costs
Source: Rystad Energy research and analysis; Rystad Energy UCube

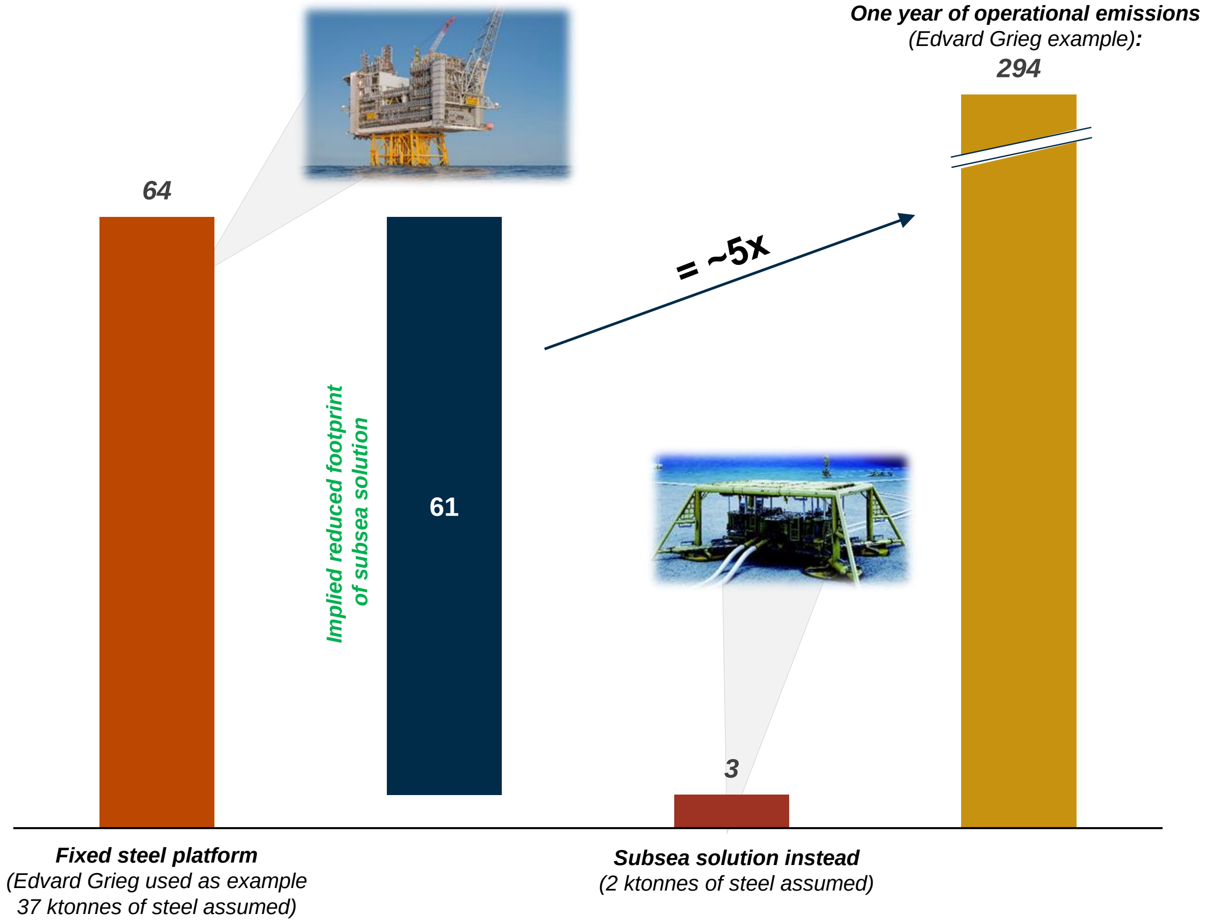
Order of magnitude calculations:

- **Hydrogen:** Assumed to be able to cover volume gap corresponding to difference between gradual transition and accelerated transition. Additional gas volumes assumed not viable in line with continued non-commerciality of Barents Sea gas. Cost of conversion plants not included.
- **CCUS:** Total transportation and storage capacity in line with first two phases of Longship assumed, then building towards ~10 mtpa in 2030 and 100 mtpa in 2040. Capex of about 500 MUSD per mtpa of transportation capacity assumed, about 730 MUSD per mtpa of capturing capacity. Opex of 60 USD per tonne stored. Assumes 20% of capture done in Norway after Longship phase 2.
- **Offshore wind:** Installation cost of ~3 MUSD per MW and opex of 0.15 MUSD per MW per year assumed. 2 GW assumed installed by 2030 and ~16 GW by 2040.
- **Marine minerals**: Medium resource density and deposit spread assumed, 25 offshore projects in total by 2050. First minerals extracted in 2030.

Report contents

Steel footprint savings from subsea solution over fixed 5 times lower than annual op. emissions

Implied emissions footprint saving from development solutions
Thousand tonnes CO2 eq.

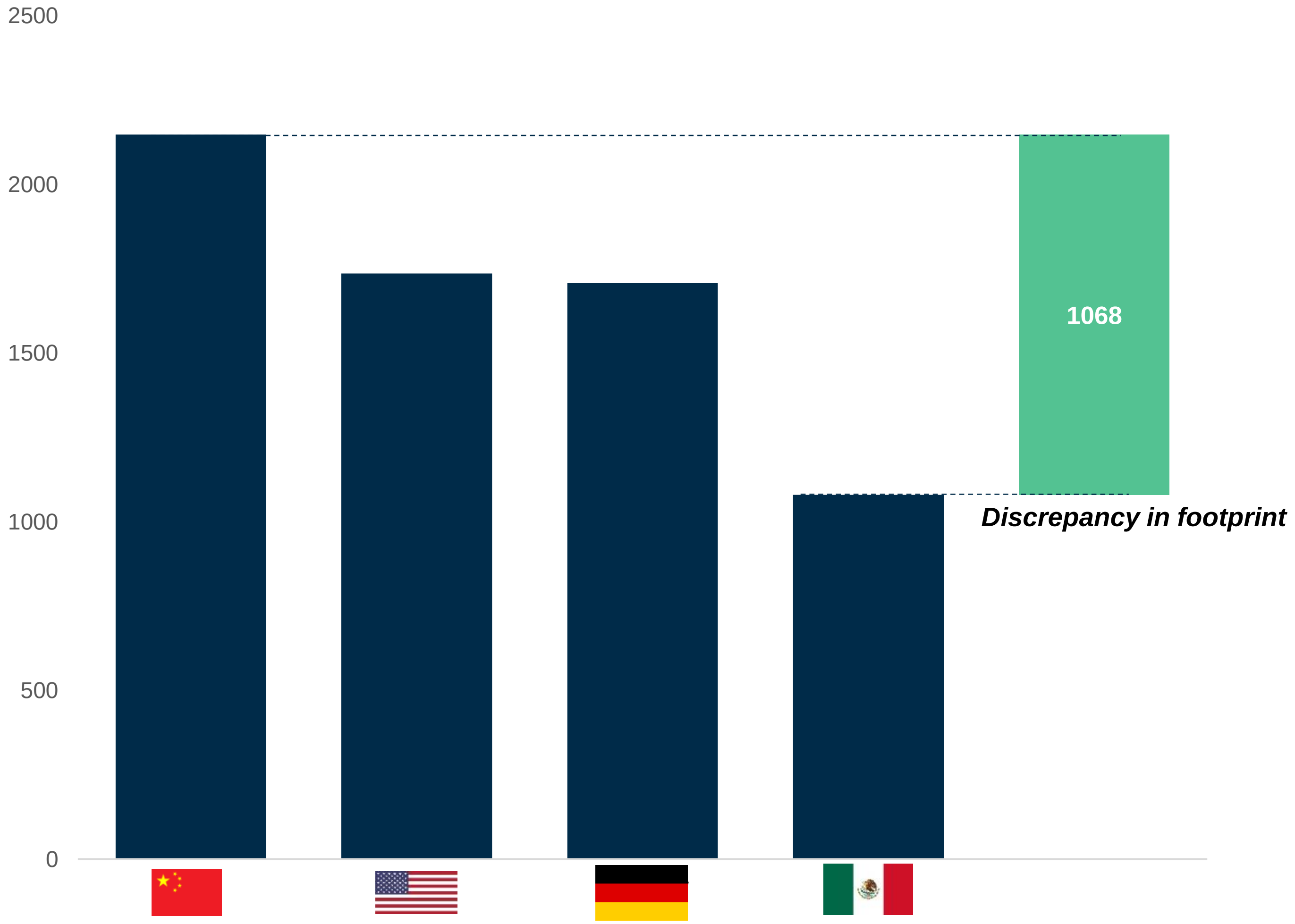


- Applying an average emissions intensity of steel produced in the United States and using the implied footprint on two types of development solutions suggests the reduction in footprint obtainable in choosing a subsea solution over a fixed jacket solution.
- A steel platform analogous to Edvard Grieg has a steel footprint of 64 ktonnes CO2. If a subsea development solution is chosen instead, the footprint is implied reduced by 95%.
- The ensuing reduction in footprint still only amasses to about 20% of one year of operational emissions from an asset of Edvard Grieg's size.

Footprint of steel assumed at 1700 kg CO2 per tonne steel
Source: Rystad Energy research and analysis; 2010 academic source

Large discrepancies in footprint of sources steel, about 50% reduction from highest to lowest

Production related emissions for steel manufacturing
Kg CO2 per tonne produced

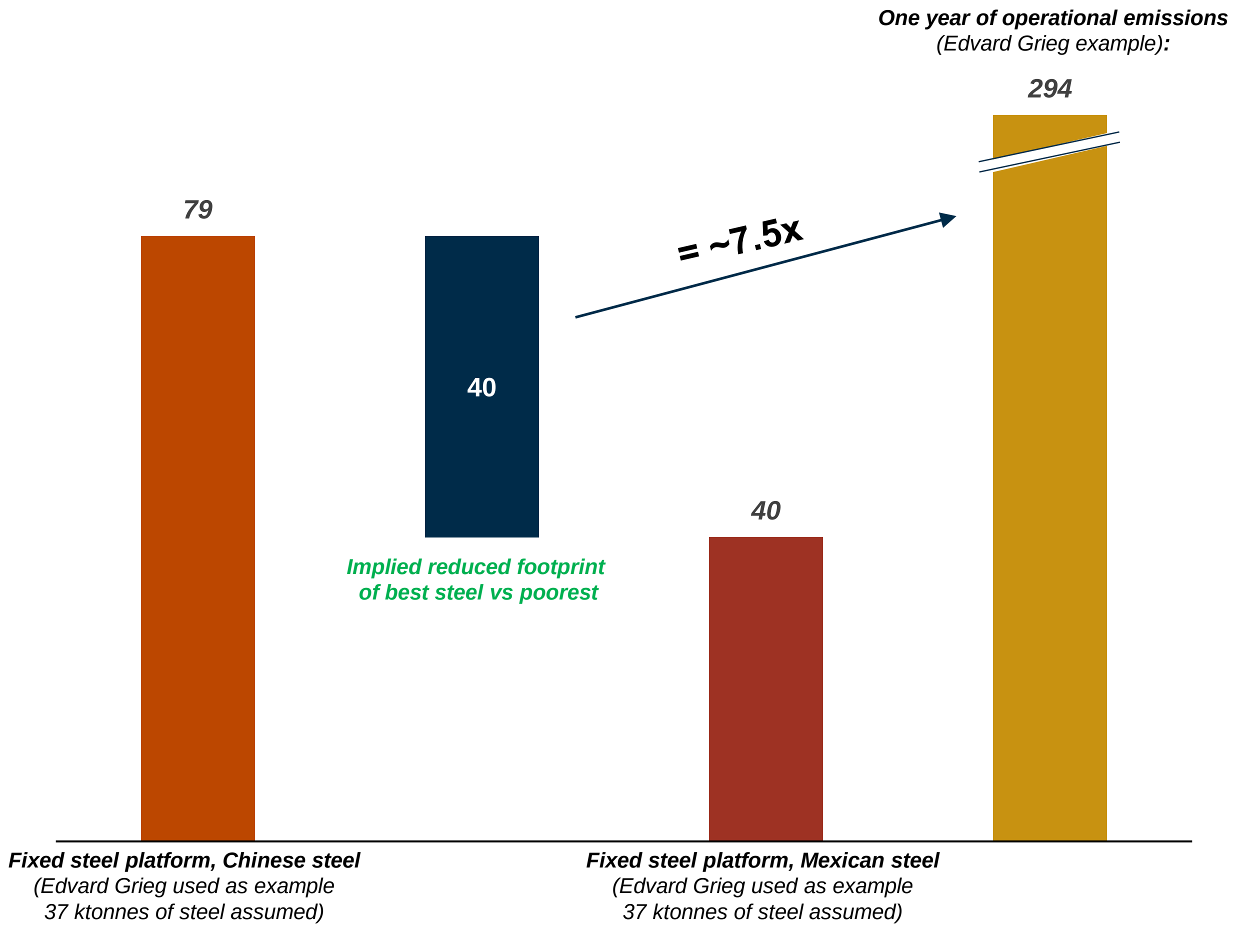


Footprint of steel assumed at 1700 kg CO2 per tonne steel
Source: Rystad Energy research and analysis; 2010 academic source

- Different sources of steel have varying manufacturing footprints in terms of CO2 intensity.
- The chart shows one source's reported differences in emissions, where Mexican steal appears to have about half the footprint of Chinese steel.
- Consequently, sourcing strategy for steel for oil and gas applications will imply a varying degree of CO2 footprint.

Sourcing best steel implies CO2 footprint saving equal to only 7.5x annual op. emissions

Implied additional emissions footprint from poorly sourced steel
Thousand tonnes CO2 eq.

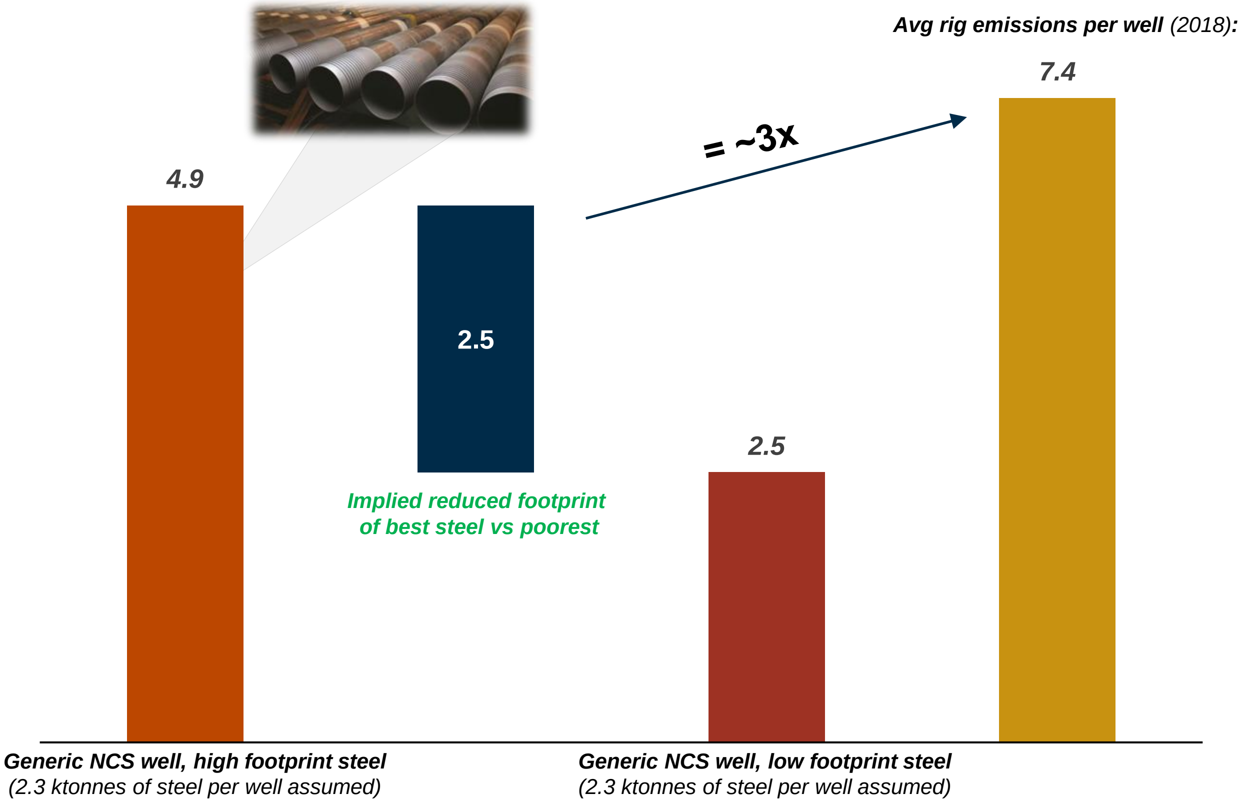


- The graph compares footprint of steel for an Edvard Greig size platform development using Mexican vs Chinese steel.
- The implied savings in footprint amass to about 7.5x annual operational emissions for a development of that size.
- This further implies that the choice of steel has little influence on the fields lifetime CO2 footprint.

Source: Rystad Energy research and analysis; 2010 academic source

Better steel sourcing with higher relative impact for wells, reduction potential ~3x rig emissions

Implied additional emissions footprint from poorly sourced steel
Thousand tonnes CO2 eq.



- Sourcing sustainable steel appears to have a larger effect in the case of wells.
- Choosing Mexican over Chinese steel in this case implies savings of about 30% of direct rig emissions associated with each well.

Source: Rystad Energy research and analysis; 2010 academic source

Platform facilities and wells chosen as O&G infrastructure assessed for potential re-use

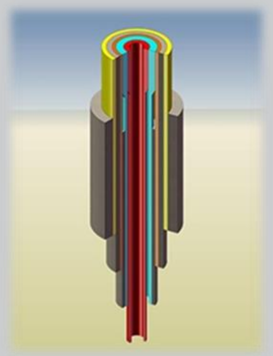
Circular applications of platform facilities

- Re-use of platform facilities is a relatively unproven concept on the NCS or elsewhere in the world.
- Among the challenges are integrity issues and a loss of bespokeness, which affects traditional metrics such as breakevens negatively.
- The exception is FPSOs, which in some cases have been redeployed successfully, albeit usually also with challenging economics.
- Given that integrity issues are accounted for, any new application requiring an offshore topside could re-use an abandoned O&G facility.
- If metrics relating to life cycle assessments are weighted more heavily in the coming years, this concept may have increased attractiveness beyond purely economic considerations

Relevant O&G opportunities	*Relevant NEM* opportunities*
• ***#2 Offshore CCS*** • ***#18 Material cond.*** • ***#29 Offshore smart grid***	• ***Offshore wind*** • ***Gas to wire***

Circular applications of wells

- Wells among the most cost intensive components of the offshore oil and gas business and expected to account for ~25% of costs on the NCS from 2021 to 2040.
- Consequently, in less opex and asset heavy industries like CCUS, wells are set to make up an even larger share of costs.
- As a result,. re-using wells potentially provides attractive overall economics for CCUS activities specific to oil and gas emissions, and CCUS as an independent industry.
- **This would imply future wells to be designed for re-usability, both taking length of life and corrosion issues related to CO2 into account.**
- Another possible re-use application may arise in the form of geothermal energy, tapped from already drilled wells.

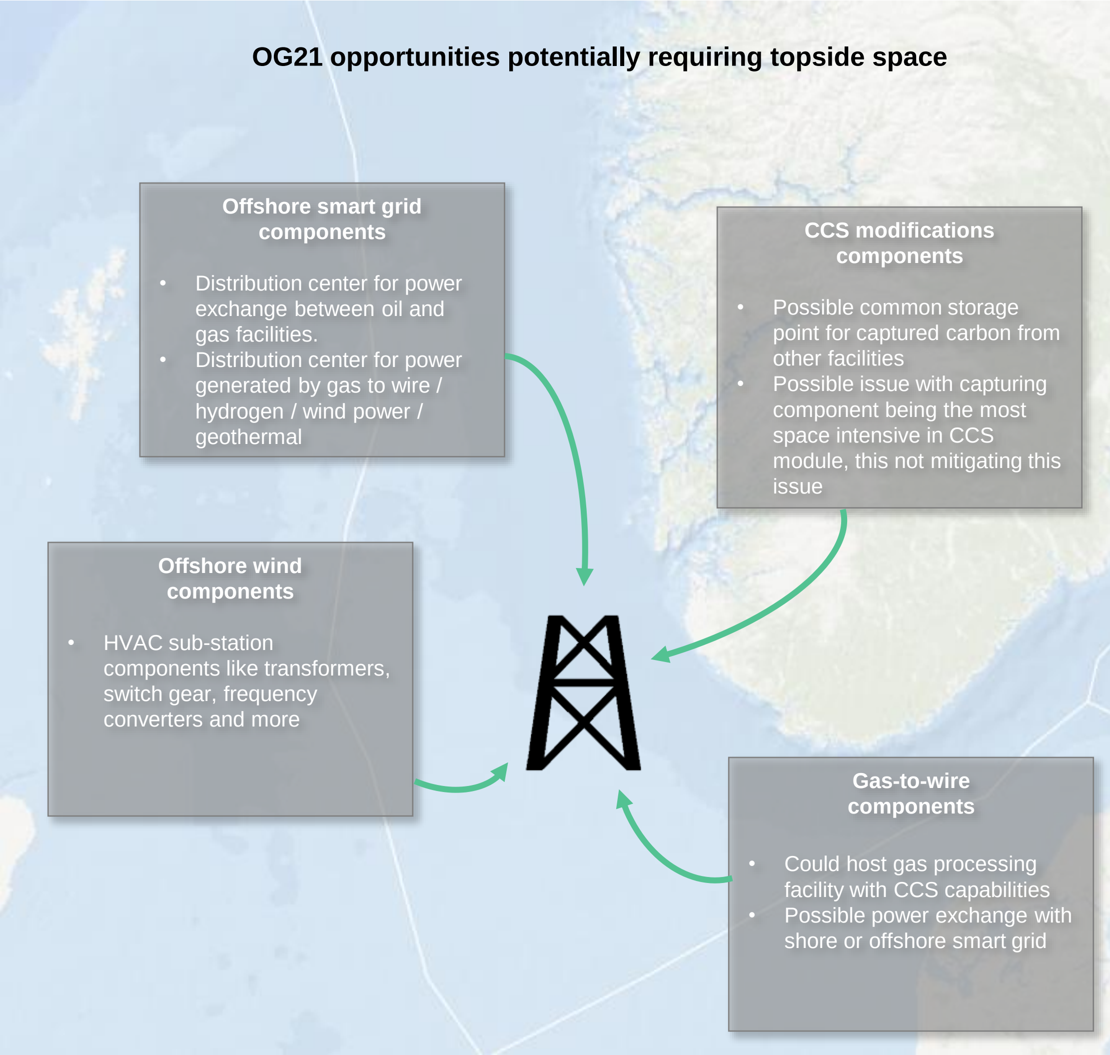


Relevant O&G opportunities	*Relevant NEM* opportunities*
• ***#2 Offshore CCS*** • ***#6 Offshore CO2 storage*** • ***#13 Advanced well constr.*** • ***#23 Standardized subsea templ.***	• ***CCUS*** • ***Geothermal***

*New energy markets

Source: Rystad Energy research and analysis; OG21 workshops

Multiple possible circular applications for platform facilities, but also many cons



OG21 opportunities potentially requiring topside space

Offshore smart grid components

- Distribution center for power exchange between oil and gas facilities.
- Distribution center for power generated by gas to wire / hydrogen / wind power / geothermal

CCS modifications components

- Possible common storage point for captured carbon from other facilities
- Possible issue with capturing component being the most space intensive in CCS module, this not mitigating this issue

Offshore wind components

- HVAC sub-station components like transformers, switch gear, frequency converters and more

Gas-to-wire components

- Could host gas processing facility with CCS capabilities
- Possible power exchange with shore or offshore smart grid

Value potential or re-used infrastructure

- *Reusability of 5 jacket facilities assumed by 2050*
- *Able to mitigate net 300 MUSD in EPC expenses per jacket*
- *Able to mitigate 64 ktonnes CO2 in manufacturing footprint, in line with footprint of steel in Edvard Grieg type platform with 1700 kg CO2 emitted per tonne of steel produced.*

*Cost savings potential**

1.5 BUSD

2021 to 2050

*Emissions reduction potential***

320 ktonnes CO2

2021 to 2050

Pros +	Cons -
Possible reduction of EPC costs for jackets. Mitigated GHG footprint of manufacturing new platform components Postponed and possibly shared cost of decom for operators	Integrity issues implies the persistence of an EPC scope and reduced safety Complication of decom process – Pioneering Spirit type solution no longer viable Requires timing fit between decom of original O&G facility and new purpose. Also contingent on geographical fit

*Includes only cost of EPC scope; **Not scope 1, but in terms of global emissions from reduced carbon footprint of procured steel.
Source: Rystad Energy research and analysis

Larger potential and fewer deal-breakers for the re-use of wells

OG21 opportunities potentially requiring wells

CCUS

- Wells needed to lead GHGs to underground deposits
- Require more corrosive resistant materials as compared to normal oil and gas wells

Geothermal

- Existing wells to be extended to become geothermal energy wells

Value potential or re-used infrastructure

- *Well cost of 90 MUSD per mtpa of storage capacity*
- *Storage capacity of 185 mtpa by 2050*
- *25% of CCUS wells able to be wells previously drilled for oil and gas extraction.*
- *1 well per 1.5 mtpa of storage capacity, emissions of 7.6 ktonnes CO2 per well.*

Cost savings potential
2.1 BUSD
2021 to 2050

*Emissions reduction Potential**
903 ktonnes CO2
2021 to 2050

Pros +	Cons -
• Mitigates large cost components for both geothermal and CCS leading to possible competitive advantage. • Possibility to contribute in offsetting emissions associated with original O&G extraction purpose of well • Postponed and possibly shared cost of decom for operators • Many wells still to be drilled on the NCS allowing for initial design toward circular features	• Integrity issues. • Likely to have higher expense if well is to be designed for multi purpose. Difficult in relation to NPV calculations. • Technical viability uncertain

*Scope 1
Source: Rystad Energy research and analysis