

Petrolia Noco

A proven explorer

- An NCS exploration company
- 20% partner in the Dugong discovery made in 2020
- We estimate a fair value range of NOK 3-12/share

An NCS exploration company focused on near-field drilling

Petrolia Noco is an NCS oil and gas exploration and production (E&P) company with nine exploration and two production licenses. Its primary focus in the oil and gas life cycle is the exploration phase, in particular in near-field exploration with the Tampen area in the North Sea being defined as the core focus.

20% partner in the Dugong discovery, three firm wells ahead

The company's main asset is its 20% partnered stake in the Dugong discovery, which has a gross recoverable resource estimate of 40-108mill boe. The partners on the discovery are currently maturing the discovery with the purpose of delivering a plan for development and operations (PDO) by YE'22, in order for the development to be covered by the favourable temporary tax regime on the NCS. Petrolia Noco has a firm commitment for three exploration wells: Dugong Tail, Molaris and Bounty. The first two will be drilled in 2021 while Bounty will be drilled in 2022. All three wells have a pre-drill resource range, which if successful would make a substantial contribution to our estimate for Petrolia Noco's asset base.

Fair value range of NOK 3-12/share

Our core NAV points to NOK 3.6-6.3/sh, with oil priced at USD 50-70/bbl. This is essentially all related to the Dugong discovery. Further to the core NAV we estimate that the risked exploration could add NOK 4-7/sh, assuming transaction prices of USD 2-4/boe. On an un-risked basis, the firm exploration programme could be as much as NOK 14-29/sh assuming a divestible value of USD 2-4/boe.

Taking into account that small E&Ps usually trade at a P/NAV of 0.5-0.8x we argue for a fair value range of NOK 3-12/sh for the next six months.

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NOKm	2019	2020	2021e	2022e	2023e
Sales	19	4	14	9	5
EBITDA	-85	-74	-323	-119	-40
EBITDA margin (%)	-438.6	-1,907.2	-2,388.3	-1,259.6	-722.6
EBIT adj	-88	-79	-325	-121	-41
EBIT adj margin (%)	-455.8	-2,019.5	-2,397.5	-1,282.0	-744.1
Pretax profit	-93	-87	-341	-142	-55
EPS rep	-0.18	-0.20	-0.52	-0.21	-0.06
EPS adj	-0.18	-0.20	-0.52	-0.21	-0.06
Sales growth (%)	na	-79.9	247.9	-30.3	-41.8
EPS growth (%)	high	-9.2	-155.7	58.7	73.1

Source: ABG Sundal Collier, Company data

Reason: Initiating coverage

Company sponsored research

Not rated

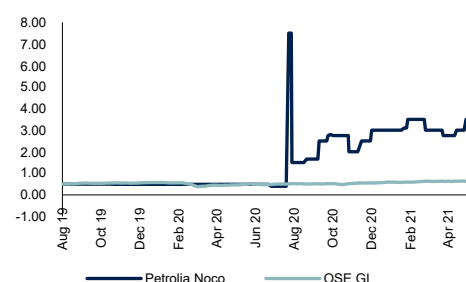
Share price (NOK) 27/05/2021 3.5
Fair value range (per share) 3-12

Oil & Gas, Norway
PNO.OL/PNO NO

MCap (NOKm) 500
MCap (EURm) 49
Net debt (EURm) 25

No. of shares (m) 145
Free float (%) 4
Av. daily volume (k) 0

Performance



1m 3m 12m
Absolute (%) 25.5 -1.4 604.1
Source: FactSet

	2021e	2022e	2023e
P/E (x)	-6.7	-16.2	-60.2
P/E adj (x)	-6.7	-16.2	-60.2
P/BVPS (x)	64.13	-21.63	-15.91
EV/EBITDA (x)	-2.3	-6.1	-21.3
EV/EBIT adj (x)	-2.3	-6.0	-20.7
EV/sales (x)	55.98	77.43	154.06
ROE adj (%)	-302.5	403.6	30.5
Dividend yield (%)	0	0	0
FCF yield (%)	-52.8	5.4	-23.0
Lease adj. FCF yld (%)	-52.8	5.4	-23.0
Net IB debt/EBITDA	-0.8	-1.9	-8.7
Lease adj. ND/EBITDA	-0.8	-1.9	-8.7

Please refer to important disclosures at the end of this report

This research product is commissioned and paid for by the company covered in this report. As such, this report is deemed to constitute an acceptable minor non-monetary benefit (i.e. not investment research) as defined in MiFID II.

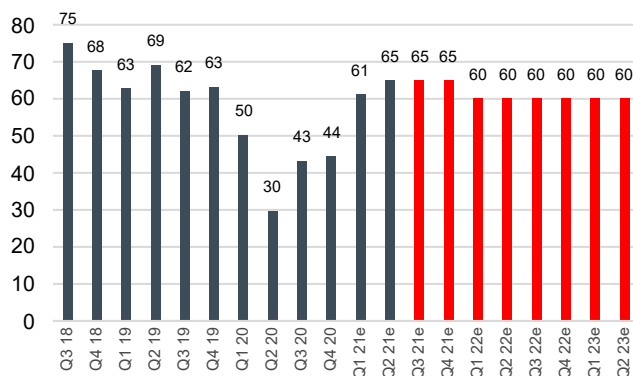
Company description

Petrolia Noco is an NCS oil and gas exploration and production (E&P) company. Its primary activity in the oil and gas life cycle is the exploration phase, in particular in near-field exploration, with the Tampen area in the North Sea being defined as the core focus.

Risks

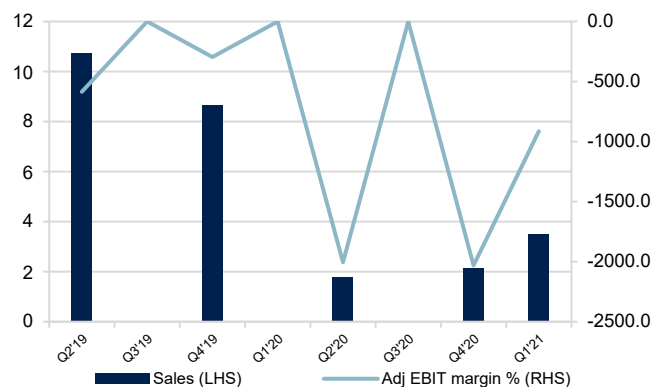
The main risk in the case is related to exploration success in its drilling programme, as well as successfully maturing the Dugong discovery. Other risks relate to funding requirements and limited liquidity in the share.

Oil price estimates (Brent USD/bbl)



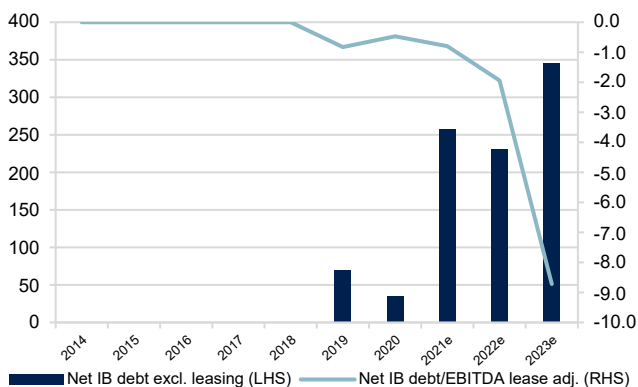
Source: ABG Sundal Collier, Company data

Quarterly sales and adj. EBIT margin



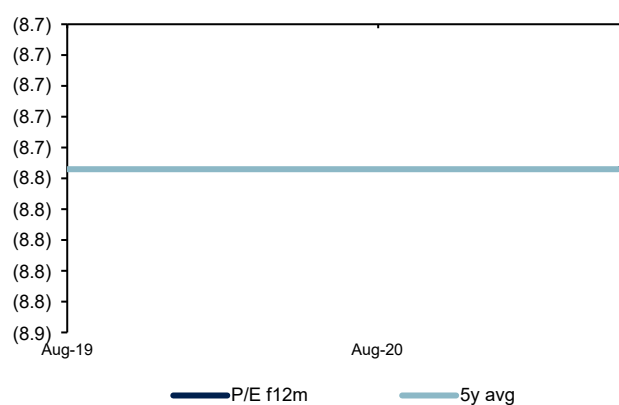
Source: ABG Sundal Collier, Company data

Lease adj. net debt and ND/EBITDA



Source: ABG Sundal Collier, Company data

12-month forward-looking P/E



Source: ABG Sundal Collier, Company data

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Investment summary

As a small NCS E&P, Petrolia Noco made its mark in 2020 as a partner in the sizable Dugong discovery. We like Petrolia Noco's strategy of utilizing available technology in addressing exploration near existing infrastructure, with a primary focus on the Tampen area in the northern North Sea. We estimate a core NAV of NOK 3.6-6.3/sh based on long-term oil prices of USD 50-70/bbl. Further to this, there could be upside to our NAV on exploration success. The risk value of exploration makes up NOK 4-7/sh, while on an un-risked basis it could be in the range of NOK 14-29/sh, assuming transaction pricing of USD 2-4/boe. Smaller E&Ps currently trade at a P/NAV of 0.5-0.8x. Consequently, we have a valuation range of NOK 3-12/sh. The main risk to our valuation range is the successful maturing of Dugong to PDO by YE'22 and at some point monetizing the discovery, as well as exploration success.

Petrolia Noco in brief

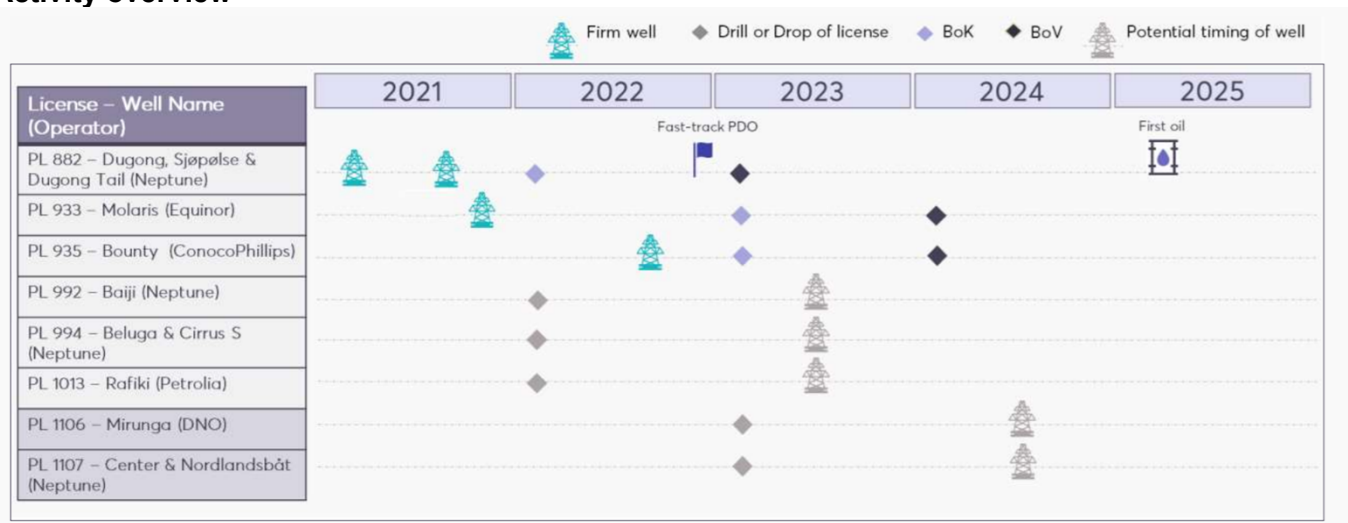
Petrolia Noco is an NCS oil and gas exploration and production (E&P) company with nine exploration and two production licenses. Its primary focus in the oil and gas life cycle is the exploration phase, in particular in near-field exploration with the Tampen area in the North Sea being defined as the core focus.

The company's main asset is its 20% partnered stake in the Dugong discovery, which has a gross recoverable resource estimate of 40-108mill boe. The partners on the discovery are currently maturing the discovery with the purpose of delivering a plan for development and operations (PDO) by YE'22, in order for the development to be covered by the favourable temporary tax regime on the NCS.

Petrolia Noco has a firm commitment for three exploration wells: Dugong Tail, Molaris and Bounty. The first two will be drilled in 2021 while Bounty will be drilled in 2022. All three wells have a pre-drill resource range, which if successful would make a substantial contribution to our estimate for Petrolia Noco's asset base.

In addition to maturing the Dugong discovery and its exploration activities, Petrolia Noco has a minor production of 65boe/d from its working interest in the Enoch and Flyndre fields in 2021e. This position generates some cash flow and helps develop the Petrolia Noco organization's capabilities.

Activity overview



Source: ABG Sundal Collier, company data

The company

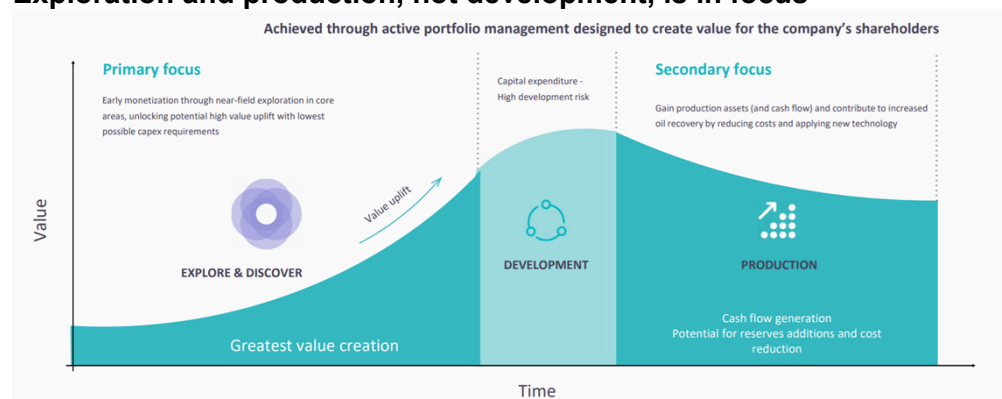
Overview

Petrolia Noco is a Norway (Bergen) based oil and gas E&P company with one operated license, plus partner stakes in 11 assets. The main asset of the company is the 20% interest in the Dugong oil discovery, which was made in the Tampen area offshore from Norway in 2020. It holds a small position in two producing assets (4.36% in Enoch and 0.825% in Flyndre), with a net 2021e production of 65 boe/d, generating some cash flow. Relative to the size of the company we find that beyond the Dugong discovery, the exploration exposure to the Tampen area is the most interesting. All of Petrolia Noco's operations are on the Norwegian Continental Shelf.

Exploration strategy

Petrolia Noco has an expressed strategy of value creation through the drill bit, identifying and drilling exploration prospects, predominantly in the Tampen Area. The secondary focus relates to the production of oil and gas, while it generally would not seek to engage in participating in the development phase of a field, due to the combination of capital intensity and project risk. Given the size of the company, we find this strategy sensible, as it requires specialized capabilities and it is not an extensive organisation.

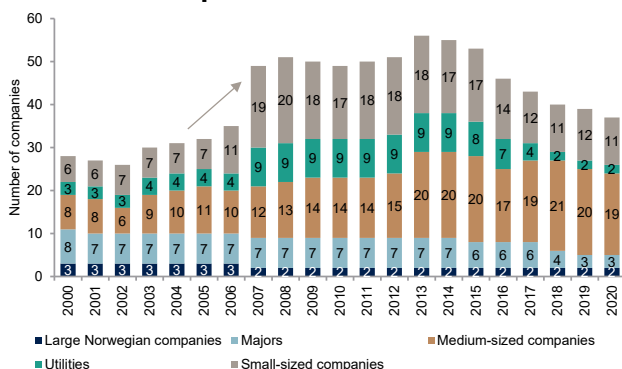
Exploration and production, not development, is in focus



Source: Company data

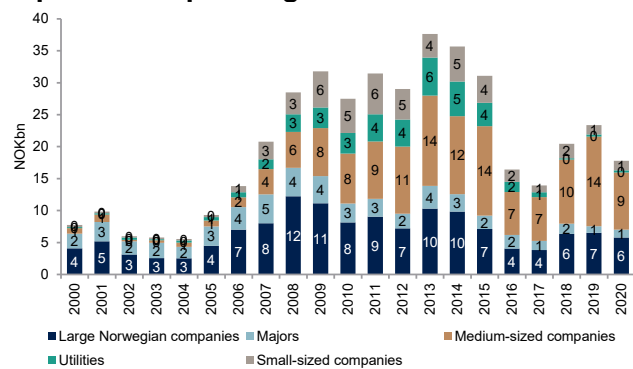
The strategy is supported by the exploration tax regime in Norway, where 78% of exploration spending is reimbursed from the tax bill in the following year's Q4. The exploration tax regime was introduced in Norway in 2005 to stimulate exploration of oil and gas and to facilitate smaller, specialized companies with no production to participate in exploration activities.

Number of companies on the NCS



Source: ABG Sundal Collier, company data

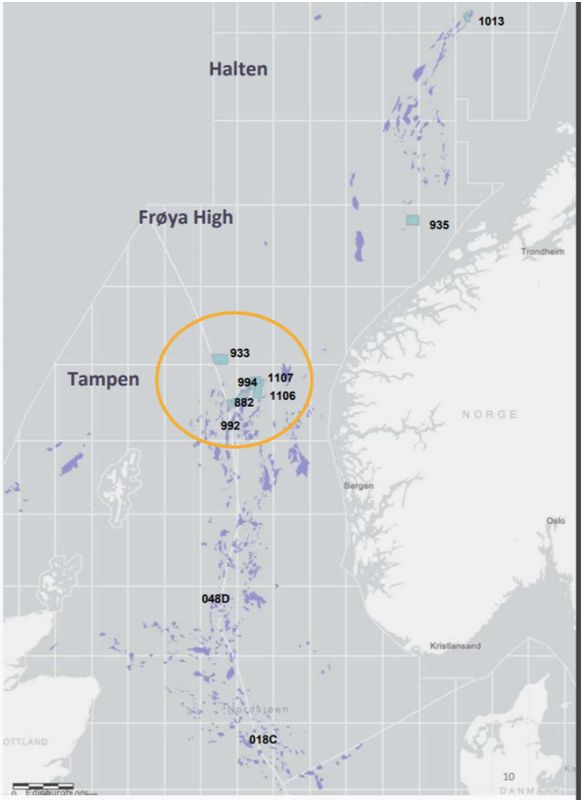
Exploration spending on the NCS



Source: ABG Sundal Collier, company data

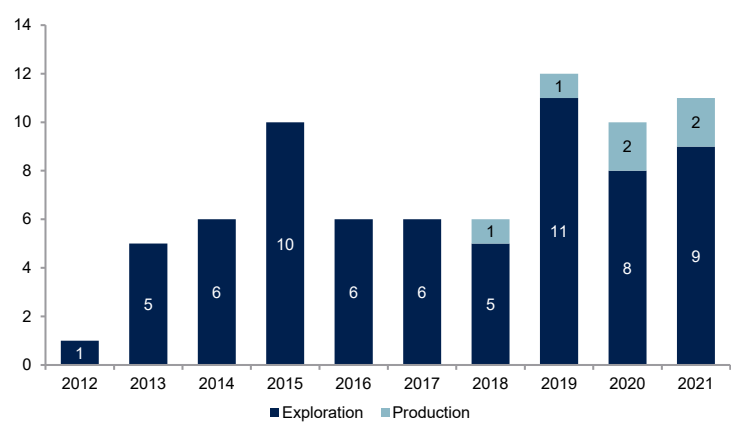
The key exploration focus area for Petrolia Noco is the Tampen area in the Northern part of the North Sea. In this area we find large, mature, fields such as Statfjord, Gullfaks and Snorre. The presence of existing infrastructure, with capacity for additional volumes, lowers the bar for a discovery to be commercially viable as it can limit capex requirements and can result in a shorter lead time from discovery to production. Consequently, smaller discoveries can be economically viable.

Petrolia Noco license map



Source: Company data

License portfolio



Source: Company data

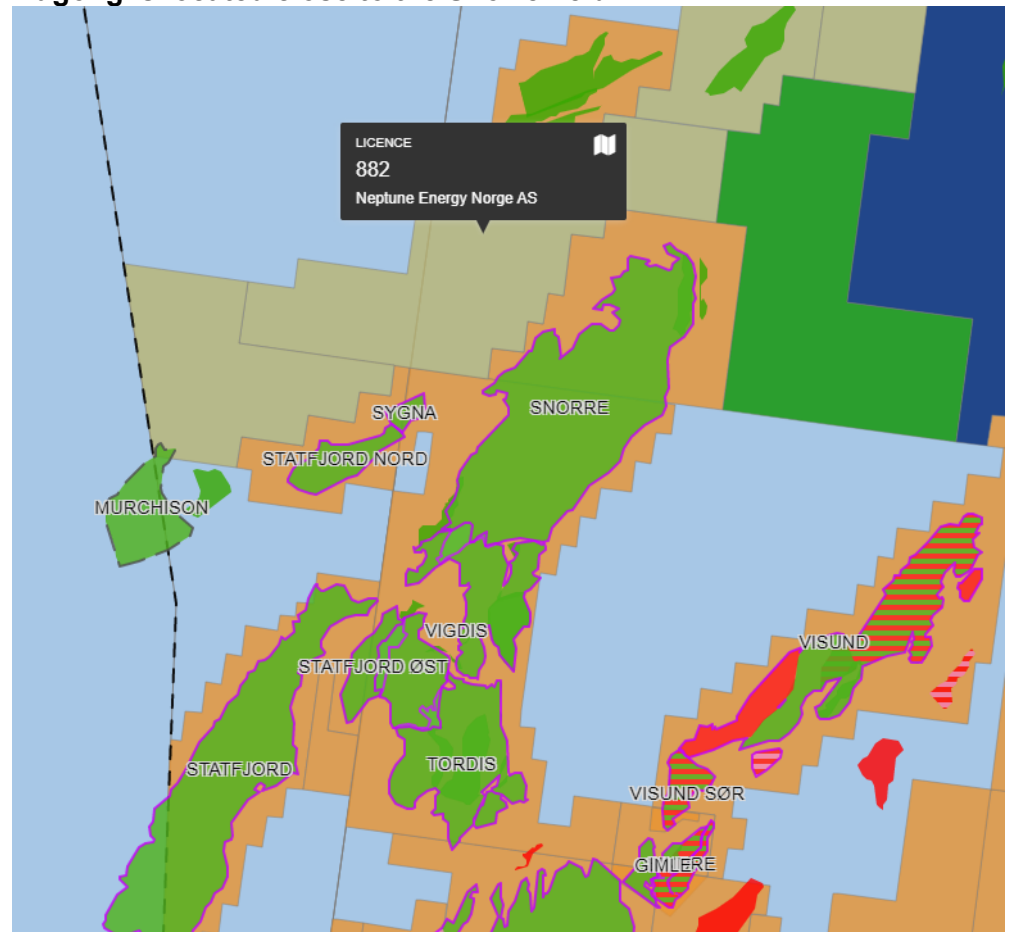
The assets

Dugong

The Dugong discovery is located 158km west of Florø, Norway, at a water depth of 330 metres. The reservoir lies at a depth of 3,250-3,500m. The operator is Neptune Energy (45%). The partners are Petrolia Noco (20%), Idemitsu Petroleum (20%) and Concedo (15%).

The Dugong discovery was one of the largest discoveries on the NCS in 2020. A discovery on the prospect was first announced on 3 July 2020 and on 4 August 2020, Neptune and its partners provided the first resource estimate of the gross resource range, which was 40-120mill boe. Following the drilling of an appraisal well in Q1'21, the resource range was revised to recoverable gross resources of 40-108 mill boe. The Dugong Tail prospect will be drilled later in 2021 and can add additional volumes to improve economics further.

Dugong is located close to the Snorre field



Source: ABG Sundal Collier, NPD

The timeline on Dugong involves maturing the discovery towards concept selection by the end of 2021 and plans for development and operations (PDO) by YE'22, with approval by YE'23 to be eligible to be developed under the favourable temporary tax on the NCS. To our understanding, there are three main concepts being considered:

- 1) ~10km subsea tie-back to the Snorre production facilities,
- 2) ~35km subsea tie-back to the Statfjord C production facilities (the same facilities as used for the Statfjord Nord, Statfjord Øst and Sygna fields).
- 3) re-deployment of the Knarr FPSO (the FPSO is under contract with Shell until March 2022).

In our view, a tie-back solution to Snorre or Statfjord C appears the most likely due to:

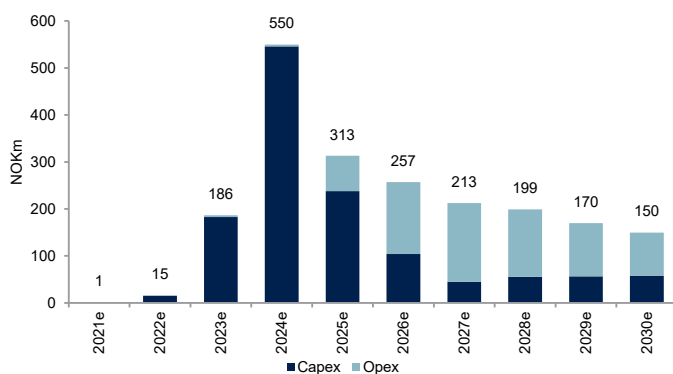
- It is the closest field, and the Snorre expansion project commenced production in December 2020. The project extends productive life for the Snorre field through 2040. This is further supported by the fact that the reference oil quality in the Dugong discovery is the Snorre B.
- Equinor has recently announced it will extend the life of Statfjord C to 2040 through a NOK 3bn gas lift project that was announced in December 2020.
- There are potentially several interested parties in the Knarr FPSO. For example, Equinor might look to use it for its development of the Rosebank field in the UK, according to industry newspaper Upstream¹.

In the following, we have based our estimates on production and cost assumptions from Rystad Energy. In brief, it implies gross recoverable resources of 74mill boe (mid-point of the operators resource estimate), of which 85% are liquids.

Unit opex is assumed at ~USD 9/boe and capex of ~USD 12/boe.

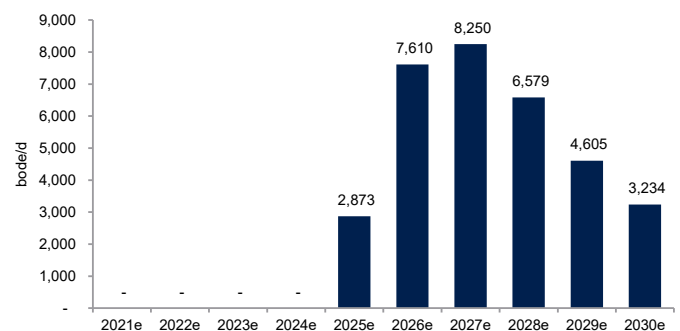
Petrolia Noco has guided potential production could start in 2025.

Net capex and opex (pre-tax)



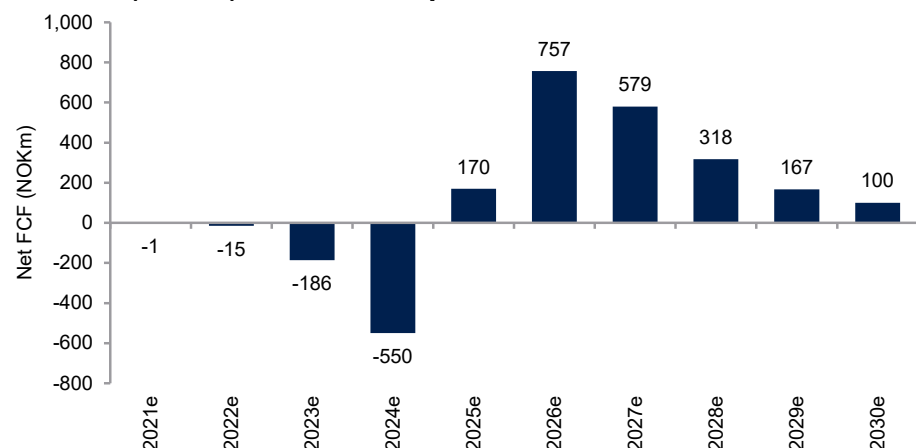
Source: ABG Sundal Collier, Rystad

Net production



Source: ABG Sundal Collier, Rystad

Net FCF (NOKm), ABGSCe oil price



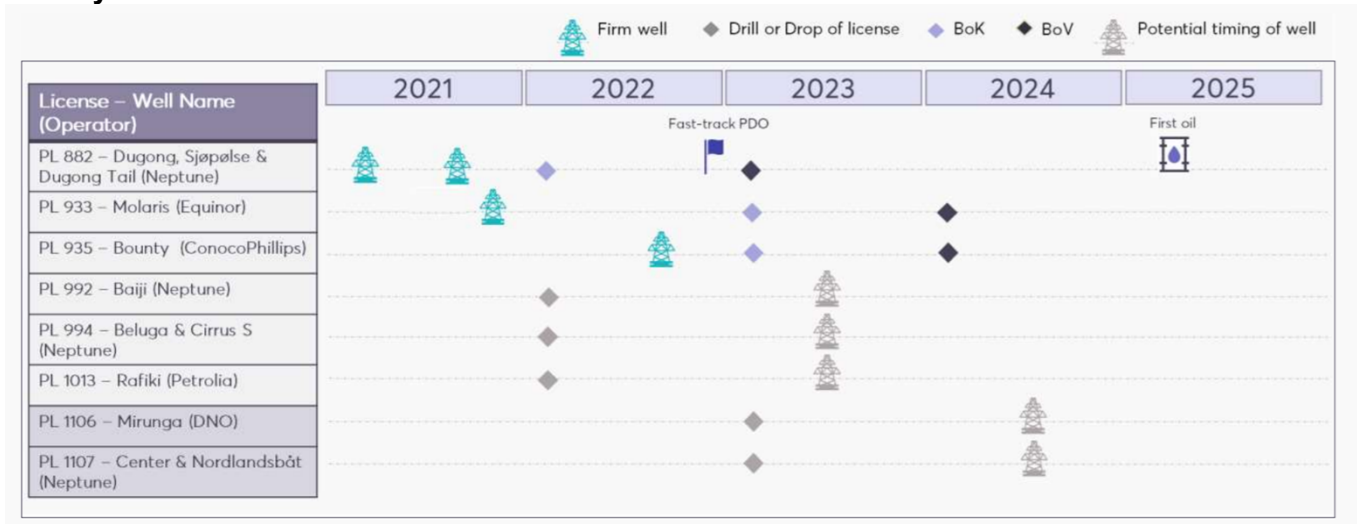
Source: ABG Sundal Collier, Rystad

¹ <https://www.upstreamonline.com/field-development/equinor-steps-up-at-rosebank-as-focus-falls-on-knarr-fps0/2-1-901766>

Exploration activity

Naturally, an important part of the Petrolia Noco story is its exploration efforts. Petrolia Noco has three firm wells in its drilling programme; Dugong Tail, Molaris and Bounty. All three wells are operated by strong players on the NCS; Neptune, Equinor and ConocoPhillips. In addition to the firm exploration program, Petrolia Noco holds stakes in several licenses on the NCS where there potentially could be exploration drilling in the next couple of years. Given that the partnerships for these wells have not yet been agreed, we have not included it in our report.

Activity overview



Source: ABG Sundal Collier, company data

The table below shows company guidance on key parameters for the firm exploration programme.

Key data on the firm exploration programme

		Prospect		
	Scenario	Dugong Tail	Molaris	Bounty
License		PL 882	PL 933	PL 935
Operator		Neptune	Equinor	ConocoP.
Timing		Q3'21	Q4'21	Q3/Q4 '22
Gross unrisked, MMboe	Low	36	13	18
	Mid	114	154	153
	High	197	658	665
PNO share		20%	40%	20%
Net estimated well cost, NOKm	Dry	70	120	30
	Discovery	160	160	40
Chance of Success		36%	25%	16%
Net unrisked, MMboe	Mid	22.8	61.6	30.6
Net risked, MMboe	Mid	8.2	15.4	4.9

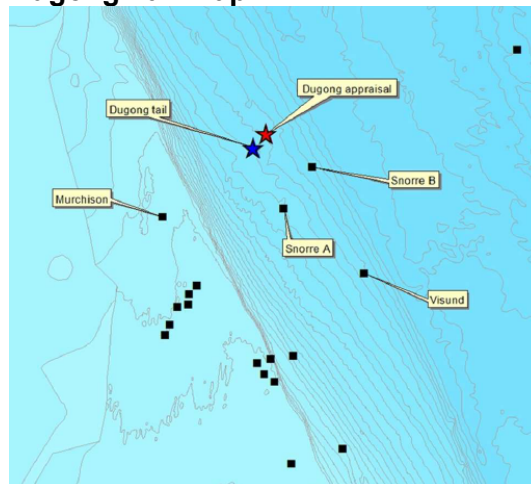
Source: ABG Sundal Collier, company data

Dugong Tail

In our view, the most interesting of these exploration wells is the upcoming Dugong Tail. This well will be drilled in Q3'21 and, according to the drilling application, the well including sidestep is estimated to last for 78 days (42 days for the main well and a further 36 days for the sidestep). This well is located close to the recent Dugong discovery and if it turns out to be a success it could potentially add material resources to the area and further improve economics for the license as a whole.

It is worth highlighting that in its communication, Neptune Energy, the operator on the license, uses a prospective resource estimate on the Dugong Tail prospect of 33 million boe. This is materially lower than the resource estimates that Petrolia Noco operates with, of 36-114-197 million boe for low-mid-high cases. It is our understanding that the differences in the resource estimates evolve around what has been included in the estimates. Neptune's estimate is supposedly related to only one of the structures, while Petrolia Noco has included the structures that will be tested in the exploration drilling when also taking to account the sidestep.

Dugong Tail map



Source: ABG Sundal Collier, Akvaplan

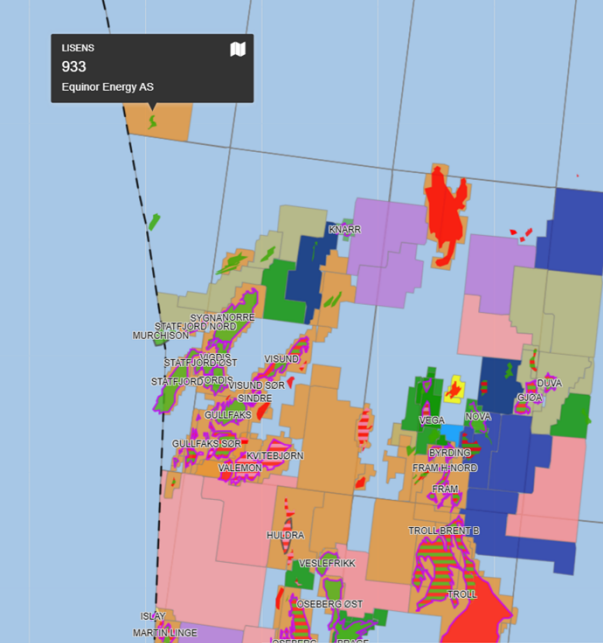
Molaris

Molaris appears an interesting exploration prospect in the sense that Petrolia Noco holds a material 40% stake in the well, which has a material pre-drill resource range of 13-154-658 million boe on a gross basis. The pre-drill chance of success also appears to be decent, estimated at 25%. Given its location, the prospect fits well with Petrolia Noco's focus on the Tampen area, and it could potentially be a tie-back to Dugong. There is limited data available on the prospects.

Bounty

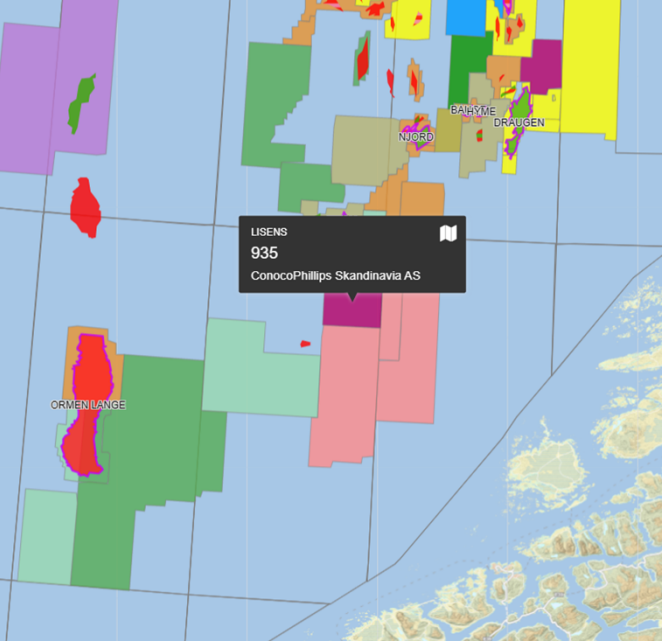
Bounty is within the near-field exploration strategy of Petrolia Noco, albeit it is not located in its core exploration area; Tampen. The pre-drill chance of success of 16% is lower than that of Dugong Tail and Molaris, however this is offset by the substantially lower estimated drilling cost at NOK 30-40m, making the well a fair option. There is limited data available on the prospects.

Map of the license with Molaris prospect



Source: ABG Sundal Collier, NPD

Map of the license with Bounty prospect



Source: ABG Sundal Collier, NPD

Beyond the firm well program

With a total of nine exploration licenses, and a further two production licenses, there is likely to be activity beyond the current firm well program. We have not included this in our estimates as of now.

The table below shows the potential prospects that Petrolia Noco could participate in over time, located in what it has been defined as the Greater Dugong area.

Greater Dugong area

Area		Gross Unrisked Recoverable Volumes ¹
		Mill BOE
 PL 882 Dugong		40-108
 PL 882 Dugong Tail		36-197
 PL 933 Molaris		13-658
PL 992 Baji		15-70
PL 994 Beluga		14-58
PL 1106 (APA 20)		33-365
PL 1107 (APA 20)		26-256



Greater Dugong Area

Source: ABG Sundal Collier, company data

Enoch & Flyndre

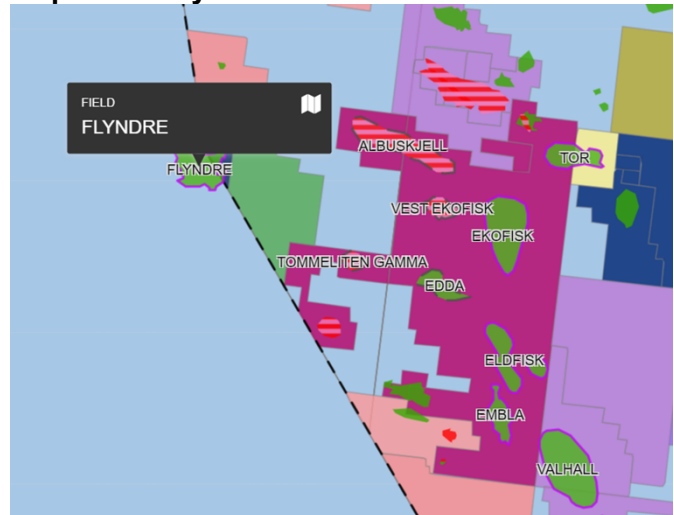
Petrolia Noco holds partner interest in the producing Enoch and Flyndre fields. Both fields are on the UK border. Petrolia Noco holds 4.36% in the Repsol operated Enoch field (21.8% of the Norwegian part of the field), and 0.83% in the NEO Energy operated Flyndre field (11.65% in the Norwegian part of the field). Total production from the fields account for 65 boe/d in 2021e. Enoch is expected to produce until 2023, while Flyndre is expected to produce until 2025. The stakes in the fields do not constitute a material value in our valuation.

Map of the Enoch field



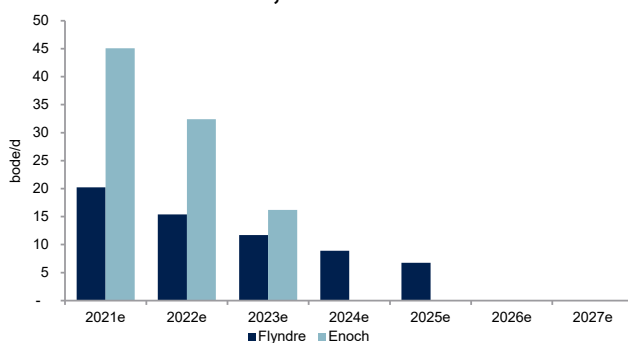
Source: ABG Sundal Collier, NPD

Map of the Flyndre field



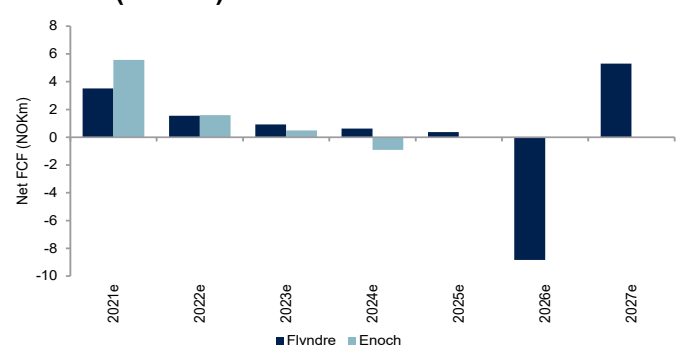
Source: ABG Sundal Collier, NPD

Production estimates, net



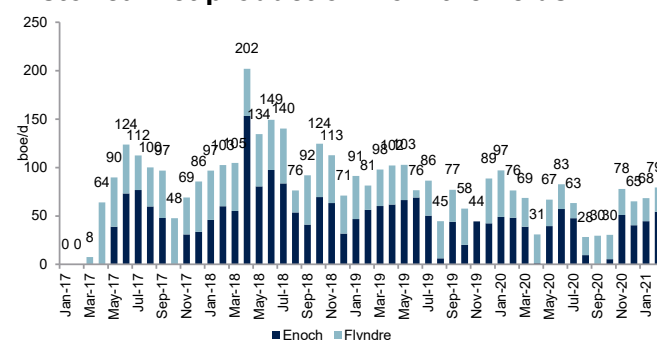
Source: ABG Sundal Collier, NPD

Net FCF (NOKm)



Source: ABG Sundal Collier, company data

Historical net production from the fields



Source: NPD

Estimates

Our key estimates are outlined in the table below. We have based our estimates on the base case drilling costs for the firm exploration programme. It is important to highlight the beneficial exploration refund scheme in Norway resulting in 78% of exploration spending being refunded in cash over the tax bill. Detailed estimates on Dugong, Enoch and Flyndre have been discussed in previous sections.

Key estimates

Petrolia Noco													2019	2020	2021e	2022e	2023e	2024e	2025e	
NOkm	H2'19	H1'20	H2'20	H1'21e	H2'21e	H1'22e	H2'22e	H1'23e	H2'23e	H1'24e	H2'24e	H1'25e	H2'25e							
Income Statement																				
Net sales	9	2	2	7	7	5	5	4	1	1	1	266	269	19	4	14	9	5	2	535
EBITDAX	-3	-8	-18	-14	-14	-16	-16	-19	-21	-1	-1	228	231	-17	-25	-28	-33	-40	-3	459
EBITDA	-23	-34	-40	-65	-258	-46	-73	-19	-21	-1	-1	228	231	-85	-74	-323	-119	-40	-3	459
EBITDA margins	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	86%	86%	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	86%
EBIT	-26	-35	-43	-65	-259	-47	-74	-20	-21	-1	-2	169	171	-88	-79	-325	-121	-41	-3	341
EBIT margins	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	64%	64%	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	64%
PTP	-29	-39	-48	-71	-270	-61	-81	-26	-28	-2	-2	169	171	-93	-87	-341	-142	-55	-3	340
Tax	21	28	31	55	211	48	63	22	25	7	11	-120	-120	71	60	266	111	46	18	-240
Net profit	-8	-11	-16	-15	-59	-13	-18	-5	-4	5	9	49	51	-22	-27	-75	-31	-8	15	100
# avg. shares	61	61	67	139	145	145	145	145	145	145	145	145	145	121	133	145	145	145	145	145
EPS (NOK)	-0.14	-0.18	-0.24	-0.11	-0.41	-0.09	-0.12	-0.03	-0.03	0.04	0.06	0.34	0.35	-0.18	-0.20	-0.52	-0.21	-0.06	0.10	0.69
Key BS and CF figures																				
Gross interest bearing debt	95	135	55	153	273	132	132	132	0	0	0	0	0	95	55	273	132	0	0	0
Gross cash	21	10	18	33	13	5	-101	-218	-348	-623	-866	-757	-683	21	18	13	-101	-348	-866	-683
NIBD	74	125	37	120	260	127	233	350	348	623	866	757	683	74	37	260	233	348	866	683
NIBD/share (NOK)	11	21	5	8	16	8	14	22	22	39	54	47	42	5	3	16	14	22	54	42
Book equity	27	16	42	67	8	-6	-23	-28	-31	-26	-17	32	84	27	42	8	-23	-31	-17	84
Book equity/share (NOK)	4	3	6	4	0	0	-1	-2	-2	-2	-1	2	5	2	3	0	-1	-2	-1	5
Operating cash flow	14	-31	98	36	186	181	-23	-25	93	-1	30	228	193	-43	67	222	158	67	28	421
Free cash flow	12	-50	47	-124	-140	133	-106	-117	1	-274	-243	109	74	-45	-2	-264	27	-115	-518	184
Free cash flow/share (NOK)	0.2	-0.8	0.7	-0.9	-1.0	0.9	-0.7	-0.8	0.0	-1.9	-1.7	0.8	0.5	-0.4	0.0	-1.8	0.2	-0.8	-3.6	1.3
Other key figures and assumptions																				
	H2'19	H1'20	H2'20	H1'21e	H2'21e	H1'22e	H2'22e	H1'23e	H2'23e	H1'24e	H2'24e	H1'25e	H2'25e	2019	2020	2021e	2022e	2023e	2024e	2025e
Brent	63	40	44	63	65	60	60	60	60	60	60	60	60	64	42	64	60	60	60	60
Realised price/boe (USD)	81	16	22	63	65	60	60	60	60	60	60	56	56	76	19	64	60	60	60	57
NOK/USD	9.0	10.2	9.2	8.8	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	8.8	9.7	8.9	9.0	9.0	9.0	9.0
EPS (NOK)	-1.2	-1.8	-2.2	-1.0	-3.7	-0.8	-1.1	-0.3	-0.2	0.3	0.6	3.0	3.2	-1.6	-2.0	-4.6	-1.9	-0.5	0.9	6.2
Field-by-field production (boe/d):																				
Enoch	35	39	26	47	44	32	32	32	0	0	0	0	0	47	32	45	32	16	0	0
Flyndre	32	31	23	23	18	17	14	13	10	10	8	8	6	32	27	20	15	12	9	7
Dugong	0	0	0	0	0	0	0	0	0	0	0	2,873	2,873	0	0	0	0	0	0	2,873
Total production	66	70	49	69	61	50	46	45	10	10	8	2,881	2,879	79	60	65	48	28	9	2,880
Of which is gas	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	15%	15%	0%	0%	0%	0%	0%	0%	15%
Other key figures:																				
Unit production costs/boe (USD)	53	-4	10	-9	-10	-13	-14	-40	-130	-134	-169	-8	-8	-6	3	-9	-14	-57	-148	-8
Depreciation cost/boe (USD)	-23	-10	-35	0	-12	-13	-14	-14	-10	-10	-10	-12	-12	-13	-22	-6	-13	-13	-10	-13
Capex (NOKm)	0	0	0	0	0	-8	-8	-91	-91	-273	-273	-119	-119	0	0	-1	-16	-183	-546	-238
Exploration spending (NOKm)	-21	-45	-73	-160	-325	-40	-75	0	0	0	0	0	0	-70	-122	-486	-115	0	0	0

Source: ABG Sundal Collier, company data

For 2021, our estimates are close to guidance, as the main items relate to exploration spending.

ABGSC vs. guidance

Key estimates		2021 guidance	2021 ABGSCe	2022 ABGSCe
Production	boe/d	60-80	65	48
G&A	NOKm	40-45	40	40
Exploration expenses ex wells	NOKm	130-150	140	80
Wells (Dry-Success)	NOKm	240-450	345	35
Fiscal refunds	NOKm	300-500	422	121

Source: ABG Sundal Collier, company data

We observe that Petrolia Noco has a funding gap to meet its current activity plans. The size of the funding gap is dependent on 1) exploration spending outcome, where discoveries require more funding as it entails additional work, and 2) how Petrolia Noco proceeds with monetizing through a divesture or holding its position in Dugong through the development phase.

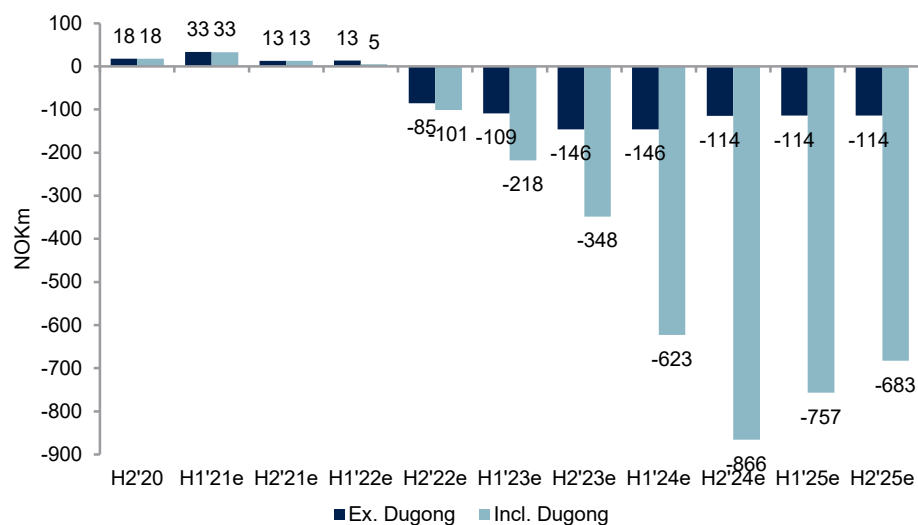
Petrolia Noco has stated it intends to hold its position in Dugong through the PDO (by YE'22), but that it also wants to hold its position towards production. This is in contrast with the original strategy of not holding discoveries through to development.

If Petrolia Noco holds its 20% position in the discovery through to development, we estimate a funding gap of ~NOK 870m with a peak in H2'24, just before production is expected to start.

However, if it divests its position, we estimate a funding gap (excluding any proceeds from divesture) of ~NOK 150m in H2'23e. In both scenarios we see a need for additional liquidity in H2'22e, assuming that gross debt is equal to 95% of the outstanding exploration refunds.

As we have used mid-point cost estimates in our modelling, the funding gap can increase under exploration success scenarios as discoveries require additional work and consequently more spending than dry wells. However, if exploration turns out to be successful, additional funding is also likely to become more available.

Gross cash estimate



Source: ABG Sundal Collier, company data

In the going concern statement in the 2020 annual report, the Board stated the following:

“The Company is committed to further exploration activities in 2021. The financial position and the liquidity of the company are considered to be manageable in relation to planned activity level, through a combination of funds covered by existing loan facilities (refer to note 20) and available liquidity from main shareholders. The main shareholders have expressed willingness and documented capacity to provide funding of the remaining activities.”

It also stated:

“At the reporting date the main shareholders have expressed willingness and documented capacity to provide funding of the remaining activities estimated to NOK 250-300 million. The main shareholders are also positive to potential new equity and debt investors.”

At the end of 2020, NOK 41m in equity was raised at NOK 3.5/sh. With these commitments from the main shareholders, we read that Petrolia Noco should have access to capital for its exploration commitments. To bring Dugong to production will require substantial additional funding.

Valuation

For oil companies such as Petrolia Noco, we argue that a net asset value (NAV) valuation method is the most relevant. We estimate a YE'21 NAV of NOK 5.0/sh, based on ABGSCe's oil price assumption of USD 60/bbl long term. It is important to emphasise that the NAV is dependent on Petrolia Noco being able to fund its part of the development capex or monetize the Dugong discovery. If we backsolve for a discounted oil price (oil price required for P/NAV of 1.0x), we argue that an oil price of USD ~50/bbl is discounted in Petrolia Noco.

NAV sensitivity to different oil prices

Petrolia Noco NAV YE 2021								Oil price sensitivity					
Field	License	Operator	Location	Net unrisked, MMboe	Prob	MMboe	USD/bbl	ABGSCe NOK/sh	USD40 NOK/sh	USD50 NOK/sh	USD60 NOK/sh	USD70 NOK/sh	USD80 NOK/sh
Producing assets													
Enoch	PL 048D	Repsol	Norway	0	100%	0	16.8	0.0	0.0	0.0	0.0	0.0	0.0
Flyndre	PL 018C	NEO Energy	Norway	0	100%	0	15.0	0.0	0.0	0.0	0.0	0.0	0.0
Total producing assets								0.0	0.0	0.0	0.0	0.0	0.0
Contingent resources													
Dugong	PL 882	Neptune	Norway	15	100%	14.8	5.9	5.4	2.5	4.0	5.4	6.8	8.2
Total assets under development								5.4	2.5	4.0	5.4	6.8	8.2
Total developments & contingent								5.4	2.5	4.0	5.4	6.8	8.2
Core EV								5.4	2.6	4.0	5.4	6.8	8.2
NPV of Tax								1.5	1.5	1.5	1.5	1.5	1.4
NPV of overhead								-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Cash								0.1	0.1	0.1	0.1	0.1	0.1
Core GAV								6.8	4.0	5.4	6.8	8.2	9.6
Gross Debt								-1.9	-1.9	-1.9	-1.9	-1.9	-1.9
NAV/sh								5.0	2.1	3.6	5.0	6.3	7.7

Source: ABG Sundal Collier, company data

Exploration activities could make a significant impact

Given the small size of Petrolia Noco, relative to the exploration activities it is undertaking, successful exploration could add substantially to the NAV.

The table below shows a risked value of Petrolia Noco's firm exploration activities. Here we simply multiply the mid-point pre-drill resource estimate with the pre-drill chance of success, at various divesture multiples, ranging from USD 1/boe to USD 5/boe. Here we have used Petrolia Noco's resource range for the Dugong Tail prospect, but would again like to highlight the deviation vs. the prospective resources provided by the operator (Neptune), of 33 million boe.

Risked value of exploration activities

Exploration							USD 1/boe	USD 2/boe	USD 3/boe	USD 4/boe	USD 5/boe
Prospect	License	Operator	Timing	Net unrisked, MMboe	CoS	Net risked MMboe	NOK/sh	NOK/sh	NOK/sh	NOK/sh	NOK/sh
Dugong Tail	PL 882	Neptune	Q3'21	23	36%	8	1	1	2	2	3
Molaris	PL 933	Equinor	Q4'21	62	25%	15	1	2	3	4	5
Bounty	PL 935	COP	2022	31	16%	5	0	1	1	1	2
Total exploration				115	25%	29	2	4	5	7	9

Source: ABG Sundal Collier, company data

Another way of addressing the exploration upside potential is to assess the value per well in a successful case. To illustrate this potential the table below shows the value per share at various transaction multiples, assuming the mid-point pre-drill resource estimate is discovered (i.e. the Chance of Success is 100%). As can be seen in the table, such scenarios would constitute a material value for Petrolia Noco relative to the current share price of NOK 3.45/sh.

Unrisked value of exploration activities

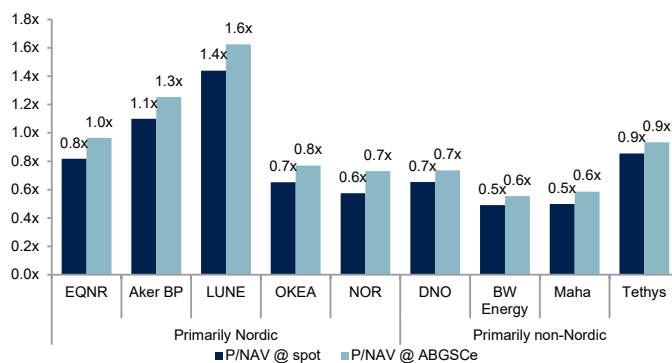
Exploraton							USD 1/boe	USD 2/boe	USD 3/boe	USD 4/boe	USD 5/boe
Prospect	License	Operator	Timing	Net unrisked, MMboe	CoS	Net risked MMboe	NOK/sh	NOK/sh	NOK/sh	NOK/sh	NOK/sh
Dugong Tail	PL 882	Neptune	Q3'21	23	100%	23	1	3	4	6	7
Molaris	PL 933	Equinor	Q4'21	62	100%	62	4	8	11	15	19
Bounty	PL 935	COP	2022	31	100%	31	2	4	6	8	9
Total exploration				115	100%	115	7	14	21	29	36

Source: ABG Sundal Collier, company data

Peer pricing and implied pricing

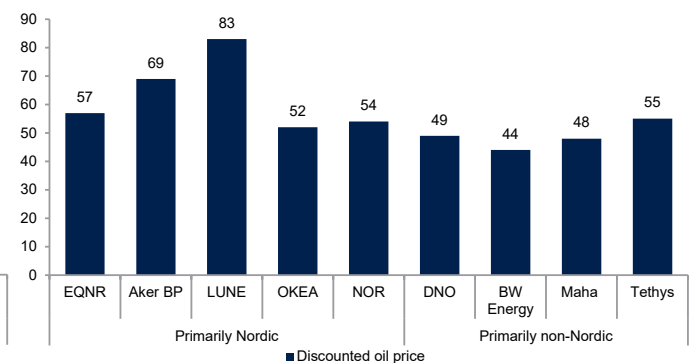
The chart below shows the discounted oil price and P/NAV at ABGSC's oil price assumptions and the spot oil price for the companies under our coverage. Smaller listed E&P companies in the Nordics are currently priced at around 0.5-0.8x NAV (with no value on exploration in the NAV). Limited liquidity, and reduced asset diversification is often used as an explanation for the discounts. Consequently, it would be fair to expect a P/NAV discount for Petrolia Noco also. While exploration could be more impactful for Petrolia Noco than the oil companies shown below, (due to the size of the exploration activities vs. the market cap), we do not anticipate that investors will be willing to materially price the exploration efforts before drilling results come in.

P/NAV (at spot oil price and ABGSCe)



Source: ABG Sundal Collier

Discounted oil price



Source: ABG Sundal Collier

Monetization of discoveries

If Petrolia Noco were to divest its position in Dugong, it is fair to assume that it will not be able to divest it at its full value (leaving some value upside to a potential buyer). Consequently, we look to historical transactions to identify what price can be achieved.

Some relevant transaction data points

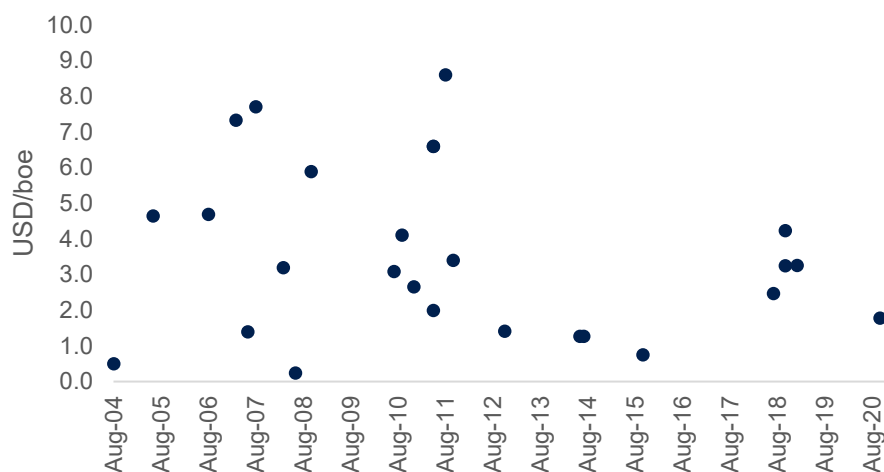
31 July 2018 - Aker BP acquired 11 licenses from Total for USD 205m. The resources in the licenses were net 83 mill boe, which implies a price for the discoveries of ~USD 2.5/boe. This was the first pure discovery acquisition in years.

5 October 2020 - Lundin Energy acquired net 70mill bbl of Barents Sea discoveries (Wisting and Alta) from Idemitsu. The price of USD 125m implies USD 1.8/bbl.

8 October 2020 – Neptune Energy acquired a 5% stake in the Dugong discovery from Concedo. A highly relevant transaction for Petrolia Noco, the Concedo's sale of a 5% stake in the Dugong to the operator Neptune Energy, was announced on 8th October. The purchase price was not disclosed but it was announced that the payment will be partly cash, partly carry of future cost and partly a contingent payment. While without the benefit of knowing the purchase price, our take is that the transaction shows divesture potential in the Dugong asset.

Given that these assets are located far from existing infrastructure, and require substantial work and capex in order to be produced, we view this as a “floor” for what could be expected for Petrolia Noco's resources (being located near existing infrastructure, with the potential for a tie-back solution).

Prices discoveries in the range of USD 1.8-4.2/boe



Source: Company data

**List of some M&A transactions on the NCS over the last few years
(discoveries marked in brown)**

- Neptune acquires a stake in Dugong from Concedo, Oct'20
- LUNE acquires a stake in Wisting and Alta from Idemitsu, Oct'20
- PGNiG acquires a stake in Kvitebjørn and Valemon from Shell, Sep'20
- Okea acquires a stake from Aurora from, Equinor, Jul'20
- PGNiG and Solveig Gas acquire a stake in Duva from Pandion, Nov'19
- Neptune acquires assets from Edison North Sea, Oct'19
- Vår Energy acquires Exxon assets, Sep'19
- ONE-Dyas acquires a stake in Nova from Cairn, Aug'19
- Equinor buys a stake in Johan Sverdrup from Lundin, Jul'19
- PGNiG acquires King Lear from Total, Jun'19
- Mime acquires a stake in Balder, Ringhorne from Vår, Mar'19
- Repsol acquires a stake in Mikkel from Total, Feb'19
- LUPE acquires a stake in Rolvsnes from Lime, Jan'19
- DNO makes an unsolicited offer on FPM, Nov'18
- Kufpec acquires Tommeliten from Equinor, Oct'18
- Aker BP acquires King Lear from Equinor, Oct'18
- LUPE acquires a stake in Luno II from Equinor, Oct'18
- Aker BP acquires licenses from Total, Jul'18
- Eni and Point Resources merge to Vår Energi, Jul'18
- Neptune acquired VNG, Jun'18
- OKEA acquired Draugen and Gjøa from Shell, Jun'18
- DNO acquired a majority stake in Faroe Petroleum, Apr'18
- Repsol acquired a stake in Visund from Total, Feb'18
- Suncor acquired a stake in Fenja from Faroe, Jan'18
- Wintershall and DEA merger, Dec'17
- Pandion acquired a stake in Valhall/Hod from Aker BP, Dec'17
- Aker BP acquired Hess Norge, Oct'17
- Equinor acquired a stake in Martin Linge and Garatiana from Total, Nov'17
- Total acquired Maersk, Aug'17
- Bayerngas and Centrica merger, Jul'17
- Neptune acquired 70% in Engie, May'17
- INEOS acquired DONG, May'17
- Point acquired Exxon's operated business, Apr'17

Source: ABG Sundal Collier

Conclusion:

Our core NAV points to NOK 3.6-6.3/sh with oil prices from USD 50-70/bbl, which is essentially all related to the Dugong discovery. Further to the core NAV we estimate that the risked exploration could make up a further NOK 4-7/sh, assuming a divestible value of USD 2-4/boe. On an un-risked basis, the firm exploration programme could be as much as NOK 14-29/sh assuming a divestible value of USD 2-4/boe.

Taking into account that small E&Ps usually trade at a P/NAV of 0.5-0.8x, we argue for a fair value range of NOK 3-12/sh in the next six months.

Oil market

Positive outlook, but increased shale production is looming

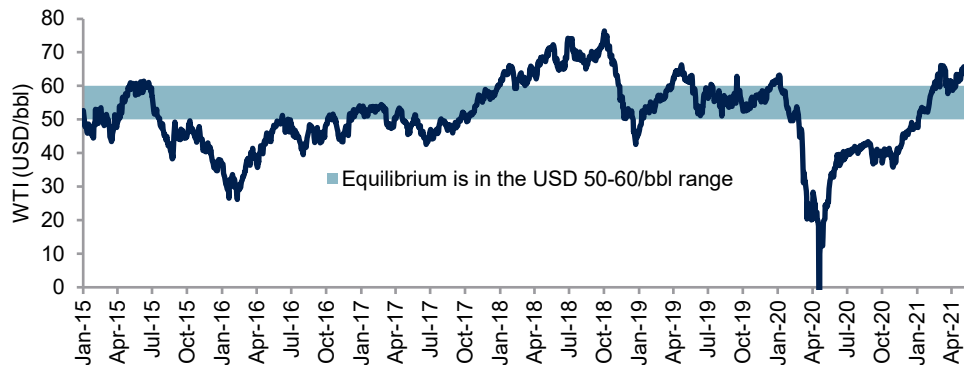
Growing demand and OPEC discipline, but...

...history has shown that WTI at USD 50 is too little and USD 60 is too much

The general outlook for the oil market is positive with increasing demand and a higher call-on-OPEC going forward at the same time as OPEC is showing discipline. On a negative note, we fear that a WTI oil price above USD 60 will trigger a significant increase in US shale production, as it has in the past. Our research indicates that the shale industry needs a WTI of ~USD 50 to keep production flat. When the WTI is higher than USD 60, the growth rate has fairly quickly exceeded 1mb/d, which in turn has led to oversupply in the market. We see some signals that the latter is happening again:

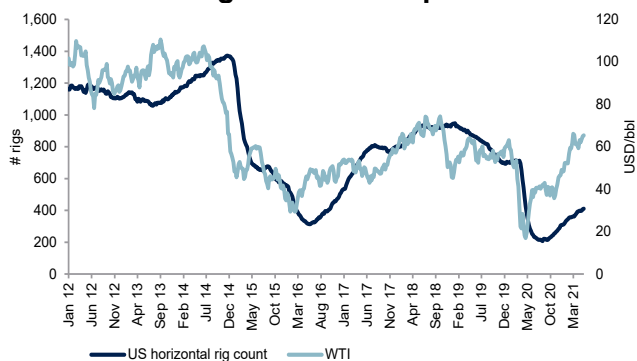
- US horizontal rig count is up ~100% since August
- US shale investments have historically been oil price elastic

WTI: 50 is too little, 60 is too much



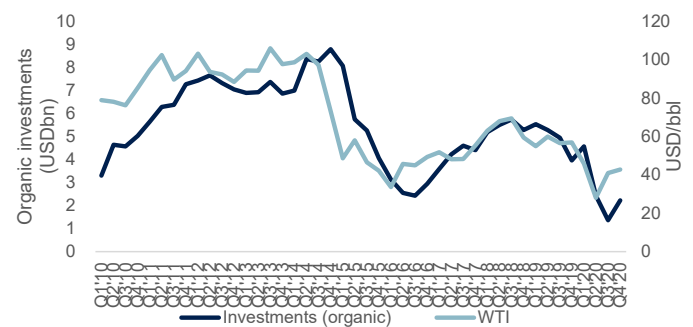
Source: ABG Sundal Collier, company data

US horizontal rig count vs. oil price



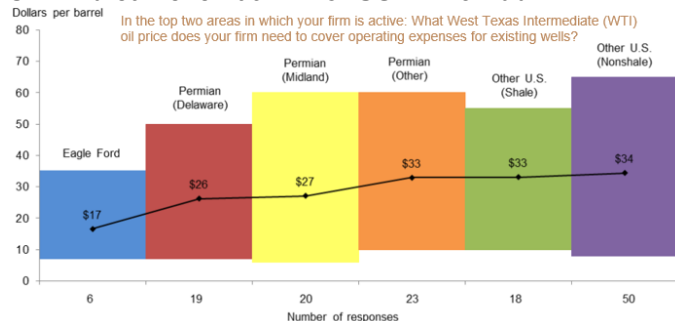
Source: ABG Sundal Collier, Baker Hughes, FactSet

US shale capex vs. oil price



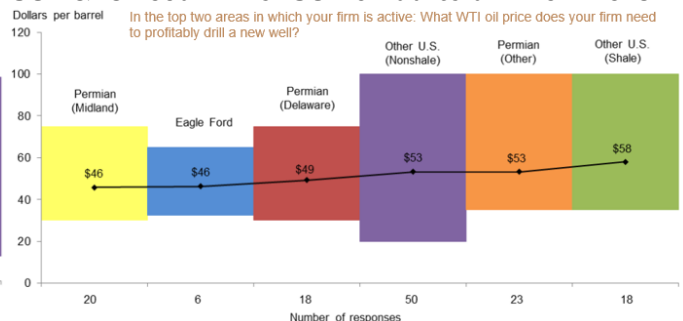
Source: ABG Sundal Collier, company data, FactSet

OPEX break-even at WTI of USD 17-34/bbl



Source: ABG Sundal Collier, FED Dallas

US E&Ps need WTI of USD 52/bbl to drill new wells



Source: ABG Sundal Collier, FED Dallas

We assume Brent of USD 64/bbl in 2021, but still expect Brent to end the year at about USD 60

We estimate Brent long term around USD 60/bbl

Key assumptions	2017	2018	2019	2020	2021e	2022e
Future price (Brent, USD)					65	62
Factset (Brent, USD)					61	64
ABGSC (Brent, USD)	54	71	64	42	65	60
Q1	54	67	63	50	61	60
Q2	50	75	69	29	68	60
Q3	52	75	62	43	65	60
Q4	62	68	63	44	65	60
Other key assumptions:						
WTI (USD)	51	65	57	39	61	56
Brent-WTI spread	3.3	5.9	7.3	2.5	4.2	4.0
Offshore E&P spending:						
Development	-11%	-1%	2%	-17%	-6%	15%
Exploration	-18%	6%	9%	-36%	2%	15%
Total	-12%	0%	3%	-20%	-5%	15%

Source: ABG Sundal Collier, company data

A closer look at consensus for 2021e and 2022e

It is difficult to obtain consensus estimates for supply and demand forecasts in the oil market, so we track the monthly IEA forecasts (OECD's energy agency), OPEC (the oil organisation publishes forecasts in its monthly report), EIA (the US Energy Information Administration) and FGE (Facts Global Energy – an independent consulting firm). The table below shows these agencies' current estimates; we call the average of these agencies' estimates consensus. For 2022, only EIA has detailed estimates provided on a monthly basis.

Oil market estimates

Oil market forecasts 2021e y-o-y change in demand (mb/d), 2021e						
	IEA	OPEC	EIA	FGE	Average/ consensus	ABGSC
Demand:						
North America	1.69	1.81	1.54	1.72	1.69	1.49
Western Europe	0.65	0.60	0.47	0.52	0.56	0.44
OECD Pacific	0.30	0.28	0.35	0.41	0.34	0.39
Total OECD	2.64	2.69	2.36	2.65	2.59	2.31
China	1.06	1.11	0.91	0.37	0.86	0.85
FSU	0.20	0.19	0.20	0.18	0.19	0.16
Middle East	0.18	0.38	0.28	0.46	0.33	0.27
India	0.26	0.48	0.50	0.37	0.40	0.45
"Other non-OECD"	1.09	0.48	1.18	1.36	1.03	1.29
Total non-OECD	2.79	3.26	3.07	2.74	2.97	3.02
Global demand	5.42	5.95	5.42	5.39	5.55	5.33
y-o-y change in production (mb/d), 2021e						
	IEA	OPEC	EIA	FGE	Average/ consensus	ABGSC
Supply:						
US	-0.16	-0.07	-0.08	0.33	0.00	0.23
Canada&Mexico	0.36	0.29	0.29	0.39	0.33	0.53
Western Europe	-0.01	0.04	0.07	0.01	0.03	0.10
OECD Pacific	0.00	0.01	-0.05	n.m.	-0.01	0.02
China	0.09	0.09	0.08	0.06	0.08	-0.03
FSU	0.12	0.02	0.24	0.29	0.17	0.11
Other non-OPEC	0.41	0.20	0.41	0.53	0.39	0.28
Total non-OPEC	0.81	0.58	0.96	1.61	0.99	1.24
Call on OPEC	4.61	5.37	4.46	3.78	4.56	4.08

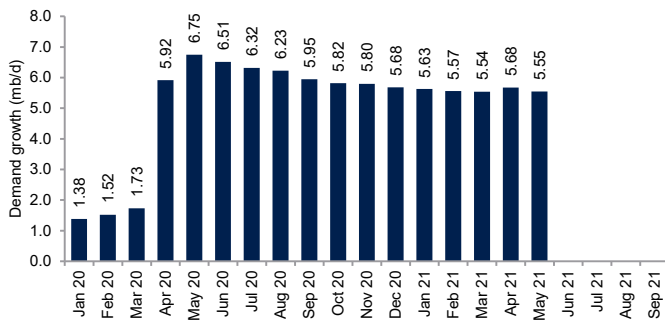
Source: ABG Sundal Collier, OPEC, IEA, FGE, EIA

Oil market forecasts 2022e y-o-y change in demand (mb/d), 2022e		
	EIA	ABGSC
Demand:		
North America	1.09	0.80
Western Europe	0.43	0.26
OECD Pacific	0.09	-0.03
Total OECD	1.61	1.02
China	0.52	0.52
FSU	0.17	0.09
Middle East	0.25	0.08
India	0.34	0.18
"Other non-OECD"	0.84	0.73
Total non-OECD	2.12	1.60
Global demand	3.73	2.62
y-o-y change in production (mb/d), 2022e		
	EIA	ABGSC
Supply:		
US	1.41	0.80
Canada&Mexico	0.03	-0.10
Western Europe	0.10	0.10
OECD Pacific	0.00	0.00
China	0.02	0.00
FSU	0.95	0.70
Other non-OPEC	0.39	0.10
Total non-OPEC	2.90	1.60
Call on OPEC	0.83	1.02

How 2021 estimates have developed over time

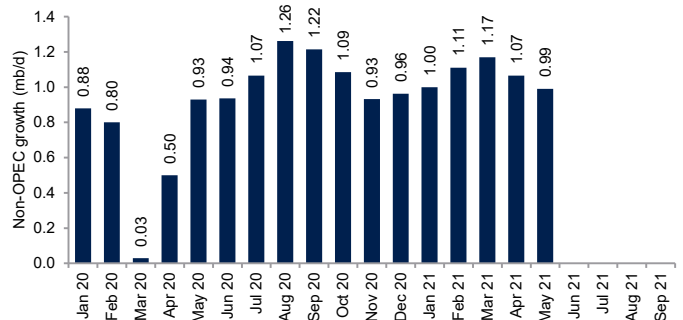
We note that constituents of the 2021 estimates have changed over time as EIA launched detailed estimates in January, FGE in April, IEA in June and OPEC in July.

A demand recovery is expected, but estimates have slipped somewhat lately on re-basing as well as negative vaccine news

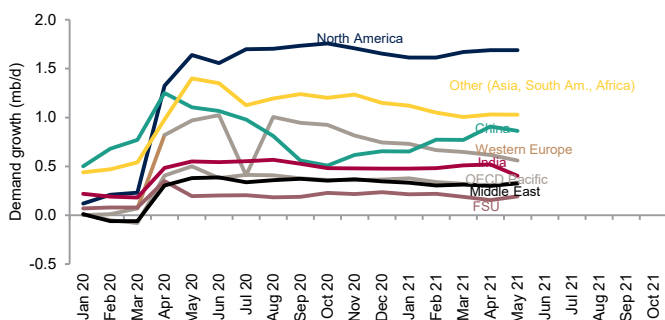


Source: ABG Sundal Collier, OPEC, IEA, FGE, EIA

Non-OPEC supply estimates trend around 1mb/d growth

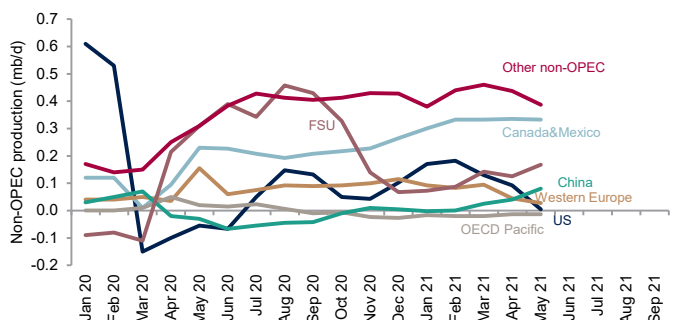


Demand: Broad recovery anticipated, on Covid-19 restriction easing

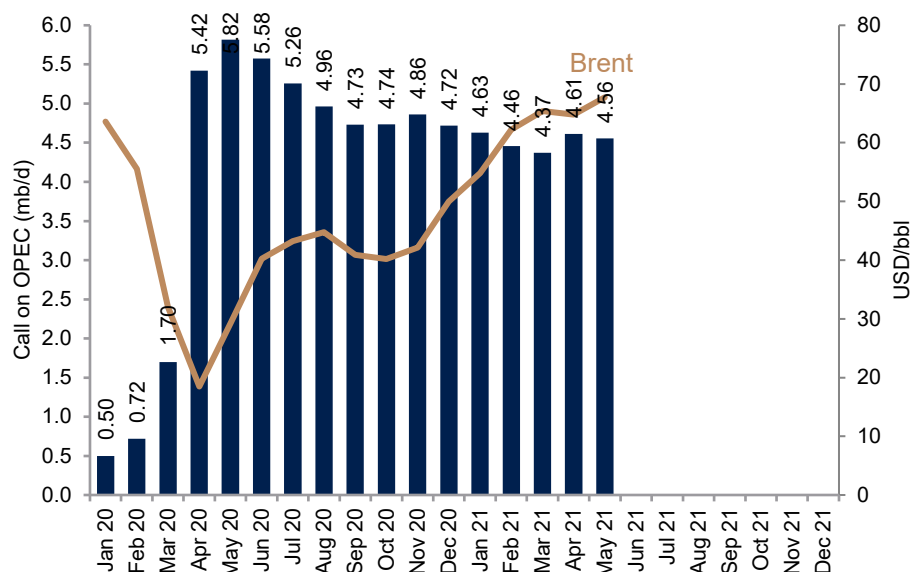


Source: ABG Sundal Collier, OPEC, IEA, FGE, EIA

Non-Opec supply: Other non-OPEC and Canada expected to drive y-o-y growth in 2021, US estimates are slipping



Consensus call-on-OPEC



Source: ABG Sundal Collier, OPEC, IEA, FGE, EIA

Key oil market estimates

Oil market estimates – annual figures (million barrels/day)

Oil demand (mb/d)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
OECD												
US	18.8	19.3	19.4	19.8	20.0	20.0	20.5	20.5	18.1	19.2	20.0	20.1
Other America (Canada, Mexico, Chile)	4.9	4.9	4.8	4.8	4.9	5.1	5.0	5.1	4.4	4.8	4.8	4.9
Europe	13.8	13.6	13.5	13.8	14.0	14.4	14.3	14.2	12.4	12.9	13.1	13.1
Asia Oceania	8.5	8.3	8.1	8.1	8.1	8.2	8.1	7.8	7.1	7.5	7.4	7.4
Total OECD	46.0	46.1	45.8	46.5	47.0	47.6	47.9	47.7	42.1	44.4	45.4	45.5
y-o-y (%)	-1.1 %	0.2 %	-0.6 %	1.6 %	1.0 %	1.3 %	0.5 %	-0.4 %	-11.8 %	5.5 %	2.3 %	0.2 %
Non-OECD												
FSU	4.6	4.7	5.1	5.1	5.0	4.5	4.6	4.8	4.6	4.7	4.8	4.9
Europe	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.7	0.8	0.8	0.8
China	9.8	10.4	10.8	11.6	12.0	12.5	13.0	13.7	13.9	14.8	15.3	15.7
India	3.6	3.7	3.8	4.2	4.4	4.7	4.9	5.0	4.5	5.0	5.2	5.3
Other Asia	7.8	8.1	8.1	7.5	8.0	9.3	9.2	9.0	8.1	8.7	8.9	9.0
Latin-America	6.5	6.6	6.8	6.7	6.5	6.3	6.3	6.2	5.6	5.9	6.2	6.4
Middle East	7.8	8.1	8.4	8.5	8.4	8.4	8.3	8.3	7.6	7.9	8.0	8.0
Africa	3.7	4.0	4.1	4.2	4.2	4.3	4.2	4.3	3.9	4.2	4.5	4.8
Total Non-OECD	44.6	46.3	47.9	48.5	49.2	50.7	51.3	52.0	48.9	51.9	53.5	55.0
y-o-y (%)	3.9 %	3.8 %	3.4 %	1.3 %	1.5 %	2.9 %	1.3 %	1.4 %	-5.9 %	6.2 %	3.1 %	2.7 %
TOTAL DEMAND	90.5	92.3	93.7	95.0	96.2	98.3	99.2	99.7	91.0	96.3	99.0	100.5
y-o-y (%)	1.3 %	2.0 %	1.4 %	1.5 %	1.2 %	2.2 %	0.9 %	0.6 %	-8.7 %	5.9 %	2.7 %	1.6 %
Oil supply (mb/d)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
NON-OPEC												
US	9.1	10.3	12.0	13.0	12.5	13.2	15.5	17.2	16.6	16.8	17.6	18.3
Mexico	2.9	2.9	2.8	2.6	2.5	2.2	2.1	1.9	1.9	2.1	2.0	2.0
Canada	3.7	4.0	4.3	4.4	4.5	4.8	5.4	5.5	5.3	5.7	5.7	5.7
North America	15.8	17.2	19.1	20.0	19.5	20.3	23.0	24.7	23.8	24.6	25.3	26.0
Europe	3.5	3.3	3.3	3.5	3.5	3.5	3.5	3.3	3.5	3.6	3.7	3.7
Pacific	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.6
Total OECD	19.8	21.0	22.9	23.9	23.4	24.2	26.9	28.5	27.9	28.8	29.6	30.3
FSU	13.6	13.8	13.9	14.0	14.2	14.3	14.6	14.6	13.5	13.6	14.3	14.3
China	4.1	4.2	4.2	4.3	4.0	3.9	3.8	3.9	4.0	3.9	3.9	3.9
Brazil	2.2	2.1	2.4	2.5	2.6	2.7	2.7	2.9	3.0	3.2	3.2	3.3
Other non-OECD	12.5	12.7	12.8	12.8	12.6	12.4	12.7	13.3	12.5	12.6	12.7	12.5
Processing Gains	2.1	2.2	2.2	2.2	2.3	2.3	2.3	2.4	2.1	2.2	2.2	2.2
Total Non-OPEC	54.3	56.0	58.3	59.8	59.1	59.8	62.9	65.6	63.1	64.3	65.9	66.5
y-o-y (%)	1.4 %	3.1 %	4.2 %	2.4 %	-1.1 %	1.2 %	5.2 %	4.2 %	-3.8 %	2.0 %	2.5 %	0.9 %
OPEC												
Saudi Arabia	9.5	9.4	9.5	10.1	10.4	10.0	10.3	9.8	9.2	9.0	9.3	9.3
UAE	2.7	2.8	2.8	3.0	3.1	2.9	3.0	3.2	2.9	2.7	2.9	2.9
Venezuela	2.5	2.5	2.5	2.5	2.2	2.0	1.4	0.9	0.5	0.5	0.6	0.6
Kuwait	2.5	2.6	2.6	2.8	2.9	2.7	2.8	2.7	2.4	2.6	2.8	2.8
Angola	1.8	1.7	1.7	1.8	1.7	1.6	1.5	1.4	1.3	1.3	1.3	1.3
Nigeria	2.0	1.8	1.9	1.8	1.5	1.5	1.6	1.7	1.5	1.6	1.6	1.6
Libya	1.4	0.9	0.5	0.4	0.4	0.8	1.0	1.1	0.4	0.5	0.8	0.8
Algeria	1.2	1.2	1.1	1.1	1.1	1.1	1.0	1.0	0.9	0.9	0.9	0.9
Ecuador	0.5	0.5	0.6	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5
OPEC 9	24.0	23.3	23.0	23.9	23.8	23.2	23.1	22.3	19.5	19.7	20.8	20.8
Iraq	3.0	3.1	3.3	4.0	4.4	4.5	4.6	4.7	4.1	3.9	4.1	4.3
Iran	3.0	2.7	2.8	2.9	3.6	3.8	3.0	2.4	2.0	2.0	2.4	2.6
OPEC 11	29.9	29.1	29.2	30.7	31.8	31.4	30.7	29.4	25.6	25.6	27.3	27.6
Gabon	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Other OPEC	1.1	1.0	0.8	0.5	0.3	0.4	1.0	0.3	0.0	0.0	0.0	0.0
Total OPEC crude	31.3	30.3	30.2	31.4	32.4	32.0	31.9	29.9	25.8	25.7	27.4	27.8
NGLs	5.1	5.0	5.1	5.3	5.5	5.6	5.5	5.5	5.2	5.3	5.3	5.3
Total OPEC	36.3	35.3	35.3	36.7	37.9	37.6	37.4	35.4	31.0	31.0	32.7	33.1
TOTAL SUPPLY	90.6	91.3	93.7	96.5	96.9	97.4	100.3	101.0	94.1	95.4	98.7	99.6
Key figures												
Call on OPEC crude	31.2	31.4	30.2	30.0	31.6	32.8	30.7	28.6	22.7	26.7	27.7	28.7
OPEC crude production	31.3	30.3	30.2	31.4	32.4	32.0	31.9	29.9	25.8	25.7	27.4	27.8
= Implied stock change	0.0	-1.1	0.0	1.5	0.7	-0.9	1.2	1.3	3.1	-1.0	-0.3	-0.9
Change in OECD Industry Stocks (mb/d)	0.2	-0.2	0.3	0.8	0.0	-0.4	0.0	0.0	0.4	-0.5	-0.2	-0.5
Implicit change in other stocks (mb/d)	-0.1	-1.0	-0.3	0.7	0.7	-0.4	1.2	1.3	2.6	-0.5	-0.2	-0.5
OECD Industry Stocks (mill. barrels)	2,664	2,589	2,706	2,989	3,007	2,860	2,875	2,889	3,037	2,858	2,803	2,636
OECD Inventory Days (industry)	57.9	56.5	58.2	63.6	63.2	59.8	60.3	68.7	68.4	62.9	61.6	58.0

Source: ABG Sundal Collier, IEA

Oil market estimates – annual figures (y-o-y growth, million barrels/d)

y-o-y growth													
Growth y-o-y (mb/d)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e	
OECD													
US	-0.5	0.5	0.1	0.4	0.2	0.0	0.5	0.0	-2.4	1.1	0.8	0.1	
Other America (Canada, Mexico, Chile)	0.0	0.0	-0.1	0.0	0.1	0.2	-0.1	0.1	-0.7	0.4	0.0	0.0	
Europe	-0.5	-0.2	-0.1	0.3	0.2	0.4	-0.1	0.0	-1.8	0.4	0.3	0.0	
Asia Oceania	0.4	-0.2	-0.2	0.0	0.0	0.0	-0.1	-0.3	-0.7	0.4	0.0	0.0	
Total OECD	-0.5	0.1	-0.3	0.7	0.4	0.6	0.3	-0.2	-5.6	2.3	1.0	0.1	
y-o-y (%)	-1.1 %	0.2 %	-0.6 %	1.6 %	1.0 %	1.3 %	0.5 %	-0.4 %	-11.8 %	5.5 %	2.3 %	0.2 %	
Non-OECD													
FSU	0.0	0.1	0.4	0.0	-0.1	-0.5	0.1	0.2	-0.2	0.2	0.1	0.1	
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	
China	0.4	0.6	0.4	0.8	0.4	0.5	0.5	0.7	0.3	0.8	0.5	0.4	
India	0.2	0.0	0.2	0.4	0.2	0.2	0.2	0.1	-0.5	0.4	0.2	0.2	
Other Asia	0.3	0.3	0.1	-0.6	0.4	1.3	-0.1	-0.2	-0.9	0.6	0.1	0.2	
Latin America	0.3	0.1	0.2	-0.1	-0.2	-0.1	0.0	-0.1	-0.6	0.3	0.2	0.2	
Middle East	0.4	0.3	0.3	0.1	-0.1	-0.1	0.0	0.0	-0.7	0.3	0.1	0.0	
Africa	0.2	0.3	0.1	0.0	0.1	0.0	0.0	0.0	-0.4	0.3	0.3	0.4	
Total Non-OECD	1.7	1.7	1.6	0.6	0.7	1.4	0.6	0.7	-3.1	3.0	1.6	1.5	
y-o-y (%)	3.9 %	3.8 %	3.4 %	1.3 %	1.5 %	2.9 %	1.3 %	1.4 %	-5.9 %	6.2 %	3.1 %	2.7 %	
TOTAL DEMAND													
	1.2	1.8	1.3	1.4	1.2	2.1	0.9	0.6	-8.7	5.3	2.6	1.6	
y-o-y (%)	1.3 %	2.0 %	1.4 %	1.5 %	1.2 %	2.2 %	0.9 %	0.6 %	-8.7 %	5.9 %	2.7 %	1.6 %	
y-o-y growth													
Oil supply (mb/d)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e	
NON-OPEC													
US	1.0	1.2	1.7	1.0	-0.5	0.7	2.3	1.7	-0.6	0.2	0.8	0.7	
Mexico	0.0	0.0	-0.1	-0.2	-0.1	-0.2	-0.2	-0.1	0.0	0.1	-0.1	0.0	
Canada	0.2	0.3	0.3	0.1	0.1	0.4	0.6	0.1	-0.2	0.4	0.0	0.0	
North America	1.2	1.4	1.9	0.9	-0.5	0.8	2.7	1.7	-0.8	0.8	0.7	0.7	
Europe	-0.3	-0.1	0.0	0.2	0.0	0.0	0.0	-0.1	0.2	0.1	0.1	0.0	
Pacific	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	
Total OECD	0.9	1.2	1.9	1.0	-0.5	0.8	2.7	1.6	-0.6	0.9	0.8	0.7	
FSU	0.0	0.2	0.1	0.1	0.2	0.1	0.2	0.1	-1.1	0.1	0.7	0.0	
China	0.1	0.0	0.0	0.1	-0.3	-0.1	-0.1	0.1	0.1	0.0	0.0	0.0	
Brazil	0.0	0.0	0.2	0.2	0.1	0.1	0.0	0.2	0.2	0.2	0.0	0.1	
Other non-OECD	-0.3	0.2	0.1	-0.1	-0.2	-0.2	0.3	0.6	-0.7	0.0	0.1	-0.2	
Processing Gains	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	0.1	0.0	0.0	
Total Non-OPEC	0.7	1.7	2.4	1.4	-0.7	0.7	3.1	2.6	-2.5	1.2	1.6	0.6	
y-o-y (%)	1.4 %	3.1 %	4.2 %	2.4 %	-1.1 %	1.2 %	5.2 %	4.2 %	-3.8 %	2.0 %	2.5 %	0.9 %	
OPEC													
Saudi Arabia	0.4	-0.1	0.1	0.6	0.3	-0.5	0.4	-0.5	-0.6	-0.2	0.3	0.0	
UAE	0.2	0.1	0.0	0.2	0.1	-0.1	0.1	0.2	-0.3	-0.2	0.2	0.0	
Venezuela	0.0	0.0	0.0	0.0	-0.2	-0.3	-0.6	-0.5	-0.3	0.0	0.1	0.0	
Kuwait	0.2	0.1	0.1	0.2	0.1	-0.2	0.0	-0.1	-0.3	0.2	0.2	0.0	
Angola	0.1	-0.1	-0.1	0.1	-0.1	-0.1	-0.2	-0.1	-0.1	0.0	0.0	0.0	
Nigeria	0.0	-0.2	0.0	-0.1	-0.3	0.1	0.1	0.1	-0.2	0.1	0.0	0.0	
Libya	0.9	-0.5	-0.4	-0.1	0.0	0.4	0.1	0.1	-0.7	0.1	0.3	0.0	
Algeria	0.0	0.0	0.0	0.0	0.0	-0.1	0.0	0.0	-0.1	0.0	0.0	0.0	
Ecuador	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	
OPEC 9	1.8	-0.6	-0.3	0.9	0.0	-0.7	-0.1	-0.8	-2.8	0.1	1.1	0.0	
Iraq	0.3	0.1	0.3	0.7	0.4	0.0	0.1	0.1	-0.7	-0.1	0.2	0.2	
Iran	-0.6	-0.3	0.1	0.0	0.7	0.3	-0.8	-0.6	-0.4	0.0	0.4	0.2	
OPEC 11	1.5	-0.8	0.0	1.6	1.1	-0.4	-0.8	-1.3	-3.8	0.0	1.7	0.4	
Gabon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Other OPEC	0.0	-0.1	-0.1	-0.4	-0.1	0.0	0.7	-0.7	-0.3	0.0	0.0	0.0	
Total OPEC crude	1.1	-1.1	0.3	1.9	2.1	0.0	-0.8	-2.5	-5.2	-0.1	2.3	0.7	
NGLs	0.3	-0.1	0.1	0.2	0.2	0.1	-0.1	0.0	-0.3	0.1	0.0	0.0	
Total OPEC	1.7	-1.0	0.1	1.4	1.1	-0.3	-0.2	-2.0	-4.4	0.0	1.7	0.4	
TOTAL SUPPLY													
	2.5	0.7	2.4	2.8	0.5	0.5	2.9	0.7	-6.9	1.3	3.3	0.9	
Key figures													
Call on OPEC crude	0.2	0.2	-1.2	-0.2	1.6	1.2	-2.1	-2.1	-5.9	4.0	1.0	1.0	
OPEC crude production	1.5	-0.9	-0.1	1.2	0.9	-0.4	-0.1	-2.0	-4.1	0.0	1.7	0.4	

Source: ABG Sundal Collier, IEA

Oil market estimates – quarterly figures (million barrels/day)

Oil demand (mill. b/d)	Q1'19	Q2'19	Q3'19	Q4'19	Q1'20	Q2'20	Q3'20	Q4'20	Q1'21e	Q2'21e	Q3'21e	Q4'21e
OECD												
US	20.4	20.5	20.7	20.6	19.3	16.1	18.4	18.7	18.4	18.9	19.6	20.0
Other America (Canada, Mexico, Chile)	4.9	5.0	5.3	5.2	5.0	3.9	4.4	4.4	4.6	4.7	4.9	5.0
Europe	14.0	14.2	14.7	14.1	13.3	11.0	12.9	12.6	11.9	12.9	13.4	13.4
Pacific	8.2	7.4	7.6	8.0	7.8	6.5	6.7	7.3	7.7	7.1	7.2	7.8
Total OECD	47.5	47.1	48.3	47.9	45.4	37.6	42.3	43.1	42.7	43.6	45.1	46.2
y-o-y (%)	-1.1 %	-0.5 %	-0.1 %	0.2 %	-4.4 %	-20.2 %	-12.4 %	-10.1 %	-6.1 %	16.0 %	6.8 %	7.3 %
Non-OECD												
FSU	4.6	4.7	5.0	4.9	4.6	4.0	4.8	4.8	4.6	4.5	4.9	4.9
Europe	0.7	0.8	0.8	0.8	0.7	0.6	0.8	0.8	0.7	0.7	0.8	0.8
China	13.1	13.6	13.9	14.1	11.8	14.2	14.7	14.9	14.3	14.8	14.9	15.1
India	5.1	5.1	4.8	5.0	4.9	3.9	4.3	5.0	5.1	5.1	4.7	5.1
Other Asia	9.2	9.1	8.8	9.0	8.5	7.3	8.1	8.5	8.6	8.7	8.7	8.9
Latin America	6.1	6.2	6.3	6.3	5.8	4.9	5.8	5.9	5.8	5.8	6.1	6.0
Middle East	8.1	8.1	8.7	8.3	7.8	7.0	8.1	7.7	7.6	7.8	8.4	7.9
Africa	4.3	4.3	4.2	4.3	4.2	3.3	3.9	4.0	4.2	4.1	4.1	4.3
Total Non-OECD	51.2	51.8	52.3	52.7	48.3	45.3	50.4	51.7	50.9	51.4	52.6	53.0
y-o-y (%)	1.2 %	0.7 %	1.5 %	2.3 %	-5.6 %	-12.6 %	-3.7 %	-2.0 %	5.3 %	13.4 %	4.3 %	2.5 %
TOTAL DEMAND	98.7	98.9	100.6	100.6	93.8	82.9	92.7	94.7	93.6	95.0	97.7	99.2
y-o-y (%)	0.1 %	0.2 %	0.7 %	1.3 %	-5.0 %	-16.2 %	-7.9 %	-5.8 %	-0.2 %	14.6 %	5.4 %	4.7 %
Oil supply (mill. b/d)	Q1'19	Q2'19	Q3'19	Q4'19	Q1'20	Q2'20	Q3'20	Q4'20	Q1'21e	Q2'21e	Q3'21e	Q4'21e
NON-OPEC												
US	16.6	17.1	17.2	17.9	18.0	16.0	16.3	16.2	15.9	17.0	17.2	17.2
Mexico	1.9	1.9	1.9	2.0	2.0	1.9	1.9	1.9	2.0	2.0	2.1	2.1
Canada	5.4	5.5	5.5	5.7	5.7	5.0	5.0	5.6	5.8	5.5	5.7	5.9
North America	24.0	24.5	24.7	25.6	25.7	22.8	23.1	23.7	23.7	24.6	25.0	25.2
Europe	3.5	3.2	3.2	3.5	3.7	3.6	3.4	3.5	3.6	3.6	3.6	3.8
Pacific	0.4	0.5	0.5	0.6	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6
Total OECD	27.9	28.2	28.4	29.6	30.0	26.9	27.1	27.7	27.8	28.7	29.2	29.5
14.8	14.4	14.6	14.7	14.8	13.2	12.8	13.2	13.4	13.6	13.7	13.7	13.7
China	3.9	4.0	3.9	3.9	4.0	4.0	4.0	3.9	4.0	4.0	3.9	3.9
Brazil	2.7	2.7	3.0	3.2	3.2	3.0	3.1	2.9	3.0	3.3	3.3	3.3
Other	12.9	13.5	13.6	13.1	12.5	12.2	12.9	12.6	12.3	12.8	13.1	12.1
Processing Gains	2.3	2.4	2.4	2.3	2.3	2.0	2.1	2.1	2.1	2.2	2.3	2.3
Total Non-OPEC	64.5	65.1	65.9	66.8	66.7	61.3	61.9	62.5	62.6	64.5	65.4	64.8
y-o-y (%)	5.6 %	5.0 %	3.9 %	4.1 %	3.3 %	-5.8 %	-6.0 %	-6.5 %	-6.1 %	5.3 %	5.7 %	3.6 %
OPEC												
Saudi Arabia	10.1	9.8	9.5	9.9	9.8	9.3	8.8	9.0	8.5	8.7	8.9	10.0
UAE	3.1	3.1	3.2	3.3	3.3	2.9	2.8	2.5	2.6	2.7	2.7	2.7
Venezuela	1.1	0.9	0.8	0.8	0.8	0.5	0.4	0.4	0.4	0.4	0.6	0.6
Kuwait	2.7	2.7	2.7	2.7	2.7	2.5	2.3	2.3	2.5	2.6	2.7	2.7
Angola	1.4	1.4	1.4	1.4	1.4	1.3	1.2	1.2	1.3	1.3	1.3	1.3
Nigeria	1.7	1.7	1.8	1.7	1.7	1.6	1.4	1.3	1.5	1.6	1.6	1.6
Libya	1.0	1.2	1.1	1.2	0.3	0.1	0.1	0.9	0.4	0.4	0.6	0.6
Algeria	1.0	1.0	1.0	1.0	1.0	0.9	0.8	0.9	0.9	0.9	0.9	0.9
Ecuador	0.5	0.5	0.6	0.5	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.5
OPEC 9	22.6	22.2	21.9	22.5	21.5	19.3	18.4	19.0	18.6	19.2	19.9	21.0
Iraq	4.7	4.7	4.8	4.6	4.6	4.1	3.7	3.8	3.7	3.9	4.1	4.1
Iran	2.7	2.4	2.2	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
OPEC 11	30.0	29.4	28.9	29.2	28.1	25.4	24.0	24.8	24.2	25.1	26.0	27.1
Gabon	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Other OPEC	0.4	0.5	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total OPEC crude	30.7	30.1	29.5	29.4	28.3	25.6	24.2	25.0	24.4	25.2	26.1	27.2
NGLs	5.6	5.5	5.5	5.4	5.4	5.2	5.1	5.2	5.2	5.3	5.3	5.3
Total OPEC	36.2	35.6	35.0	34.8	33.8	30.7	29.3	30.2	29.6	30.5	31.4	32.6
TOTAL SUPPLY	100.7	100.7	100.8	101.6	100.4	92.1	91.2	92.6	92.2	95.0	96.9	97.3
Key figures	Q1'19	Q2'19	Q3'19	Q4'19	Q1'20	Q2'20	Q3'20	Q4'20	Q1'21e	Q2'21e	Q3'21e	Q4'21e
Call on OPEC crude	28.6	28.3	29.2	28.4	21.7	16.4	25.7	27.1	25.7	25.1	27.0	29.1
OPEC crude production	30.7	30.1	29.5	29.4	28.3	25.6	24.2	25.0	24.4	25.2	26.1	27.2
= Implied stock change	2.0	1.8	0.3	1.0	6.6	9.2	-1.5	-2.1	-1.4	0.1	-0.8	-1.8
Change in OECD Industry Stocks (mb/d)	1.0	0.9	0.1	0.5	3.3	4.6	-0.7	-1.0	-0.7	0.0	-0.4	-0.9
Implicit change in other stocks (mb/d)	2.0	1.2	0.2	1.7	5.7	6.3	-1.0	-0.4	-0.7	0.0	-0.4	-0.9
OECD Industry Stocks (mill. barrels)	2,875	2,932	2,942	2,889	2,974	3,212	3,176	3,037	2,976	2,980	2,942	2,858
OECD Inventory Days (industry)	61.0	65.5	68.0	60.6	70.7	76.3	75.5	72.2	67.0	67.1	66.3	64.4

Source: ABG Sundal Collier, IEA

Oil market estimates – quarterly figures (y-o-y growth, million barrels/d)

Growth y-o-y (mill. barrels/day)	Q1'19	Q2'19	Q3'19	Q4'19	Q1'20	Q2'20	Q3'20	Q4'20	Q1'21e	Q2'21e	Q3'21e	Q4'21e
OECD												
US	0.0	0.1	0.0	0.0	-1.0	-4.4	-2.4	-1.9	-0.9	2.8	1.3	1.3
Other America (Canada, Mexico, Chile)	0.0	0.0	0.2	0.2	0.1	-1.1	-0.9	-0.8	-0.4	0.8	0.6	0.6
Europe	-0.1	0.0	0.0	0.0	-0.7	-3.2	-1.8	-1.5	-1.4	1.9	0.5	0.8
Pacific	-0.4	-0.3	-0.2	-0.1	-0.5	-0.9	-0.9	-0.7	0.0	0.6	0.5	0.5
Total OECD	-0.5	-0.2	0.0	0.1	-2.1	-9.5	-6.0	-4.9	-2.8	6.0	2.9	3.1
y-o-y (%)	-1.1 %	-0.5 %	-0.1 %	0.2 %	-4.4 %	-20.2 %	-12.4 %	-10.1 %	-6.1 %	16.0 %	6.8 %	7.3 %
Non-OECD												
FSU	0.2	0.2	0.2	0.2	0.1	-0.7	-0.2	-0.1	-0.1	0.5	0.1	0.1
Europe	0.0	0.0	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.1	0.0	0.0
China	0.4	0.7	0.7	1.0	-1.3	0.6	0.9	0.8	2.5	0.5	0.2	0.2
India	0.2	0.0	0.1	0.2	-0.2	-1.2	-0.5	0.0	0.2	1.2	0.4	0.1
Other Asia	-0.1	-0.3	-0.3	-0.3	-0.6	-1.7	-0.7	-0.5	0.1	1.3	0.6	0.5
Latin America	-0.1	0.0	-0.1	-0.1	-0.4	-1.3	-0.5	-0.3	0.0	0.9	0.3	0.1
Middle East	0.0	-0.3	0.1	0.2	-0.3	-1.2	-0.6	-0.6	-0.1	0.8	0.3	0.1
Africa	0.0	0.0	0.0	0.0	-0.1	-1.0	-0.3	-0.3	0.0	0.7	0.3	0.3
Total Non-OECD	0.6	0.4	0.7	1.2	-2.9	-6.5	-1.9	-1.0	2.6	6.1	2.2	1.3
y-o-y (%)	1.2 %	0.7 %	1.5 %	2.3 %	-5.6 %	-12.6 %	-3.7 %	-2.0 %	5.3 %	13.4 %	4.3 %	2.5 %
TOTAL DEMAND	0.1	0.2	0.7	1.3	-4.9	-16.0	-7.9	-5.9	-0.2	12.1	5.0	4.4
y-o-y (%)	0.1 %	0.2 %	0.7 %	1.3 %	-5.0 %	-16.2 %	-7.9 %	-5.8 %	-0.2 %	14.6 %	5.4 %	4.7 %
Oil supply (mill. b/d)												
NON-OPEC												
US	2.3	2.0	1.2	1.4	1.4	-1.1	-0.9	-1.7	-2.2	1.1	1.0	1.0
Mexico	-0.2	-0.2	-0.1	0.0	0.1	0.0	0.0	-0.1	0.0	0.1	0.2	0.2
Canada	0.3	0.5	0.3	0.2	0.3	-0.5	-0.6	-0.1	0.1	0.5	0.7	0.3
North America	2.3	2.4	1.4	1.6	1.7	-1.7	-1.5	-1.9	-2.1	1.7	1.9	1.5
Europe	-0.1	-0.2	-0.1	0.0	0.2	0.4	0.2	0.0	0.0	0.0	0.2	0.2
Pacific	0.0	0.1	0.1	0.1	0.1	0.1	0.0	-0.1	0.0	0.0	0.0	0.0
Total OECD	2.2	2.3	1.3	1.7	2.1	-1.2	-1.3	-1.9	-2.1	1.7	2.1	1.8
FSU	0.4	0.0	0.0	-0.1	0.0	-1.2	-1.8	-1.5	-1.4	0.4	0.9	0.5
China	0.1	0.1	0.1	0.0	0.1	0.0	0.1	0.1	0.0	0.0	0.0	-0.1
Brazil	0.0	0.0	0.4	0.4	0.5	0.3	0.1	-0.3	-0.1	0.3	0.1	0.4
Other	0.7	0.7	0.6	0.6	-0.3	-1.3	-0.8	-0.5	-0.3	0.6	0.2	-0.5
Processing Gains	0.0	0.0	0.1	0.0	-0.1	-0.4	-0.3	-0.2	-0.1	0.2	0.2	0.2
Total Non-OPEC	3.4	3.1	2.5	2.6	2.2	-3.8	-4.0	-4.3	-4.0	3.2	3.5	2.3
y-o-y (%)	5.6 %	5.0 %	3.9 %	4.1 %	3.3 %	-5.8 %	-6.0 %	-6.5 %	-6.1 %	5.3 %	5.7 %	3.6 %
OPEC												
Saudi Arabia	0.1	-0.4	-0.9	-0.9	-0.3	-0.4	-0.7	-0.9	-1.3	-0.7	0.1	1.0
UAE	0.2	0.2	0.2	0.1	0.2	-0.2	-0.3	-0.8	-0.6	-0.1	-0.1	0.2
Venezuela	-0.4	-0.5	-0.6	-0.5	-0.3	-0.3	-0.4	-0.4	-0.4	-0.1	0.2	0.2
Kuwait	0.0	0.0	-0.1	-0.1	0.0	-0.2	-0.4	-0.4	-0.2	0.2	0.5	0.4
Angola	0.4	-0.1	-0.1	-0.1	0.0	-0.2	-0.1	-0.2	-0.1	0.1	0.1	0.1
Nigeria	0.0	0.2	0.2	0.1	0.0	-0.2	-0.4	-0.4	-0.2	0.0	0.2	0.3
Libya	-0.1	0.3	0.0	0.1	-0.6	-1.1	-1.0	-0.3	0.1	0.3	0.5	-0.3
Algeria	0.0	0.0	0.0	-0.1	0.0	-0.2	-0.2	-0.2	-0.1	0.0	0.1	0.1
Ecuador	0.0	0.0	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.2	0.0	0.0
OPEC 9	0.3	-0.3	-1.4	-1.4	-1.1	-3.0	-3.5	-3.5	-3.0	-0.1	1.6	2.0
Iraq	0.3	0.3	0.1	0.0	-0.1	-0.6	-1.1	-0.8	-0.9	-0.2	0.4	0.3
Iran	-1.1	-1.4	-1.4	-0.9	-0.7	-0.5	-0.2	-0.1	0.0	0.0	0.0	0.0
OPEC 11	-0.5	-1.5	-2.7	-2.4	-1.9	-4.0	-4.9	-4.4	-3.9	-0.3	2.0	2.3
Gabon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0	0.0
Other OPEC	-0.6	0.0	0.2	-0.4	-0.4	-0.5	-0.4	0.0	0.0	0.0	0.0	0.0
Total OPEC crude	-1.1	-1.5	-2.5	-2.8	-2.3	-4.5	-5.3	-4.4	-3.9	-0.4	2.0	2.3
NGLs	0.0	0.0	-0.1	-0.2	-0.2	-0.4	-0.4	-0.2	-0.2	0.1	0.2	0.1
Total OPEC	-1.0	-1.5	-2.6	-3.0	-2.5	-4.8	-5.7	-4.6	-4.2	-0.2	2.2	2.4
TOTAL SUPPLY	2.4	1.6	-0.2	-0.3	-0.3	-8.6	-9.7	-9.0	-8.2	3.0	5.7	4.7
Key figures												
Call on OPEC crude	-3.4	-2.9	-1.7	-1.2	-6.9	-11.9	-3.6	-1.3	4.0	8.7	1.3	2.0
OPEC crude production	-1.1	-1.5	-2.5	-2.8	-2.3	-4.5	-5.3	-4.4	-3.9	-0.4	2.0	2.3

Source: ABG Sundal Collier, IEA

Fiscal terms

The ordinary tax regime for petroleum activities offshore Norway is illustrated below.

Marginal tax rate: The marginal tax rate for petroleum activities offshore Norway is 78%, comprising of 22% corporate tax (CT) and 56% special petroleum tax (SPT).

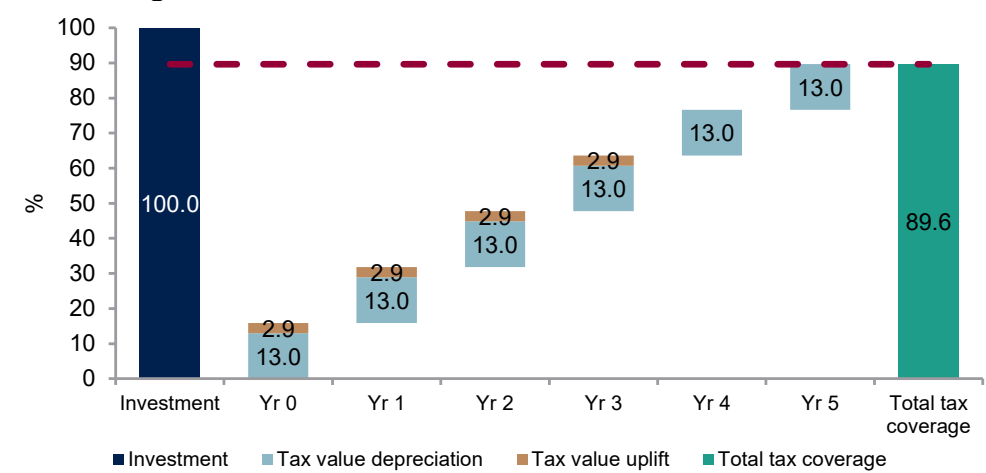
Depreciation: All field investments are depreciated in a straight line over six years, starting at the year of investment. This is eligible against CT and SPT (78%).

Uplift: Oil companies are eligible for a 20.8% allowance (5.2% per year over four years) on field investments against the SPT only.

Protection: Effectively this means that ~89.6% of the capital invested is protected in the tax system.

No ring-fencing: Offshore tax losses can be offset against any offshore income. The law, however, does not allow for pledging tax assets related to operations (special carve-out for exploration activities).

NCS tax regime



Source: ABG Sundal Collier, company data

The temporary tax regime for petroleum activities offshore Norway

In order to ensure oil company liquidity and stimulate offshore investments the Norwegian Parliament has imposed a temporary tax relief.

For investments made in 2020-2021:

Marginal tax rate: The marginal tax rate for petroleum activities offshore Norway is 78%, comprising of 22% corporate tax (CT) and 56% special petroleum tax (SPT). *This is unchanged from the ordinary petroleum tax system.*

Depreciation (CT): All field investments are depreciated in a straight line over six years, starting at the year of investment. This is eligible against CT (22%). *This is unchanged from the ordinary petroleum tax system.*

Depreciation (SPT): All field investments can be immediately expensed towards the SPT (56%). This also applies to development projects where a PDO has been submitted by YE'22 and approved by YE'23 for investments until first oil.

Uplift: Uplift can be immediately expensed towards the special petroleum tax (SPT); however, under the temporary tax regime the uplift allowance is increased from 20.8% to 24%. The increased uplift also applies to development projects where a PDO has been submitted by YE'22 and approved by YE'23 for investments until first oil sales.

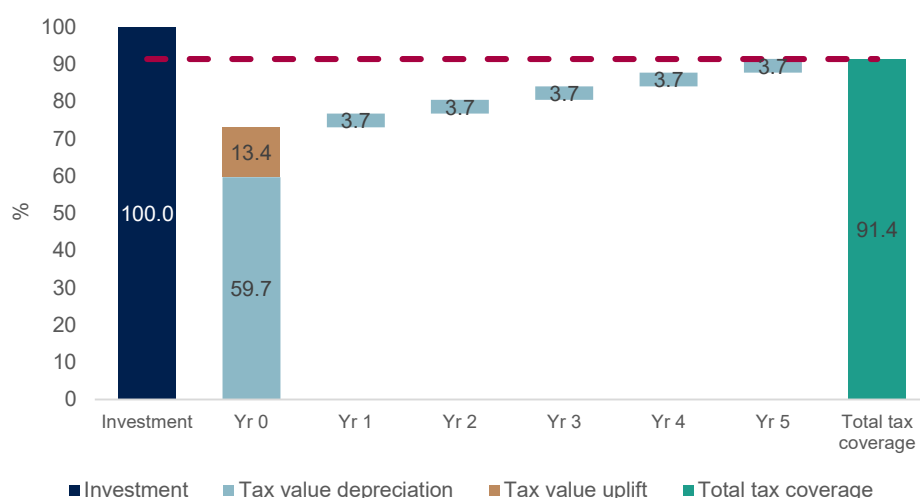
Tax loss refund: 2020 and 2021 tax losses can be claimed from the state (in cash). This can be done over six annual tax instalments.

Protection: The state now covers 91.4% of the capital invested.

No ring-fencing: Offshore tax losses can be offset against any offshore income. The law, however, does not allow for pledging tax assets related to operations (special carve-out for exploration activities). *This is unchanged from the ordinary petroleum tax system.*

Implication for the oil companies: The temporary change to the tax regime has both positive liquidity and NPV effects, and it improves the economics of projects.

Temporary NCS tax regime



Source: ABG Sundal Collier, company data

Exploration tax regime

Companies that are making a loss may choose between requesting an immediate refund of the tax value of exploration costs from the taxation authorities and carrying forward the losses with interest to a later year when the company has a taxable income.

This system ensures that the value of the tax deduction is the same whether or not a company is liable to pay tax, and that all companies are treated equally.

The reimbursement system is important for companies that are not yet in tax position, to enhance liquidity,

Each year the exploration company will declare to the Government the amount spent on exploration.

- Eligible costs includes costs related to exploration, research and development, operations and decommissioning

The tax element of the exploration costs (78%) is then reimbursed in Q4 the following year. Under the temporary tax regime exploration costs incurred in 2021 can be redeemed over three payments in H2'21 and three payments in H1'22.

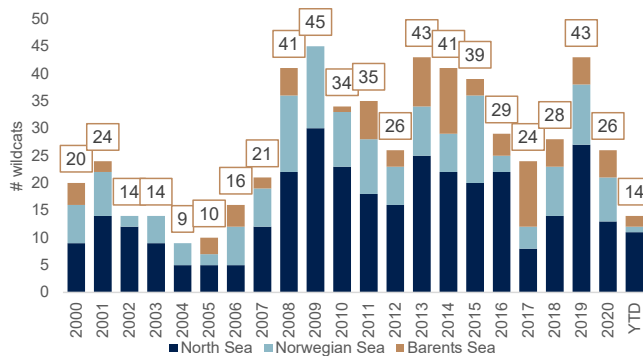
- The total tax rate of 78% comprise Corporate Tax of 22%, plus Special Petroleum Tax of 56%

The system allows for the small size oil companies to compete on equal terms with larger companies with existing production, and thereby stimulates exploration on the Norwegian Continental Shelf.

Exploration on the NCS

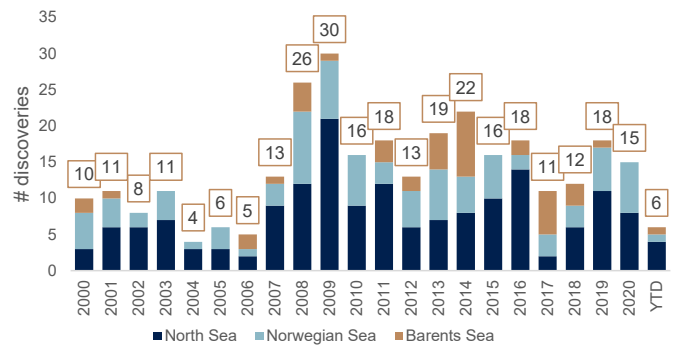
Historical data supports the strong rationale for exploration in mature areas, near existing infrastructure. On the NCS, the North Sea remains the main area both in terms of drilling and discoveries, and also in terms of resources. Nearly all exploration wells drilled in 2018-2019 were within reach for potential tie-back to existing infrastructure.

Wildcat exploration wells



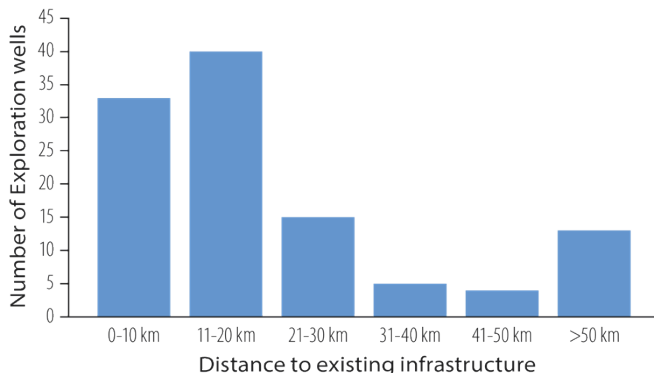
Source: NPD

Discoveries



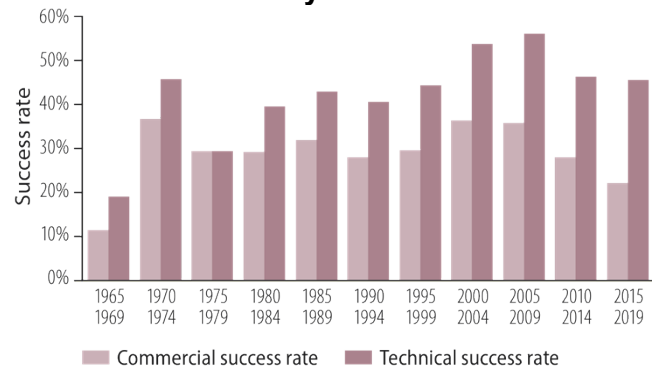
Source: NPD

Exploration wells 2018-19 and closeness to infrastructure



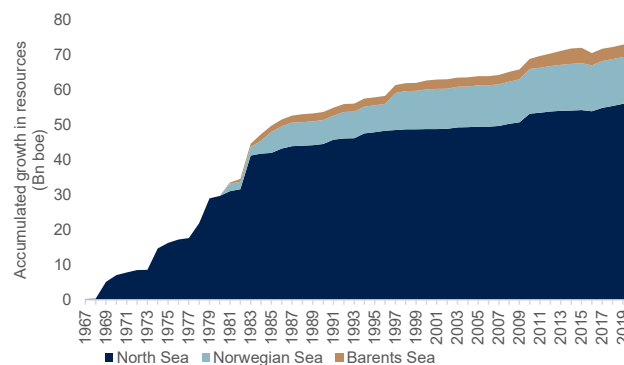
Source: NPD

Development of the average technical and commercial discovery rates



Source: NPD

Accumulated growth in resources



Source: Company data

Appendix - Board of Directors

Dr. Robert Arnott

Executive Chairman

Dr. Arnott is a geologist and board director with specialist competence within mature oil and gas provinces. He has held board-level positions at several E&P companies including Hurricane Energy plc, Rocksource ASA, Core Energy AS, Spring Energy AS and DNO ASA. Dr. Arnott started his career with Royal Dutch Shell before becoming an oil and gas equity analyst at both Goldman Sachs and Morgan Stanley.

Sjur Storås

Board Director

Mr. Storås has held several board-level positions at various oil and gas organisations and has been managing director of several companies within oil and gas such as CCB, the largest oil service base in Norway, and HOG, the main oil and gas interest organization in oil and gas in Hordaland county, Norway. Mr. Storås is today a partner at engineering and consulting company Head Energy Consulting AS and director of the board of Petrolia SE.

Brede Bjøvad Larsen

Board Director

Mr. Bjøvad Larsen is a professional investor. Mr. Bjøvad Larsen has been a board director at Petrolia NOCO AS since 2016, and also holds board-level positions at the oil services company Independent Oil Tools AS, as well as several private board roles. He holds a master's degree in global management from RBS London, UK.

Appendix - Management

Linn Katrine Høie

CEO

Ms. Høie is an oil industry executive focusing on the use of artificial intelligence, digitalisation and machine learning in the offshore oil and gas industry. Prior to joining Petrolia NOCO AS in 2019 Ms. Høie managed a digitalisation and project improvement project for Aker BP. Ms. Høie holds a MSc in Risk Management and Societal Safety from the University of Stavanger.

Jan Kaspar Gjessing

CFO

Mr. Gjessing joined Petrolia Noco from the position of Finance Manager at Corvus Energy. Prior to this, Gjessing held various financial controller and analyst roles with OMV Norge, Statoil (now Equinor) and Seadrill. He has also spent two years as an adviser within accounting. Mr. Gjessing holds a master's degree in finance from the Norwegian School of Economics and Business Administration (NHH).

Joanna Ponicka

Subsurface Manager

Ms. Ponicka has extensive experience on the NCS including several years of international experience as an explorationist. Her experience comprises of management of APA rounds, license management, and farm-ins/farm-downs activities. Ms. Ponicka is focused on discipline integration and increasing efficiency of exploration processes within Petrolia. Ms. Ponicka holds an MSc in Integrated Petroleum Geoscience from Aberdeen University, UK.

Asbjørn Holme

Business Development Manager

Mr. Holme has experience from ConocoPhillips holding various technical roles ranging from production engineering to reservoir characterization and reservoir modelling projects in the Greater Ekofisk Area. Prior to joining Petrolia Noco he was an integral part of the Tommeliten Alpha field development project. Mr. Holme is leading Petrolia Noco's reservoir processes and works closely together with the subsurface team. Mr. Holme holds an Msc in Petroleum Engineering from Norwegian University of Science and Technology and a Msc in Industrial Economics from University of Stavanger.

Kseniya Hladka

License Portfolio Manager

Ms. Hladka has more than 10 years of experience in E&P on NCS as well as internationally. Ms. Hladka started her career in Weatherford within integrated field development projects. Since 2012, Ms. Hladka's focus was on exploration licenses, identification of new opportunities and integrated subsurface approach in prospect de-risking. Ms. Hladka has held various subsurface roles in small oil companies, including Rocksource and Pure E&P, before joining Petrolia in 2017. Ms. Hladka holds a master's degree in Petroleum Geoscience from University of Bergen, and strategy, economics and digitalisation from BI.

Kristin Myhre

Safety & Sustainability

Ms. Myhre joins Petrolia Noco from a position as department manager and risk management consultant in Proactima AS. Prior to this, Ms. Myhre has also been with Lloyd's Register, Statoil (now Equinor) and Aker Kværner (now Aker Solutions).

She has worked as an advisor and consultant for more than 10 years, performing analyses within safety, risk management, working environment and emergency preparedness. Ms. Myhre also has 12 years' experience as a safety/HSE discipline manager & engineer in oil and gas projects on the Norwegian Continental Shelf. Ms. Myhre holds a master's degree in Industrial Environmental Technology from 1996, and a bachelor's degree in Analytical Chemistry from 1994.

Appendix - Shareholders

Top 20 shareholders, as per 27 May 2021

Investor	Number of shares	% of top 20	% of total	Type	Country
PETROLIA AS	48,484,331	37.03%	36.37%	Comp.	NOR
NOCO (UK) LTD	24,842,496	18.98%	18.64%	Comp.	GBR
PETROLIA SE	18,032,000	13.77%	13.53%	Comp.	CYP
INCREASED OIL RECOVERY AS	16,144,165	12.33%	12.11%	Comp.	NOR
NOCO OIL & RESOURCES LTD	6,423,550	4.91%	4.82%	Comp.	CYP
LARSEN OIL & GAS AS	5,537,595	4.23%	4.15%	Comp.	NOR
TIME CRITICAL PETROLEUM RESOURCES	5,461,346	4.17%	4.10%	Comp.	NOR
INDEPENDENT OIL & RESOURCES PLC	2,842,528	2.17%	2.13%	Comp.	NOR
TOKALA AS	1,107,605	0.85%	0.83%	Comp.	NOR
ASKAS AS	314,070	0.24%	0.24%	Comp.	NOR
EGD CAPITAL AS	272,116	0.21%	0.20%	Comp.	NOR
SERIOUS AS	216,906	0.17%	0.16%	Comp.	NOR
SVENDSEN GEIR ARILD	195,472	0.15%	0.15%	Priv.	NOR
SILVERCOIN INDUSTRIES AS	167,122	0.13%	0.13%	Comp.	NOR
EQUIVEST AS	160,900	0.12%	0.12%	Comp.	NOR
HAVLI AS	151,584	0.12%	0.11%	Comp.	NOR
HANSTVEIT JON	149,312	0.11%	0.11%	Priv.	NOR
DAHLE BJØRN	141,613	0.11%	0.11%	Priv.	NOR
MILLYEN AS	139,979	0.11%	0.11%	Comp.	NOR
SELACO AS	136,333	0.10%	0.10%	Comp.	NOR
Total number owned by top 20	130,921,023	100%	98.22%		
Total number of shares	133,300,000		100%		

Source: ABG Sundal Collier, company data

Appendix - Risks

We view the main risks to the company as:

Oil and gas prices

Petrolia Noco is exposed to adverse shifts in oil and gas prices.

Currency risk

The functional currencies are USD and NOK, while the trading currency is NOK, i.e. Petrolia Noco is exposed to adverse currency fluctuations.

Funding requirement

Dependent on monetization strategy for the Dugong discovery, Petrolia Noco could have a funding gap to meet its partner obligations.

Exploration success

As an exploration company, exploration success is a key risk to the investment case.

Project development and execution

Petrolia Noco and its partners' ability to execute projects according to the schedule and on budget. In particular this relates to the bringing the Dugong discovery to PDO YE'22 and later to production.

Abandonment liabilities

Petrolia Noco is exposed to abandonment liabilities related to its stakes in Enoch and Flyndre.

Illiquid share

There is low liquidity in the share.

Income Statement (NOKm)	Q2 2019	Q3 2019	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021
Sales	11	0	9	0	2	0	2	3
COGS	-73	0	-32	0	-36	0	-42	-35
Gross profit	-62	0	-23	0	-34	0	-40	-32
Other operating items	0	0	0	0	0	0	0	0
EBITDA	-62	0	-23	0	-34	0	-40	-32
Depreciation and amortisation	-1	0	-2	0	-1	0	-3	0
EBITA	-63	0	-26	0	-35	0	-43	-32
EO items	0	0	0	0	0	0	0	0
Impairment and PPA amortisation	0	0	0	0	0	0	0	0
EBIT	-63	0	-26	0	-35	0	-43	-32
Net financial items	-2	0	-3	0	-4	0	-4	-1
Pretax profit	-64	0	-29	0	-39	0	-48	-33
Tax	50	0	21	0	28	0	31	26
Net profit	-14	0	-8	0	-11	0	-16	-7
Minority interest	0	0	0	0	0	0	0	0
Net profit discontinued	0	0	0	0	0	0	0	0
Net profit to shareholders	-14	0	-8	0	-11	0	-16	-7
EPS	0	0	-0.07	0	-0.09	0	-0.12	-0.05
EPS Adj	0	0	-0.07	0	-0.09	0	-0.12	-0.05
Total extraordinary items after tax	0	0	0	0	0	0	0	0
Tax rate (%)	78.2	ns	71.1	ns	72.3	ns	66.1	78.2
Gross margin (%)	-577.2	nm	-267.4	nm	-1,945.1	nm	-1,875.7	-914.2
EBITDA margin (%)	-577.2	nm	-267.4	nm	-1,945.1	nm	-1,875.7	-914.2
EBITA margin (%)	-585.2	nm	-295.9	nm	-2,005.1	nm	-2,031.6	-914.2
EBIT margin (%)	-585.2	nm	-295.9	nm	-2,005.1	nm	-2,031.6	-914.2
Pretax margin (%)	-601.0	nm	-335.6	nm	-2,204.8	nm	-2,238.3	-951.1
Net margin (%)	-131.2	nm	-96.9	nm	-610.2	nm	-758.5	-207.7
Growth rates Y/Y	Q2 2019	Q3 2019	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021
Sales growth (%)	+chg	na	+chg	na	-83.5	na	-75.5	+chg
EBITDA growth (%)	-chg	na	-chg	na	+chg	na	-chg	-chg
EBIT growth (%)	-chg	na	-chg	na	+chg	na	-chg	-chg
Net profit growth (%)	-chg	na	-chg	na	+chg	na	-chg	-chg
EPS growth (%)	-chg	na	-chg	na	+chg	na	-chg	-chg
Adj earnings numbers	Q2 2019	Q3 2019	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021
EBITDA Adj	-62	0	-23	0	-34	0	-40	-32
EBITDA Adj margin (%)	-577.2	nm	-267.4	nm	-1,945.1	nm	-1,875.7	-914.2
EBITA Adj	-63	0	-26	0	-35	0	-43	-32
EBITA Adj margin (%)	-585.2	nm	-295.9	nm	-2,005.1	nm	-2,031.6	-914.2
EBIT Adj	-63	0	-26	0	-35	0	-43	-32
EBIT Adj margin (%)	-585.2	nm	-295.9	nm	-2,005.1	nm	-2,031.6	-914.2
Pretax profit Adj	-64	0	-29	0	-39	0	-48	-33
Net profit Adj	-14	0	-8	0	-11	0	-16	-7
Net profit to shareholders Adj	-14	0	-8	0	-11	0	-16	-7
Net Adj margin (%)	-131.2	nm	-96.9	nm	-610.2	nm	-758.5	-207.7

Source: ABG Sundal Collier, Company data

Income Statement (NOKm)	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
Sales	0	0	0	0	0	19	4	14	9	5
COGS	0	0	0	0	0	-104	-78	-337	-128	-45
Gross profit	0	0	0	0	0	-85	-74	-323	-119	-40
Other operating items	0	0	0	0	0	0	0	-0	0	0
EBITDA	0	0	0	0	0	-85	-74	-323	-119	-40
Depreciation and amortisation	0	0	0	0	0	-3	-4	-1	-2	-1
Of which leasing depreciation	0	0	0	0	0	0	0	0	0	0
EBITA	0	0	0	0	0	-88	-79	-325	-121	-41
EO items	0	0	0	0	0	0	0	0	0	0
Impairment and PPA amortisation	0	0	0	0	0	0	0	0	0	0
EBIT	0	0	0	0	0	-88	-79	-325	-121	-41
Net financial items	0	0	0	0	0	-5	-8	-16	-21	-14
Pretax profit	0	0	0	0	0	-93	-87	-341	-142	-55
Tax	0	0	0	0	0	71	60	266	111	46
Net profit	0	0	0	0	0	-22	-27	-75	-31	-8
Minority interest	0	0	0	0	0	0	0	0	0	0
Net profit discontinued	0	0	0	0	0	0	0	0	0	0
Net profit to shareholders	0	0	0	0	0	-22	-27	-75	-31	-8
EPS	0	0	0	0	0	-0.18	-0.20	-0.52	-0.21	-0.06
<i>EPS Adj</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>-0.18</i>	<i>-0.20</i>	<i>-0.52</i>	<i>-0.21</i>	<i>-0.06</i>
Total extraordinary items after tax	0	0	0	0	0	0	0	0	0	0
Leasing payments	0	0	0	0	0	0	0	0	0	0
<i>Tax rate (%)</i>	<i>ns</i>	<i>ns</i>	<i>ns</i>	<i>ns</i>	<i>ns</i>	<i>76.0</i>	<i>68.9</i>	<i>78.1</i>	<i>78.2</i>	<i>84.8</i>
<i>Gross margin (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-438.6</i>	<i>-1,907.2</i>	<i>-2,388.3</i>	<i>-1,259.6</i>	<i>-722.6</i>
<i>EBITDA margin (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-438.6</i>	<i>-1,907.2</i>	<i>-2,388.3</i>	<i>-1,259.6</i>	<i>-722.6</i>
<i>EBITA margin (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-455.8</i>	<i>-2,019.5</i>	<i>-2,397.5</i>	<i>-1,282.0</i>	<i>-744.1</i>
<i>EBIT margin (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-455.8</i>	<i>-2,019.5</i>	<i>-2,397.5</i>	<i>-1,282.0</i>	<i>-744.1</i>
<i>Pretax margin (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-482.3</i>	<i>-2,223.1</i>	<i>-2,517.2</i>	<i>-1,502.3</i>	<i>-994.8</i>
<i>Net margin (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-115.9</i>	<i>-691.0</i>	<i>-552.5</i>	<i>-327.6</i>	<i>-151.3</i>
Growth rates Y/Y	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
<i>Sales growth (%)</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>-79.9</i>	<i>247.9</i>	<i>-30.3</i>	<i>-41.8</i>
<i>EBITDA growth (%)</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>high</i>	<i>12.7</i>	<i>-335.6</i>	<i>63.2</i>	<i>66.6</i>
<i>EBIT growth (%)</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>high</i>	<i>11.0</i>	<i>-313.0</i>	<i>62.7</i>	<i>66.2</i>
<i>Net profit growth (%)</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>high</i>	<i>-19.8</i>	<i>-178.1</i>	<i>58.7</i>	<i>73.1</i>
<i>EPS growth (%)</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>high</i>	<i>-9.2</i>	<i>-155.7</i>	<i>58.7</i>	<i>73.1</i>
Profitability	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
<i>ROE (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-165.2</i>	<i>-78.1</i>	<i>-302.5</i>	<i>403.6</i>	<i>30.5</i>
<i>ROE Adj (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-165.2</i>	<i>-78.1</i>	<i>-302.5</i>	<i>403.6</i>	<i>30.5</i>
<i>ROCE (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-144.9</i>	<i>-72.0</i>	<i>-172.3</i>	<i>-62.2</i>	<i>-105.6</i>
<i>ROCE Adj(%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-144.9</i>	<i>-72.0</i>	<i>-172.3</i>	<i>-62.2</i>	<i>-105.6</i>
<i>ROIC (%)</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>-41.9</i>	<i>-22.3</i>	<i>-24.8</i>	<i>-7.1</i>	<i>-2.0</i>
<i>ROIC Adj (%)</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>na</i>	<i>-41.9</i>	<i>-22.3</i>	<i>-24.8</i>	<i>-7.1</i>	<i>-2.0</i>
Adj earnings numbers	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
EBITDA Adj	0	0	0	0	0	-85	-74	-323	-119	-40
<i>EBITDA Adj margin (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-438.6</i>	<i>-1,907.2</i>	<i>-2,388.3</i>	<i>-1,259.6</i>	<i>-722.6</i>
EBITDA lease Adj	0	0	0	0	0	-85	-74	-323	-119	-40
<i>EBITDA lease Adj margin (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-438.6</i>	<i>-1,907.2</i>	<i>-2,388.3</i>	<i>-1,259.6</i>	<i>-722.6</i>
EBITA Adj	0	0	0	0	0	-88	-79	-325	-121	-41
<i>EBITA Adj margin (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-455.8</i>	<i>-2,019.5</i>	<i>-2,397.5</i>	<i>-1,282.0</i>	<i>-744.1</i>
EBIT Adj	0	0	0	0	0	-88	-79	-325	-121	-41
<i>EBIT Adj margin (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-455.8</i>	<i>-2,019.5</i>	<i>-2,397.5</i>	<i>-1,282.0</i>	<i>-744.1</i>
Pretax profit Adj	0	0	0	0	0	-93	-87	-341	-142	-55
Net profit Adj	0	0	0	0	0	-22	-27	-75	-31	-8
Net profit to shareholders Adj	0	0	0	0	0	-22	-27	-75	-31	-8
<i>Net Adj margin (%)</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>nm</i>	<i>-115.9</i>	<i>-691.0</i>	<i>-552.5</i>	<i>-327.6</i>	<i>-151.3</i>

Source: ABG Sundal Collier, Company data

Cash Flow Statement (NOKm)	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
EBITDA	0	0	0	0	0	-85	-74	-323	-119	-40
Net financial items	0	0	0	0	0	-5	-8	-16	-21	-14
Paid tax	0	0	0	0	0	0	57	267	211	121
Non-cash items	0	0	0	0	0	-25	36	0	0	0
Cash flow before change in WC	0	0	0	0	0	-115	10	-73	71	67
Change in WC	0	0	0	0	0	73	57	295	86	0
Operating cash flow	0	0	0	0	0	-43	67	222	158	67
CAPEX tangible fixed assets	0	0	0	0	0	-2	-69	-486	-131	-183
CAPEX intangible fixed assets	0	0	0	0	0	0	0	0	0	0
Acquisitions and disposals	0	0	0	0	0	0	0	0	0	0
Free cash flow	0	0	0	0	0	-45	-2	-264	27	-115
Dividend paid	0	0	0	0	0	0	0	0	0	0
Share issues and buybacks	0	0	0	0	0	0	0	41	0	0
Lease liability amortisation	0	0	0	0	0	0	0	0	0	0
Other non cash items	0	0	0	0	0	0	0	0	0	0
Balance Sheet (NOKm)	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
Goodwill	0	0	0	0	0	0	0	0	0	0
Other intangible assets	0	0	0	0	0	0	0	0	0	0
Tangible fixed assets	0	0	0	0	0	1	8	7	21	202
Right-of-use asset	0	0	0	0	0	0	0	0	0	0
Total other fixed assets	0	0	0	0	0	33	74	264	293	293
Fixed assets	0	0	0	0	0	33	82	272	314	495
Inventories	0	0	0	0	0	20	30	30	30	30
Receivables	0	0	0	0	0	0	0	0	0	0
Other current assets	0	0	0	0	0	71	42	192	-20	-20
Cash and liquid assets	0	0	0	0	0	21	18	13	-101	-348
Total assets	0	0	0	0	0	145	171	505	223	157
Shareholders equity	0	0	0	0	0	27	42	8	-23	-31
Minority	0	0	0	0	0	0	0	0	0	0
Total equity	0	0	0	0	0	27	42	8	-23	-31
Long-term debt	0	0	0	0	0	95	55	273	132	0
Pension debt	0	0	0	0	0	0	0	0	0	0
Convertible debt	0	0	0	0	0	0	0	0	0	0
Leasing liability	0	0	0	0	0	0	0	0	0	0
Total other long-term liabilities	0	0	0	0	0	4	41	191	80	34
Short-term debt	0	0	0	0	0	0	0	0	0	0
Accounts payable	0	0	0	0	0	7	3	3	3	3
Other current liabilities	0	0	0	0	0	12	30	30	30	151
Total liabilities and equity	0	0	0	0	0	145	171	505	223	157
Net IB debt	0	0	0	0	0	70	35	258	231	346
Net IB debt excl. pension debt	0	0	0	0	0	70	35	258	231	346
Net IB debt excl. leasing	0	0	0	0	0	70	35	258	231	346
Capital invested	0	0	0	0	0	101	118	457	288	348
Working capital	0	0	0	0	0	72	38	187	-24	-145
EV breakdown	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
Market cap. diluted (m)	na	na	na	na	na	60	400	500	500	500
Net IB debt Adj	0	0	0	0	0	70	35	258	231	346
Market value of minority	0	0	0	0	0	0	0	0	0	0
Reversal of shares and participations	0	0	0	0	0	0	0	0	0	0
Reversal of conv. debt assumed equity	0	0	0	0	0	0	0	0	0	0
EV	na	na	na	na	na	130	435	758	731	846
Capital efficiency	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
Total assets turnover (%)	nm	nm	nm	nm	nm	26.8	2.5	4.0	2.6	2.9
Working capital/sales (%)	nm	nm	nm	nm	nm	184.9	1,408.2	832.1	867.3	-1,531.0
Financial risk and debt service	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
Net debt/equity	nm	nm	nm	nm	nm	2.59	0.83	33.07	-9.98	-11.01
Net debt/market cap	na	na	na	na	na	1.17	0.21	0.52	0.46	0.69
Equity ratio (%)	nm	nm	nm	nm	nm	18.8	24.3	1.5	-10.4	-20.0
Net IB debt adj./equity	nm	nm	nm	nm	nm	2.59	0.83	33.07	-9.98	-11.01
Current ratio	nm	nm	nm	nm	nm	5.84	2.64	6.90	-2.68	-2.18
EBITDA/net interest	na	na	na	na	na	-16.55	-9.37	-19.96	-5.72	-2.88
Net IB debt/EBITDA	nm	nm	nm	nm	nm	-0.83	-0.47	-0.80	-1.94	-8.72
Net IB debt/EBITDA lease Adj	nm	nm	nm	nm	nm	-0.83	-0.47	-0.80	-1.94	-8.72
Interest cover	nm	nm	nm	nm	nm	-17.20	-9.92	-20.03	-5.82	-2.97

Source: ABG Sundal Collier, Company data

Valuation and Ratios (NOKm)	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
Shares outstanding adj.	0	0	0	0	0	121	133	145	145	145
Fully diluted shares Adj	0	0	0	0	0	121	133	145	145	145
EPS	0	0	0	0	0	-0.18	-0.20	-0.52	-0.21	-0.06
Dividend per share Adj	0	0	0	0	0	0	0	0	0	0
EPS Adj	0	0	0	0	0	-0.18	-0.20	-0.52	-0.21	-0.06
BVPS	0	0	0	0	0	0.22	0.31	0.05	-0.16	-0.22
BVPS Adj	0	0	0	0	0	0.22	0.31	0.05	-0.16	-0.22
Net IB debt / share	na	na	na	na	na	0.6	0.3	1.8	1.6	2.4
Share price	na	na	na	na	na	0.49	3.00	3.45	3.45	3.45
Market cap. (m)	na	na	na	na	na	60	400	500	500	500
Valuation	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
P/E	na	na	na	na	na	-2.7	-14.9	-6.7	-16.2	-60.2
EV/sales	na	na	na	na	na	6.70	111.66	55.98	77.43	154.06
EV/EBITDA	na	na	na	na	na	-1.5	-5.9	-2.3	-6.1	-21.3
EV/EBITA	na	na	na	na	na	-1.5	-5.5	-2.3	-6.0	-20.7
EV/EBIT	na	na	na	na	na	-1.5	-5.5	-2.3	-6.0	-20.7
Dividend yield (%)	na	na	na	na	na	0	0	0	0	0
FCF yield (%)	na	na	na	na	na	-74.8	-0.6	-52.8	5.4	-23.0
Lease adj. FCF yield (%)	na	na	na	na	na	-74.8	-0.6	-52.8	5.4	-23.0
P/BVPS	na	na	na	na	na	2.19	9.60	64.13	-21.63	-15.91
P/BVPS Adj	na	na	na	na	na	2.19	9.60	64.13	-21.63	-15.91
P/E Adj	na	na	na	na	na	-2.7	-14.9	-6.7	-16.2	-60.2
EV/EBITDA Adj	na	na	na	na	na	-1.5	-5.9	-2.3	-6.1	-21.3
EV/EBITA Adj	na	na	na	na	na	-1.5	-5.5	-2.3	-6.0	-20.7
EV/EBIT Adj	na	na	na	na	na	-1.5	-5.5	-2.3	-6.0	-20.7
EV/cap. employed	na	na	na	na	na	1.1	4.5	2.7	6.7	-26.9
Investment ratios	2014	2015	2016	2017	2018	2019	2020	2021e	2022e	2023e
Capex/sales	nm	nm	nm	nm	nm	10.3	1,780.4	3,588.2	1,382.4	3,325.6
Capex/depreciation	nm	nm	nm	nm	nm	60.1	1,585.3	39,053.6	6,194.4	15,470.5
Capex tangibles/tangible fixed assets	nm	nm	nm	nm	nm	218.7	897.0	6,526.0	625.5	90.3
Capex intangibles/definite intangibles	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
Depreciation on intangibles/definite intangible assets	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
Depreciation on tangibles/tangibles	nm	nm	nm	nm	nm	363.9	56.6	16.7	10.1	0.6

Source: ABG Sundal Collier, Company data

Analyst certification

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