Oil and Gas exploration in Greenland

RESOURCES, ECONOMY AND ENVIRONMENTAL ISSUES RELATED TO GREENLAND'S FUTURE HYDROCARBON POLICY

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1 Dansk resumé

Formålet med denne rapport er at give politiske beslutningstagere baggrund for at vurdere sandsynligheden for, at Grønland kan blive et olieeksportland i fremtiden, samt vurdere det økonomiske potentiale og de miljømæssige udfordringer. Der er i analysen taget udgangspunkt i internationale kilder og rapporter fra Grønland. Herunder især fra Nunaoil A/S (det nationale olieselskab i Grønland) og en række afdelinger i den grønlandske statsadministration.

Historisk overblik over efterforskning af olie i Grønland og Arktis

Opdagelsen af Prudhoe Bay oliefeltet i Alaska ved udgangen af 1960'erne ansporede en interesse i olieefterforskning i de Arktiske egne, inklusive Grønland, yderligere drevet af en høj oliepris i de tidlige 1970'ere grundet den første oliekrise.

Fra begyndelsen var aktiviteter relateret til kulbrinteefterforskning og udnyttelse i Grønland administreret af Grønlandsministeriet i København. I 1979 fik Grønland en Hjemmestyre ordning og derefter flyttede beslutninger relateret til kulbrinteefterforskning og udnyttelse ind i det nyoprettede Fællesråd vedrørende Mineralske Råstoffer i Grønland, bestående af politikere fra de to respektive parlamenter (Folketinget og Landstinget). I perioden mellem 1979 og 1999 blev de administrative opgaver behandlet i et kontor i København (Råstofforvaltningen for Grønland), men i 1999 flyttede administrationen til Råstofstyrelsen i Nuuk (Christiansen, 2011).

I 1974 fik seks grupper af selskaber, opereret af hhv. Amoco, ARCO, Chevron, Mobil, Total og Ultramar, tildelt i alt 13 offshore efterforskningslicenser dækkende et samlet areal på 19082 km^2 udfor Grønlands vestkyst (Christiansen, 2011). I løbet af de følgende år blev der boret fem efterforskningsbrønde, men af de fem brønde var det kun den første, Kangâmiut-1-brønden, der stødte på kulbrinter i form af gas, men på grund af tekniske problemer flød brønden aldrig. I begyndelsen af 1979 blev alle licenser frigivet, og offshore-efterforskning ophørte indtil 1996.

I løbet af 1980'erne fandt efterforskning kun sted på Jameson Land, hvor ARCO, Arktisk Minekompagni A/S og Nunaoil A/S underskrev en koncessionsaftale i januar 1985 for et areal på ca. 10.000 km2 og erhvervede i alt 1.798 km 2D seismiske data i perioden 1985-1989. Ved udgangen af 1990 blev licensen afstået, hovedsagelig på grund af fald i oliepriserne, og lave forventninger om et kommercielt fund.

Som en del af en ny efterforskningsstrategi formuleret i de tidlige 1990'ere, blev en ny licensrunde åbnet i 1992, men ved dens afslutning i 1993 var der ikke indkommet ansøgninger og det blev besluttet at have en åbendør politik for Vest Grønlandske farvande syd for 70°30'N.

I 1996 blev Statoil og dets partnere (Phillips, DONG og NUNAOIL) tildelt en efterforskningslicens i sydvest Grønland, udenfor den normale licensrunde procedure. Resultaterne var skuffende og nedgraderede den forventede lønsomhed i området. Ved udgangen af 2001 tilbageleverede konsortiet licensen.

Et strategisk indsamlingsprogram af olieudsivninger på Disko og Nuussuaq i de tidlige 1990'ere skabte en del interesse fra industrien, resulterende i en ansøgning for en forundersøgelsestilladelse fra GrønArctic i 1994 og en efterforsknings- og udnyttelsestilladelse i 1995 (Christiansen, 2011). De første boringer gav lovende resultater, men en senere brønd var mindre lovende, og i midten af 1998 tilbageleverede GrønArctic deres licens (Christiansen, 2011).

Efter forhandlinger mellem de tidligere myndigheder, Nunaoil A/S og olieindustrien, blev det såkaldte KANUMAS-projekt (Kalaallit Nunaat Marine Seismic) igangsat i 1989, og en forundersøgelsestilladelse udstedt til et konsortium bestående af de seks selskaber: BP, Exxon, Japan National Oil Company, Shell, Statoil and Texaco, med NUNAOIL som båren partner og operatør for konsortiet (Christiansen, 2011).

Igennem 2000'erne åbnede licensrunder i farvandene ud for Vest Grønland og i Disko Vest området. Som et resultat af denne aggressive dataindsamling og de mange licensrunder, blev Atammik licensen (3985 km2) tildelt i 2002 til EnCana efterfulgt af en anden tildeling til Encana med tildelingen af Lady Franklin licensen (2897 km2) i 2005 (Christiansen, 2011).

Disko Vest licensrunden skete i to faser, med en begyndende fase med otte prædefinerede blokke vest for Disko og en senere anden fase igennem et åbendør tildelingssystem. De prædefinerede blokke havde størrelse på mere end 10.000 km2 til knap 14.000 km2 og i forbindelse med den første fase blev syv af de otte blokke tildelt i 2007 og 2008 til grupper bestående af en kombination af store olieselskaber (f.eks. Chevron og ExxonMobil) og mellem store selskaber (Cairn, DONG, Husky og PA Resources) (Christiansen, 2011). Som en del af åbendør tildelingssystemet, søgte Cairn og fik tildelt fire store efterforskningslicenser (> 10.000 km2 per blok) omkring Kap Farvel samt købte sig ind EnCana's to licenser (Atammik og Lady Franklin; Christiansen, 2011)

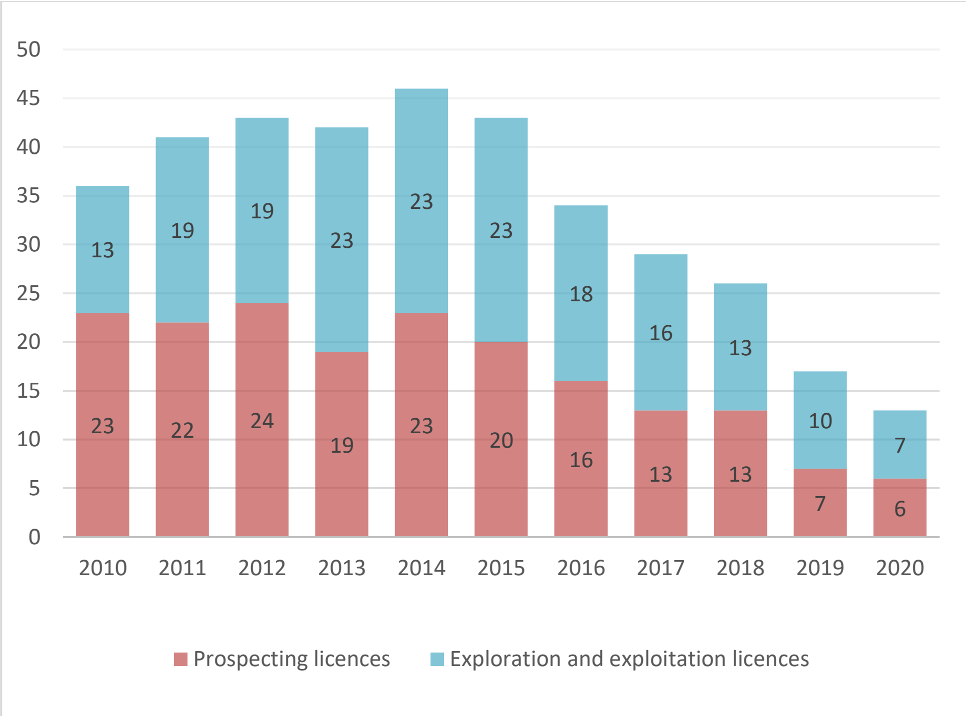
I 2008 erhvervede Husky de første 3D seismiske undersøgelser på den grønlandske sokkel i deres to licensblokke (Kangerluk og Ikermiut - i alt 2.171 km2), der viste, at det var muligt at indhente denne type data i isbjerginficerede områder. Senere i 2011 og 2012 blev 3D-seismisk erhvervelse anskaffet under endnu hårdere forhold i Baffin Bay og Cap Farewell. I 2015 var alle efterforskningslicenser i Disko West imidlertid blevet opgivet på grund af vanskeligheder med at finde attraktive boremål i de udfordrende og vulkandækkede licensområder.

En ny licensrunde for Baffin Bay i 2010 blev en succes med 17 ansøgninger fra 12 virksomheder og tildeling af syv licenser. Ansøgningerne bestod af store internationale virksomheder (f.eks. ConocoPhillips, Shell, Statoil) og mellemstore virksomheder (f.eks. Cairn Energy, DONG, Faroe Petroleum, Mærsk). I begyndelsen af 2011 blev syv efterforsknings- og produktionstilladelser tildelt fem forskellige konsortier. I juni 2014 faldt verdensmarkedsprisen på råolie, hvilket mindskede udsigterne til kommerciel succes i Baffin Bay, og selskaberne besluttede at opgive deres licenser frem mod 2015.

I begyndelsen af 2011 åbnede de grønlandske myndigheder en tofaset licensrunde i Grønlandshavet (NØ Grønland). Licensområdet bestod af 19 foruddefinerede blokke, der dækkede et samlet areal på 50.000 km2, nomineret af KANUMAS-gruppen (BP, Exxon, JNOC, Shell, Statoil, Texaco). I den første fase blev der tilbudt foruddefinerede blokke, der dækkede et areal på 30.000 km2, og forbeholdt konsortier, der omfattede mindst et af KANUMAS-selskaberne. Ved fristen i december 2012 blev fire licenser tildelt tre konsortier. I anden fase blev der givet yderligere én licens, så det samlede antal licenser i Grønlandshavet var fem. De høje omkostninger til dataanskaffelse, den lave oliepris og de ekstremt høje omkostninger til bore- og udviklingsaktiviteter betød, at selskaberne opgav deres licenser ved udgangen af 2010'erne (2018 og 2019).

Grønlands olie- og gasaktiviteter og anslåede kulbrinteressourcer

Fra februar 2021 var der seks aktive efterforskningslicenser og fire aktive efterforsknings- og udnyttelseslicenser i Grønland. Dette repræsenterer et langt og støt fald (se Figur 1) i forhold til perioden 2010-2015.



Figur 1: Antal kulbrintelicenser i Grønland. Bemærk, at antallet af efterforsknings- og udnyttelseslicenser inkluderer licenser under en overdragelsesproces.

I 2020 lancerede Grønlands regering en ny olie- og gasstrategi, der dækker perioden 2020-2024. Strategien inkluderer en plan for åbning af licensrunder og åben-dør procedurer. Strategien har fokus på onshore efterforskning på Nuussuaq-halvøen, hvor Naalakkersuisut (Grønlands regering) har fået gennemført en række geologiske undersøgelser.

Resurseevalueringsprojektet for hele Grønland (Whole of Greenland Resource Assessment,WOGA) har nu afsluttet en ressourcevurdering for den vestgrønlandske sokkel. Resultaterne indikerer en middel ressource på mere end 18 mia. tønder olieækvivalent med det største potentiale i Baffin Bay-området. En tidligere USGS-ressourcevurdering anvendte en anden metode og dækkede et område, der var ca. 20% større, men dets resultater var i samme størrelsesorden, nemlig 17 milliarder tønder olieækvivalenter.

WOGA-vurderingen for den Østgrønlandske sokkel er endnu ikke afsluttet, men en tidligere USGS-vurdering tyder på, at ressourcerne her kan være næsten dobbelt så store som i Vestgrønland. USGS 2007-ressourcevurdering anslår således et potentiale på 31,4 mia tønder olieækvivalent. Der forventes opdaterede ressourceestimater fra WOGA i foråret 2021.

Miljøeffekter af olieefterforskning og -udvinding

Bl.a. på grund af den arktiske placering har miljø stor opmærksomhed for Grønlands regering. Derfor skal al kulbrintefterforskning i Grønland følge "Best Practice" og de højeste internationale standarder. Når man ansøger om en licens eller en aktivitet i Grønland, vurderes miljø-, natur- og klimaspørgsmål vedrørende mineralressourceaktiviteter af Miljøstyrelsen for Råstofområdet (MR). Arktiske og subarktiske miljøer har lav biodiversitet, sårbare fødekæder samt få nøglearter, der spiller en vigtig rolle i regionens økologi.

Havis og isbjerge er vigtige faktorer i forhold til olie- og gasaktiviteter, da det gør driften mere kompleks. Havisforholdene har varieret betydeligt gennem årene, men den generelle tendens er et fald i mængden af havis. Vigtige miljøpåvirkninger er relaterede til støj, udslip af boreslam og produktionsvand, samt indplacering af faste strukturer.

Langt den største potentielle miljøpåvirkning ville være fra et stort olieudslip. Større olieudslip i forbindelse med olieefterforskning kan ske ved en udblæsning (blow-out) eller som spild fra tankskibe ved produktion. Et større oliespild i Grønland kunne få massive konsekvenser for miljøet. Oliespild fra olieefterforskning er dog sjældne, og som tidligere nævnt kræves høje sikkerhedsstandarder, især når man arbejder i et arktisk miljø.

Olie og Klima

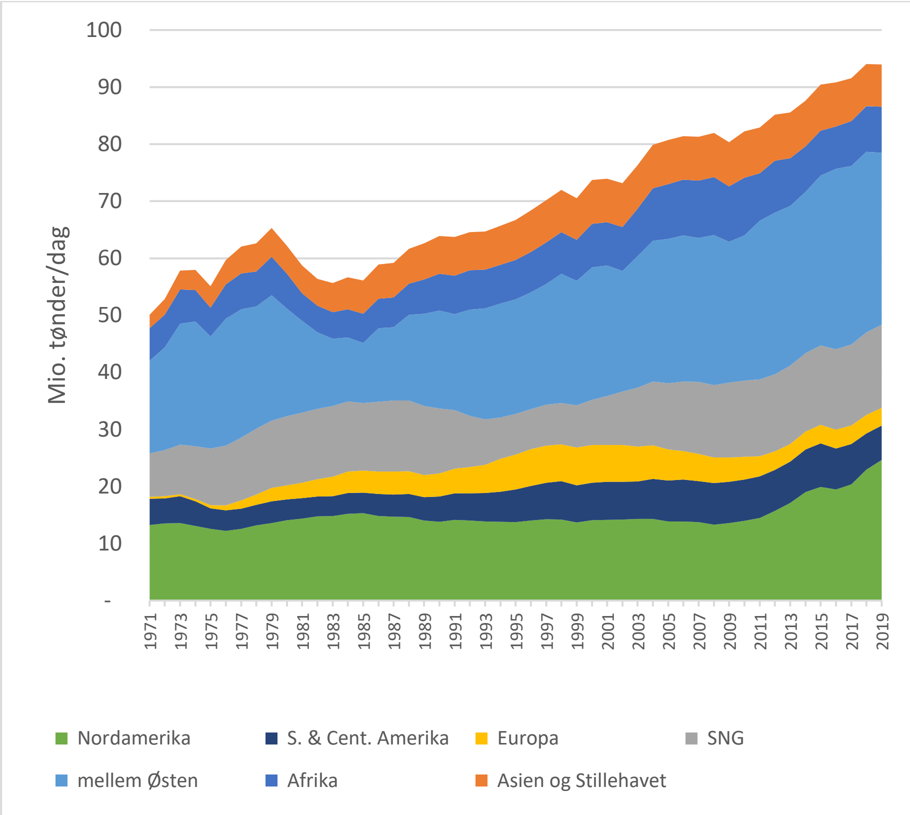
Parisaftalen er en juridisk bindende international aftale om klimaændringer, der blev vedtaget af 196 parter ved COP 21 i Paris den 12. december 2015. Aftalen trådte i kraft den 4. november 2016 (IPCC). Målet med aftalen er at begrænse den globale opvarmning til "væsentligt under 2, helst til 1,5 grader °C sammenlignet med førindustrielle niveauer". For at nå dette langsigtede klimamål, sigter landene mod at nå et maksimum for udledning af drivhusgasser så hurtigt som muligt for at opnå klimaneutralitet inden midten af århundredet. Baseret på et globalt olieforbrug på knap 100 mio. tønder/dag i 2019 (EIA), udgøres den direkte CO2-emission fra forbrænding af olie til energiformål ca. 14 mia. ton CO2, en tredjedel af den globale emission.

Den globale olieefterspørgsel samt priser og politikker

Siden oliekriserne i 1970'erne er den globale efterspørgsel efter olie steget støt med gennemsnitligt 1,5% om året til det nuværende niveau på knap 100 mia. tønder/dag[1]. Olie udgør ca. 30% af den globale primære energiforsyning, en dominerende rolle der dog forventes langsomt at falde fremadrettet.

[1] En tønde olie svarer til ca. 6,1 GigaJoule (GJ). 100 mio tønder/dag svarer til ca. 220 Exajoule (EJ) /år

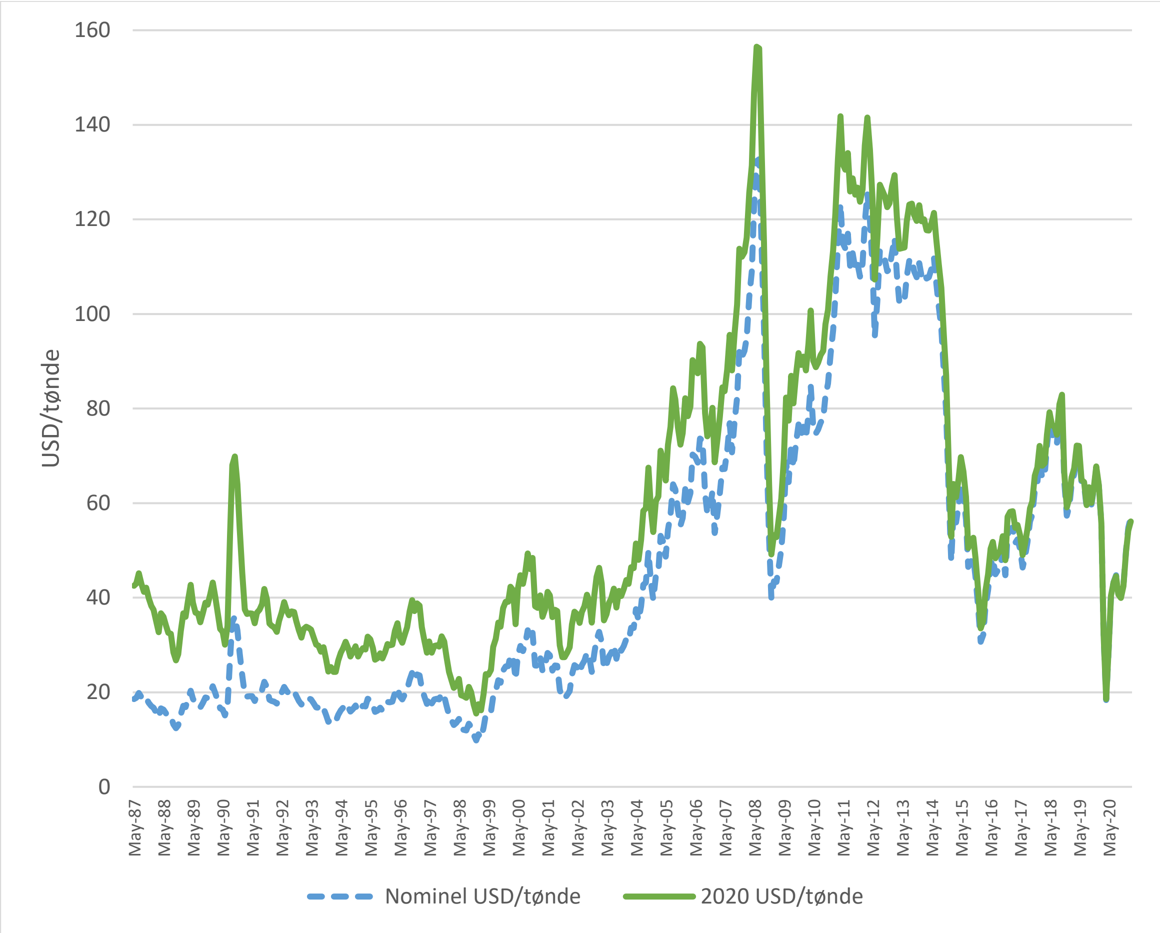
Historisk globalt udbud / efterspørgsel og priser
I det sidste halve århundrede er efterspørgslen efter olie vokset markant, fra ca. 100 EJ (knap 2.400 millioner tons) i 1971 til over 187 EJ (4.475 Mt) i 2019. Med undtagelse af enkelte midlertidige fald som følge af oliekriser i 1980erne og finanskrisen i 2008 og 2009, er den globale efterspørgsel efter olie vokset støt de seneste 50 år. Udviklingen i den globale olieproduktion ses i Figur 2.



Figur 2: Udvikling i olieproduktion efter region fra 1971 til 2019 i millioner af tønder om dagen. (BP, 2020c)

Mens olieefterspørgslen historisk er vokset forholdsvist stabilt, kan det samme ikke siges om udviklingen i olieprisen. I Figur 3 ses udviklingen i Brent-olieprisen (månedsgennemsnit) siden 1987 i nominelle og faste priser.

Fra 1987 til begyndelsen af 2000'erne var den månedlige oliepris i gennemsnit ca. $34 pr. tønde. Prisbilledet ændrede sig i 2003, da den første fase af Irak-krigen startede, og oliepriserne steg markant indtil midten af 2008 (toppede på over $150), hvorefter finanskrisen slog igennem med et kraftigt fald i efterspørgslen og efterfølgende prisfald til under en tredjedel af prisspidsen fra december samme år.



Figur 3: Historiske (1987-2021) råoliepriser (Brent) som månedsgennemsnit i USD/tønde. Nominel (blåstribet linje) og faste priser (2020 USD) (grøn fuldt optrukken linje. (EIA, 2021a). *Bemærk, at prisen for februar 2021 er baseret på første 3 uger.*

Priserne var kun under $60 i et par måneder, før de igen steg markant. Fra oktober 2010 førte dette til en periode på over fire år med gennemsnitlige månedlige priser på over $100 / tønde (og ofte i intervallet 120-140). I løbet af denne tid var vurderingen blandt nogle olie-eksperter og kommentatorer, at oliepriserne sandsynligvis ikke ville falde under $100 / tønde i et årti eller mere (Khrennikova, 2013), mens den generelle konsensus forudsagde oliepriser mellem $80-90 / tønde.

I 2014 begyndte det globale udbud af olie imidlertid at overstige efterspørgslen, og priserne faldt derfor igen kraftigt. En af hovedårsagerne til dette var 'revolutionen' indenfor udvinding af olie og skifergas i USA. Her gav nye frackingteknologier mulighed for en hurtigt stigende olie- og gasproduktion.

Siden starten af 2015 har prisen på Brent-råolie i gennemsnit ligget omkring $57/tønde med korte perioder med gennemsnitlige månedlige priser over $75 / tønde eller under $40 / tønde. I skrivende stund (foråret 2021) var Brent-olieprisen ca. $62 / tønde.

Internationale politikker for olieefterforskning

Med udgangspunkt i ønsket om grøn omstilling, har der de senere år været stigende opmærksomhed også på finansieringen af fossile brændsler. De store energiselskaber diversificerer i stigende grad deres portefølje (se afsnit 7.2). Hertil kommer, at finanssektoren står overfor øget offentlig opmærksomhed på dens rolle omkring finansiering af fossil teknologi.

En række finansielle institutioner har således offentliggjort erklæringer, der begrænser deres engagement i fossile projekter. Nogle af disse institutioner (som inkluderer USA's fem største banker) har henvist specifikt til efterforskning og udvikling af arktisk olie og gas (Oil World, 2020). Imidlertid er det stadig usikkert, i hvilket omfang den faktiske finansiering af arktisk olie- og gasaktivitet vil blive påvirket. Hertil kommer usikkerhed om effekten af den nyligt udmeldte ændrede regulering i Grønland. Historien viser i hvert fald, at det også efter Parisaftalen fra 2015 har været muligt at finansiere olieefterforskning.

Danmark er ikke en stor olienation, men er dog et af de få europæiske lande, der stadig er nettoeksportør af olie og gas. Det var derfor bemærkelsesværdigt, da den danske regering og et flertal i Folketinget i december 2020 annoncerede 2050 som en slutdato for olie- og gasproduktion i Nordsøen samt annoncerede en annullering af 8. og alle fremtidige udbudsrunder for olie- og gaslicenser.

Debatten om grøn omstilling og debatten om energiselskabernes rolle er kompleks. Energiselskaber kan have vidt forskellige strategier omkring fossile brændsler. For eksempel fortsætter nogle olieselskaber i vid udstrækning med "Business as Usual" og fastholder fokus på kerneforretningen (fx ExxonMobil), mens andre som British Petroleum (BP), Total og Shell signalerer strategisk skifte. Det er dog usikkert, om disse signaler reelt betyder et hurtig skift væk fra fossile brændsler og over til vedvarende energi. Under alle omstændigheder ses det, at nogle af de største olieselskaber nu diversificerer ved at inkludere vedvarende energi i porteføljen. Denne diversificering signalerer også, at de er optaget af miljø- og klima, og giver mulighed for at "re-brande" sig selv som energiselskaber mere end olie- og gasselskaber.

Fremskrivning af oliepriser på verdensmarkedet
Historien viser, at det er vanskeligt og særdeles usikkert at fremskrive oliepriserne. Der er mange underliggende og usikre antagelser, der påvirker billedet. Forskellige aktører, der anvender forskellige metoder og antagelser, kan derfor nå frem til ret forskellige resultater.

En af de mest anerkendte institutioner, der modellerer og offentliggør udviklingen i oliemarkedet, er International Energy Agency (IEA). IEA's flagskibspublikation er den årlige World Energy Outlook (WEO). WEO indeholder centrale scenarier for energisektorens udvikling, hvor der i hvert scenarie er beregnet prisudviklingen i energimarkederne.

I WEO 2020 er der vist tre hovedscenarier samt et fjerde supplerende scenarie:

- Stated Policies Scenario (STEPS)
- Delayed Recovery Scenario (DRS)
- Sustainable Development Scenario (SDS)
- Net Zero Emissions by 2050 case (NZE2050)

Til denne analyserapport for Grønlands Energiministerium, er der søgt udarbejdet en central fremskrivning af råolieprisen (Brent) på verdensmarkedet. Fremskrivningen er baseret på fire elementer:

- En gennemgang af centrale kilder der udarbejder prisfremskrivninger.
- En særlig evaluering af den mest centrale kilde (IEA) og deres track record med hensyn til præcision i fremskrivningerne.
- En sektor-for-sektor vurdering af det mest sandsynlige fremtidsscenarie, og anvendelse af et vægtet prisgennemsnit baseret på dette scenarie.
- Hovedantagelsen om, at der er en stigende international konsensus og politisk vilje til at nå netto-nul-emissionsmål.[2]

Der kan argumenteres for, at COVID-19 har øget usikkerheden omkring oliemarkedet i de næste 5-10 år, og eventuelt har udskudt behovet for ny efterforskning. Men da oliefund i Grønland sandsynligvis ikke er i produktion før 2030, forventes COVID-19's betydning ikke at være relevant i analysen.

[2] Senest blev dette understreget af Kina, der planlægger CO2-neutralitet inden 2060, og af Biden-administrationen der har udmeldt at USA sigter mod CO2 neutralitet i 2050.

WEO udarbejder prisfremskrivninger til 2040. Da der i business-case analyserne er behov for prisfremskrivninger helt frem til 2065, var det nødvendigt at forlænge WEO's prisprognoser.

Den valgte metode omfatter udvikling af tre prisscenarier:

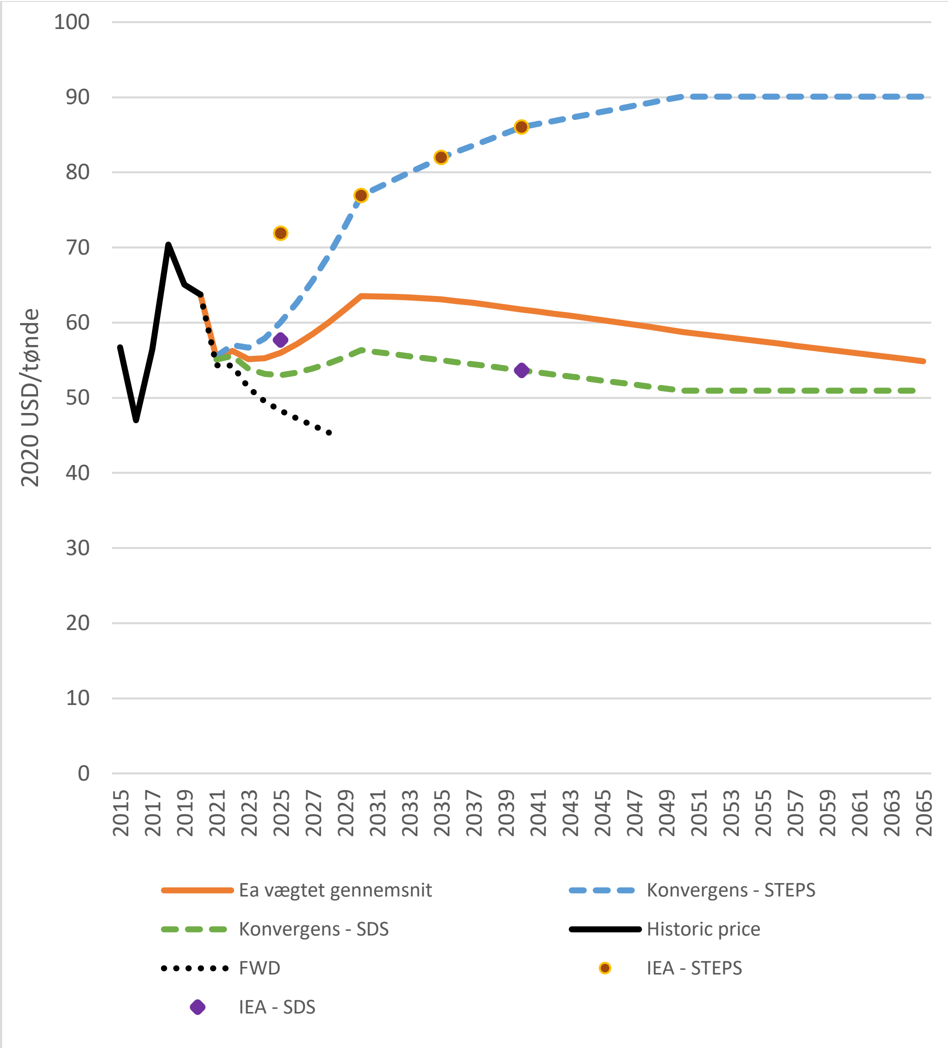
- **STEPS-konvergence:** en kombination af forwardpriser på kort sigt og STEPS-langsigtede priser indtil 2040.
- **SDS-konvergence:** en kombination af forwardpriser på kort sigt og SDS-langsigtede priser.
- **Ea vægtet gennemsnit:** Det centrale prisscenario, det er en kombination af de to ovennævnte scenarier. SDS's vægtning stiger fra 50% i 2020 til 90% i 2065.

Nedenstående tabel opsummerer de forudsætninger, der er anvendt i de tre olieprisscenarier:

	2021-2030	2030-2040	2040-2050	2050-2065
STEPS - konvergence ($STEPS_{con}$)	2021: 90% vægt på forwards 2030: 100% vægt på STEPS langsigtede priser.	100% baseret på STEPS (prispunkter i 2030, 2035, 2040)	Indlagt prisvækst på 50% af væksten I perioden 2030 - 2040.	Fastholde 2050 pris
SDS - konvergence (SDS_{con})	2021: 90% vægt på forwards 2030: 100% vægt på SDS langsigtede priser.	100% baseret på SDS (prispunkter i 2030, 2035, 2040)	Fortsætte tendensen I perioden 2030 - 2040.	Fastholde 2050 pris
Ea vægtet gennemsnit	**50% vægt på $STEPS_{con}$ i 2020, faldende til 35% i 2030**	**35% vægt på $STEPS_{con}$ i 2030, faldende til 25% i 2040**	**25% vægt på $STEPS_{con}$ i 2040, faldende til 20% i 2035**	**20% vægt på $STEPS_{con}$ i 2050, faldende til 10% i 2065**

Tabel 1: Forudsætninger i de tre olieprisscenarier

De resulterende prisscenarier ses i Figur 4.



Figur 4: Tre olieprisscenarier. Ea vægtet gennemsnit er en kombination af de to øvrige scenarier, hvor SDS-vægtning stiger fra 50% i 2020 til 90% i 2065.

Økonomisk vurdering af olieudvinding i Grønland

Den grønlandske regerings skattemodel

Tiltrækning af investeringer til olieefterforskning i Grønland udfordres af flere faktorer, især det at Grønland er en grænseregion med et barskt klima. Derfor besluttede Naalakkersuisut at indføre en ny skattemodel i oliestrategien for Grønland 2020-24.

Nedenstående tabel viser den nuværende og tidligere skattemodel, hvor den effektive sats er baseret på en oliepris på 80 USD / tønde. En lavere oliepris vil reducere den samlede regeringsoptagelse i procent af omsætningen, mens en højere oliepris vil øge regeringsoptagelsen, da den vil udløse en højere overskudsafgift/overskudsroyalty.

	Tidligere model (før 2020)		Ny model for 2020-24	
	Nominel sats	**Effektiv sats***	**Nominel sats**	**Effektiv sats***
Omsætningsroyalty	2,5%	5,5%	0 %	0%
Overskudsroyalty	7,5/17,5/30%	12,9%	3,75/8,75/15%	7,2%
Selskabsskat	25/36%	29,4%	25/36%	33,4%
Selvstyrets medejerskab	6,25%	3,6%	0%	0%
Selvstyrets samlede direkte indtjening fra råstoffer		**51,3%**		**40,6%**

*Tabel 2: Sammenligning af nuværende og tidligere skattemodel i Grønland. * Bemærk, den effektive kurs beregnes ud fra et scenarie med en råoliepris på 80 USD/tønde. Kilde: Naalakkersuisut, 2020, Getting Greenland back on track with oil, Nuuk.*

Den nuværende (nye) skattemodel giver investorer en større sikkerhed sammenlignet med den tidligere model, især fordi investorer kun betaler skat og royalties i år, hvor virksomheden generer overskud. Endvidere er skatten beskeden indtil overskuddet overstiger en vis tærskel. Dette betyder også, at hvis oliepriserne er lave, får Grønland ingen eller meget beskedne skatteindtægter fra olieudvinding.

Potentielle udfordringer for investeringer i olie og gas i Grønland

Gennem årene har Grønland kunnet tiltrække interesse i efterforskning og udvikling af sine olie- og gasressourcer. Siden 1970'erne har adskillige større, uafhængige (IOC'er) og nationale olie- og gasselskaber (NOC'er) givet sig i kast med efterforskning, indtil videre dog uden kommerciel succes.

Flere stimer af interessetilkendegivelser er efterfulgt af opgivelse eller udsættelse af indsatsen. I 2015 - midt i et fald i oliepriserne - leverede DONG Energy (nu Ørsted), GDF Suez og Statoil (nu Equinor) deres licenser tilbage (Reuters, 2015). Samtidig annoncerede Shell, Mærsk og Cairn Energy en midlertidig udsættelse af yderligere efterforskning i Grønland (Kalaallit Nunaata Radioa, 2015). Men allerede før olieprisfaldet i 2015 havde ExxonMobil afstået fra videre aktivitet (Børsen, 2013).

Hvis ressourcerne er til stede som antaget, og da de lovgivningsmæssige rammer stort set vurderes tilfredsstillende, må andre forhold have været udslagsgivende. En kombination af flere faktorer kan muligvis forklare den mindre efterforskningsinteresse i Grønland sammenlignet med andre tilsvarende arktiske områder:

- Grønlands begrænsede infrastruktur
- Transportudfordringer, især i vintermånederne. Dette øger omkostningsniveauet.
- Usikkerhed om efterforsknings-, udviklings- og produktionsomkostninger
- Begrænset adgang til faglært og specialuddannet arbejdskraft
- Risiko for dårligt omdømme såfremt et (usandsynligt) alvorligt miljøudslip alligevel forekommer.

Grønland vurderes til at have betydelige uudnyttede olie- og gasressourcer, men har ikke opbygget en egentlig produktion, og der kan gå lang tid mellem opdagelse og produktion i kommerciel skala. Tidligere erfaring i Arktis (f.eks. Norge, Rusland, Alaska) har vist, at det i gennemsnit tager ti år fra afsluttet efterforskning til kommerciel produktion. Med andre ord kunne et vellykket fund der sker nu (2021),ført forventes at komme i drift tidligt i 2030'erne.

Med udgangspunkt i ovenstående udfordringer kan der argumenteres for, at det allerede er for sent for Grønland at blive olie- og gasproducent. Især i lyset af, at den grønne omstilling udgør en risiko for, at en fossil investering nu er forældet allerede om 10-20 år på grund af hurtig overgang til vedvarende energi. Alaska, Rusland og Norge har høstet ”First Mover” fordelen i det arktiske område, idet disse lande er veletablerede olie- og gasprovinser efter årtier med kontinuerlig interesse fra olie- og gasselskaberne og en vedholdende udvikling af attraktive rammebetingelser.

I de senere år med lave oliepriser (og nu også COVID) har investorernes interesse været i mere udbygning af eksisterende produktion med sikrere afkast, sammenlignet med opstart af ny produktion som f.eks. i Grønland. Set i lyset af de forskellige risici, vil nogle investorer muligvis foretrække at øge tilstedeværelsen i kendte områder og helt se bort fra Arktis.

Når alt kommer til alt, kan der være langt mellem potentielle investorer i den grønlandske olie- og gassektor, men de findes sandsynligvis. En investortype kunne karakteriseres ved en højere risikoprofil. En sådan investor kunne måske have en mere kortsigtet strategi, med fokus på efterforskning og fund med henblik på videresalg. Det er ikke ualmindeligt, at nogle virksomheder fokuserer på efterforskning snarere end på produktion.

Alternativt kan landet tiltrække investorer, der ser muligheden for at komme ind i Grønland som en strategisk - muligvis geopolitisk - andel i et af verdens grænseområder. En kombination af kapital og interesse fra nationale virksomheder (muligvis fra hurtigt voksende økonomier som Kina eller Indien) i samarbejde med den tekniske og forretningsmæssige ekspertise fra lande med solid arktisk erfaring (f.eks. Russiske virksomheder) kunne finde det attraktivt at investere i Grønland. Sådanne investorer vil have et langsigtet strategisk perspektiv.

Grøn omstilling og klimaforandringer
Som tidligere nævnt udgør den stigende fokus på klimaforandringer en særlig risiko for virksomheder engageret i produktion af fossile brændsler. Meget tyder på, at olie- og gasproducenter kæmper for at sikre balancen mellem at fastholde eksisterende værdier, investere for fremtiden og at håndtere Public Relations i forhold til klimadagsordenen.

Potentielle strategier for at tiltrække investeringer
Et vigtigt element i vurderingen af investorers interesse i Grønlands olie- og gasressourcer er de komparative fordele sammenlignet med andre arktiske områder, der ligger i Naarlakkersuisut´s beskatningsmodel (take-struktur). En attraktiv beskatningsmodel er nødvendig, men ikke tilstrækkelig, da der er andre etablerede regioner i Arktis, der tilbyder bedre betingelser med hensyn til vigtige elementer såsom opbygget infrastruktur, erfaringer, og den samlede geologiske viden om undergrunden.

Kan Grønlands olieressourcer modregnes ved CO2-kompensation?
CO2-kompensationer er en markedsmekanisme, hvor virksomheder, der udleder CO2 og andre drivhusgasser, kompenserer disse emissioner med reduktioner, der sker andre steder. Herved kan *aktivitetens Carbon-footprint* indirekte reduceres.

I olie- og gasindustrien er der et nylig (sandsynligvis det første) eksempel på, at en råolie-kulstof-offset-levering finder sted mellem en opstrøms producent (Oxy) i Perm-bassinet (USA) og en stor industriel forbruger i Indien (Reliance Industries) (Veazey, 2021).

Nødvendig Intern Rente (IRR) til projekter i Grønland
Som gennemsnit angiver en række finansielle kilder, at olie- og gasindustriprojekter i disse år forrentes med en gennemsnitlig intern rente på 15-20%. Tidligere projekter vurderedes at have et mere moderat afkast på ca. 10%, og der kan således være tale om en stramning af forrentningskravet til nye projekter.

Potentiel værdi af oliereserverne

På baggrund af ovenstående reserveestimater og olieprisscenarier er den potentielle værdi af Grønlands oliereserver vurderet. Vurderingen er afgrænset til reserver, der kan udvindes inden for de næste 30-40 år, og er tillige afgrænset til offshore olieudvinding, altså ikke gas. Gaseksport kræver etablering af LNG-terminaler, hvilket ikke er analyseret videre i denne rapport.

Input og metode

Nunaoil A/S har leveret væsentlige input i form af CAPEX- og OPEX-proxytal for hvert af de potentielle projekter, der indgår i analysen, og ved kommentering af Eas valg af de tidsperioder for projektforløb der indgår i beregningerne. I Sydvestgrønland antages det, at der teoretisk kan igangsættes tre projekter de kommende ti år, imens det på grund af sværere isforhold i Nordvestgrønland antages at ét større projekt er mere realistisk. (Se Tabel 1).

parameter	enhed	SV1	**SV2**	**SV3**	**NV**
Felt- og reservoiregenskaber					
Feltstørrelse (mængde der kan udvindes)	mboe	250	250	250	650
Vanddybde	Meter	0 - 200	0 - 200	200 - 1500	0 - 200
Reservoirdybde	Meter	2000	3000	4000	3000
Start- og restaureringsomkostninger					
Undersøgelse	mio. USD	$400	$520	$800	$750
CAPEX	mio. USD	$5.800	$6.200	$6.600	$16.800
Restaurering	mio. USD	$600	$650	$700	$1.200
Driftsomkostninger					
OPEX	USD/boe	$15	$17	$20	$25
Transport	USD/boe	$3	$3	$3	$6
Tidsperioder					
Opstartsår	år	2022	2025	2028	2025
Forberedelse	år	3	3	3	3
Undersøgelse	år	6	6	6	7
Byggeri	år	6	6	6	8
Produktion	år	20	20	20	20
Restaurering	år	3	3	3	4

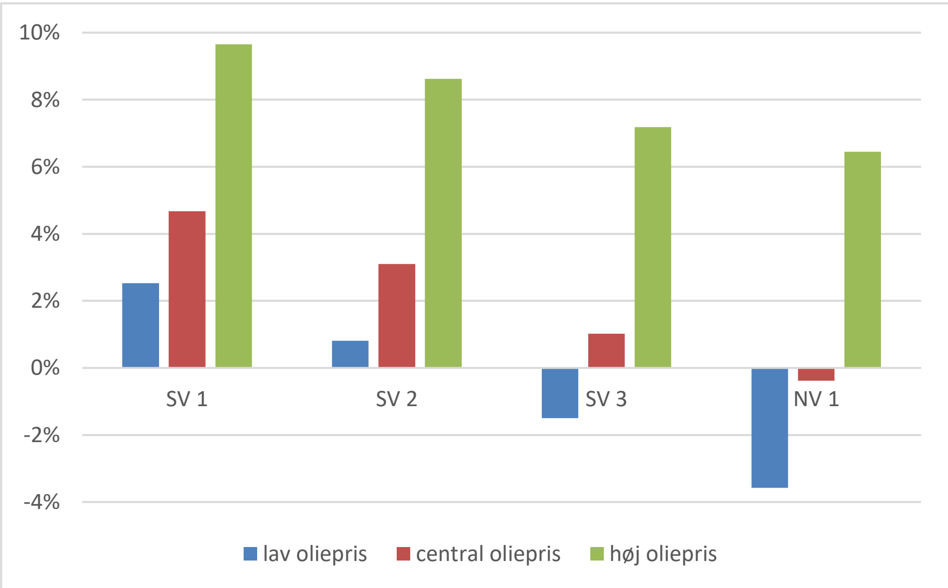
Tabel 3: Standardantagelser anvendt i IRR- og NPV-analyse af hypotetiske oliefelter i Sydvest- og Nordvestgrønland.

Den årlige olieproduktion fra de fire projekter vist i tabellen antages at følge en standardiseret olieproduktionsprofil, dvs. en stejl opstartsfase, efterfulgt af en periode med maksimal produktion og afsluttende med udfasning og produktionsfald.

Beregning af Grønlands afkast af projekterne
Det er vurderet og beskrevet ovenfor, at olieselskaber som hovedregel kræver en intern forrentning et stykke over 10% ved investeringer i nye områder.

For hvert af de analyserede projekter er der udarbejdet intern rente for olieselskabet, cashflow i projektperioden samt nuværdien af afkastet (Selvstyrets samlede direkte indtjening fra råstoffer, eller "take") til Grønland. Nuværdien er beregnet med en statslig diskonteringsrente på 3%, og take strukturen er forsimplet tolket sådan, at der først genereres take når det enkelte projekt når økonomisk break-even. Tidspunktet for break-even er beregnet som det tidspunkt, hvor akkumulerede indtægter overstiger akkumulerede omkostninger (excl. forrentning af kapital). Efter dette tidspunkt betales 33,4% af overskuddet som afkast til Grønland. Bemærk at dette er en forsimpling af den gældende take-struktur.

Intern rente (IRR) samt nuværdi af take-afkast til Grønland (NPV)
Nedenstående figur viser intern rente[3] for alle fire projekter, i de tre olieprisscenarier, der er beskrevet tidligere.



Figur 5: Internt rente (IRR) for fire hypotetiske olieprojekter i Grønland udregnet for tre forskellige olieprisscenarier.

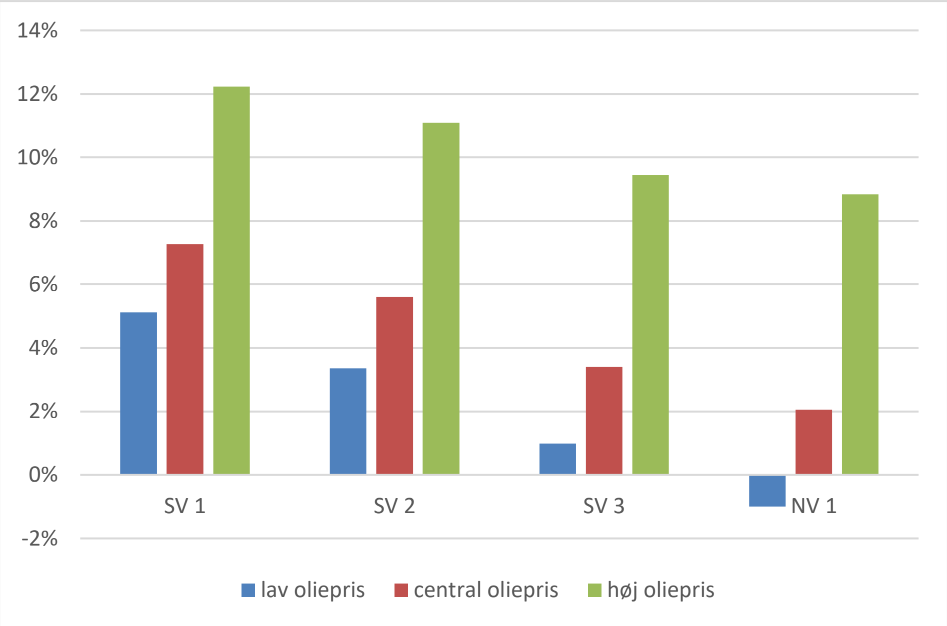
[3] Intern rente er beregnet uden hensyntagen til beskatning.

Som det fremgår af figuren, overstiger den beregnede IRR ikke 10% for nogen af projekterne, selv i et scenarie, hvor olieprisen i gennemsnit er 88 USD pr. tønde i olieproduktionsårene. Hvis olieselskabets IRR-niveau sænkes til 7,5%, bliver de første to projekter ud for Grønlands sydvestlige kyst rentable, men kun i scenariet med høje oliepriser.

Med det sænkede IRR-niveau på 7,5%, og med højprisscenariet som grundlag, er nutidsværdien af afkastet til Grønland beregnet til 1,66 mia. USD for SV 1-projektet og 1,40 mia. USD for SW 2-projektet.

Følsomhed med lavere CAPEX

Med grundforudsætningerne anses det som usandsynligt at et olieselskab investerer i olieproduktion i Grønland. Som følsomhed er konsekvensen af 25% lavere CAPEX analyseret, og resultatet for den interne rente er vist i Figur 6.



Figur 6: Internt rente (IRR) for fire hypotetiske olieprojekter i Grønland med tre forskellige olieprisscenarier under forudsætning af lavere CAPEX.

I lav-CAPEX-følsomheden og i højprisscenariet genererer de to første hypotetiske projekter ud for den sydvestlige kyst af Grønland en IRR, der overstiger det antagende minimum på 10%.

Nedenstående tabel viser den potentielle grønlandske NPV for alle fire projekter under forudsætning af *både* lav CAPEX *og* høje oliepriser.

	Projekt-IRR	Grønlandsk NPV (mia. USD)
SW 1	12.2%	$1,9
SW 2	11.1%	$1,6
SW 3	9.5%	$1,3
NW 1	8.8%	$3,1
Samlet for alle projekter		$8,0
I alt for projekter med min. 10% IRR		**$3,6**

Tabel 4: Standard, høje og lave CAPEX-værdier anvendt i IRR-analysen af hypotetiske oliefelter i Sydvest- og Nordvestgrønland.

Konklusioner vedrørende IRR og NPV

Med grundforudsætningerne vurderes det ikke sandsynligt, at et olieselskab vil finde det økonomisk attraktivt at foretage olieinvesteringer i de hypotetiske projekter, der er beskrevet i den aktuelle analyse.

Såfremt et olieselskab i sine interne analyser anvender oliepriser, der i gennemsnit frem mod ca. 2060 er ca. 90 USD/tønde (i faste priser), og såfremt CAPEX kan reduceres med ca. 25% sammenlignet med grundforudsætningerne, så vurderes det muligt at finde interesse for olieprojekter i Grønland. I en sådan situation er nutidsværdien af en beskatning på 33,4% til Grønland beregnet til ca. 3,6 mia. USD.

Det skal understreges, at der er væsentlige usikkerheder omkring forudsætningerne i analysen, især omkring olieprisens udvikling og olieselskabernes forrentningskrav.

Konklusioner og SWOT-analyse

De to centrale spørgsmål, der er stillet til denne analyse, er:

- Hvad er sandsynligheden for, at Grønland kan blive et olieeksportland i fremtiden?
- Hvad er det økonomiske potentiale og miljøudfordringerne?

Baseret på en vurdering af potentielle investorers afkastkrav, og baseret på en scenariefremskrivning af olieprіserne på verdensmarkedet, indikerer analysen at det ikke er sandsynligt, at Grønland kan blive et olieeksportland de kommende årtier. En stærkt medvirkende årsag til konklusionen er usikkerhed om omkostningsniveauet i kombination med Grønlands sårbare natur.

Man kunne også stille et tredje spørgsmål, nemlig:

- Hvad er konsekvenserne af, at Grønland opretholder en ambitiøs og stødende oliestrategi?

Med udgangspunkt i at Grønland råder over betydelige uudnyttede olie- og gasressourcer, er det relevant at vurdere fordele og ulemper ved at holde døren til potentielle investeringer åben. Hvorvidt en offensiv oliestrategi skal opretholdes eller ej, er en politisk beslutning, som folk i Grønland og deres valgte embedsmænd skal foretage. For at understøtte en sådan beslutningsproces vises nedenstående resultatet af en indledende SWOT-analyse.

Styrker

- Det holder en mulighed åben for Grønland. Oliepriserne har historisk været vanskelige at forudsige, og hvis der igen opstår høje priser, kan Grønland muligvis være i stand til at tiltrække interesse.
- Grønland kan ses som en attraktiv strategisk samarbejdspartner for USA, Kina, Rusland og andre.
- Tid, kræfter og finansiering brugt på at udvikle den nuværende vidensbase går ikke tabt.

Svagheder

- Hvis interessen fortsat er lav, kan det være en meningsløs indsats, der tager fokus og finansiering fra andre strategiske områder.
- Fortsat at promovere muligheden på trods af manglende interesse kan blive opfattet som useriøst.

Muligheder

- Sikrer, at mulighederne for arbejdspladser og nye indkomstmuligheder ikke går tabt, selvom chancerne for stor eksport af olie vurderes små.

Trusler

- Grønland har en mulighed for at blive branded som en ”miljøvenlig stat”. En ambitiøs oliestrategi kan bringe dette ”brand” i fare, både internt i Grønland og i udlandet.
- Hvis der rent faktisk påbegyndes en udvikling som olie- gasproducent, er der en risiko for miljømæssige skadevirkninger. Det kan have negativ effekt på fiskeri, jagt og turisme. Risikoen for et større olieudslip er lav, men virkningerne kan være katastrofale.

2 Report summary

Introduction

The purpose of this report is to provide political decision makers with insights into the economic potential and likelihood of Greenland becoming an oil exporting country in the years to come, as well as the potential environmental implications of such a development.

The point of departure of the report is existing analyses and reports from Greenland together with international sources. Based upon the information presented, the primary research issue to be addressed is: What is the likelihood of Greenland can become an oil exporting country in the future? And what are the economic potential and environmental challenges?

The majority of inputs to the report were provided by Nunaoil A/S (the national oil company of Greenland), and various Government of Greenland departments. Ea Energy Analyses was responsible for compiling and editing these inputs into the current report. All analyses and conclusions undertaken on the basis of the provided inputs are those of Ea Energy Analyses, and are not the official stance of any of the Government of Greenland departments.

Historic overview of Oil exploration in Greenland and the Arctic

The first oil exploration efforts in Greenland began in the early 1970s and picked up speed in the mid-1970s. This was a response to the oil crisis in the early 1970s, as well as the discovery of the Prudhoe Bay oil field in Alaska in the 1960s.

From its onset, activities related to hydrocarbon exploration and exploitation in Greenland were administered by the Ministry of Greenland in Copenhagen, but in 1979 Greenland attained a Home Rule Government. From that point, decisions relating to hydrocarbon exploration and exploitation were moved to a Joint Committee of politicians from their respective parliaments. During the period between 1979 and 1999, the administrative tasks were dealt with from an office in Copenhagen (The Mineral Administration for Greenland, MRA; Christiansen, 2011), but in 1999 the administration moved to Nuuk under the Bureau of Minerals and Petroleum (BMP; Christiansen, 2011).

In 1974, six groups lead respectively by Amoco, ARCO, Chevron, Mobil, Total and Ultramar, were rewarded 13 offshore exploration licenses covering an area of 19,082 km^2 off the west coast of Greenland (Christiansen, 2011). During the following years, five exploration wells were drilled, but of the five wells, only the first, the Kangâmiut-1 well, encountered hydrocarbons in the form of gas, but due to technical issues, the well never flowed. By early 1979 all licenses were released, and offshore exploration ceased until 1996.

During the 1980s, exploration only took place onshore on Jameson Land, where ARCO, Arktisk Minekompagni A/S and Nunaoil A/S signed a concession agreement in January of 1985 for an area of roughly 10,000 km^2 and acquired a total of 1,798 km of 2D seismic data during the period of 1985-1989. By the end of 1990, the license was relinquished, mainly because of a drop in oil prices and what was interpreted to be unfavourable geological settings for doing a commercial discovery.

As part of an exploration strategy formulated in the early 1990s, a new licensing round opened in 1992. However, as no applications were received it was decided to turn to an open-door policy for the offshore areas south of 70°30’N in West Greenland.

In 1996, outside of the normal licensing round procedure, Statoil and its partners (Phillips, DONG and NUNAOIL) were granted a license in southwest Greenland. However, drilling results were disappointing, and by the end of 2001, the consortium released the license.

A strategic oil seep sampling program onshore Disko and Nuussuaq in the early 1990s created some industry interest. This resulted in an application for a prospecting license from GrønArctic in 1994, and an exploration and production license the following year. Initial drilled core holes provided promising results, but a later well was less promising, and GrønArctic relinquished its license in mid-1998 (Christiansen, 2011).

In late 1989 negotiations were finalised, and in what became known as the KANUMAS (Kalaallit Nunaat Marine Seismic) project, a prospecting license was issued to a consortium of six major companies: BP, Exxon, Japan National Oil Company, Shell, Statoil and Texaco, with NUNAOIL participating as a carried partner and operator for the consortium (Christiansen, 2011).

During the 2000s, a number of licensing rounds opened up in the offshore areas of West Greenland. As a result of aggressive seismic data acquisition and the many licensing rounds the Atammik license (3,985 km^2) in southwest Greenland was granted in 2002 to EnCana followed by a second granting to EnCana of the Lady Franklin license (2897 km^2) in 2005 (Christiansen, 2011).

For Disko West, the licensing round was two-phased, with an initial phase of eight predefined blocks west of Disko and a later second phase under an open-door award system. The predefined blocks had sizes ranging from more than 10,000 km^2 to close to 14,000 km^2 and during the first phase seven of the eight blocks were awarded during 2007 and 2008 to joint ventures consisting of a combination of oil majors (e.g., Chevron and ExxonMobil) and medium sized companies (Cairn, DONG, Husky and PA Resources) (Christiansen, 2011). Later in 2008 and early 2009, Cairn applied for four large licenses (each in excess of 10,000 km^2) via the open-door system off Cape Farewell and farmed-in on both of the EnCana licenses (Atammik and Lady Franklin) (Christiansen, 2011).

In 2008, Husky acquired the first 3D seismic surveys on the Greenland shelf in their two license blocks (Kangerluk and Ikermiut - 2,171 km^2 in total), showing that it was possible to acquire this type of data in iceberg infested areas. Later in 2011 and 2012, 3D seismic acquisition was acquired in even harsher conditions, in the Baffin Bay and Cap Farewell. By 2015 however, all the exploration licenses in Disko West had been relinquished due to difficulties in finding drillable prospects in the challenging volcanic covered license areas.

A new Baffin Bay licensing round in 2010 was a success, with 17 applications from 12 companies and the granting of seven licenses. The applicants consisted of major international companies (e.g., ConocoPhillips, Shell, Statoil) and mid-sized companies (e.g., Cairn Energy, DONG, Faroe Petroleum, Mærsk). In early 2011, seven exploration and production licenses were awarded to five different consortia. By June of 2014, the global price of crude oil plunged, jeopardising the commerciality of prospects in the Baffin Bay licenses and the joint ventures decided to relinquish their licenses by the end of 2015.

At the beginning of 2011, the Greenlandic authorities opened a two-phased licensing round in the Greenland Sea (NE Greenland). The license area consisted of 19 predefined blocks covering a total area of 50,000 km^2 that had been nominated by the KANUMAS group (BP, Exxon, JNOC, Shell, Statoil, Texaco). In the first phase, predefined blocks covering an area of 30,000 km^2 was on offer and reserved for consortiums that included at least one of the KANUMAS companies. By the deadline in December of 2012, four licenses were granted to three consortia. In the second phase, one license was granted, bringing the total the number of licenses in the Greenland Sea to five. The very high costs of data acquisition, the low oil price, and the extremely high costs of drilling and development scenarios meant that the commerciality of prospects in the Greenland Sea was severally hampered, and by the end of 2010s (2018 and 2019), the operators relinquished their licenses.

Greenland's oil and gas activities and estimated hydrocarbon resources
As of February 2021, there were six active prospecting licences and four active exploration and exploitation licences in Greenland. This represents a long and steady decline (see Figure 1) relative to the 2010-2015 period.

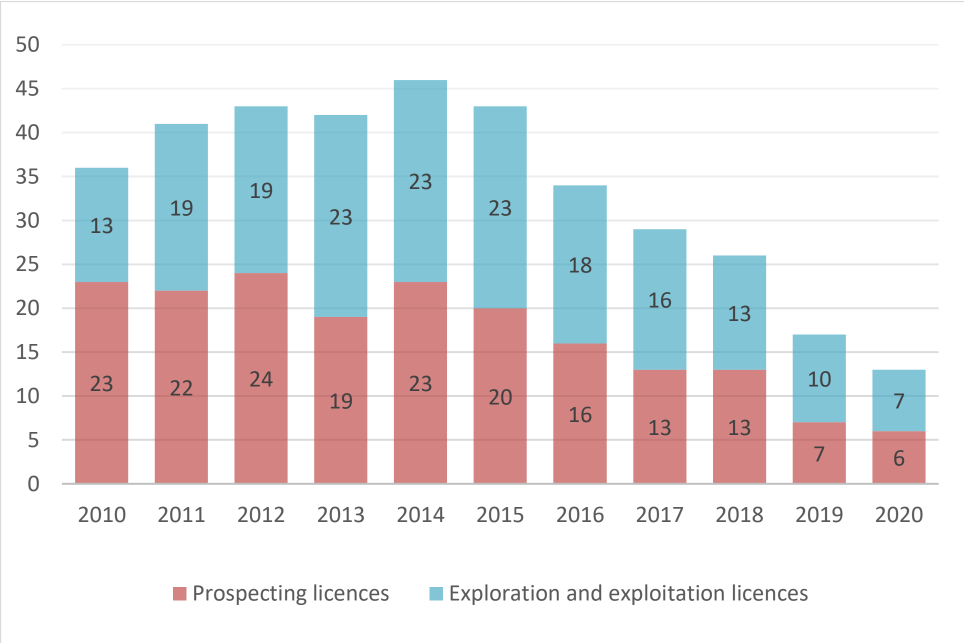


Figure 1: Number of hydrocarbon licences in Greenland. Please note that the number of exploration and exploitation licences include licences under a surrender process.

In 2020, the Government of Greenland launched a new oil and gas strategy covering the period 2020-2024. The strategy includes a plan for the opening of licencing rounds and open-door procedures. The strategy will have a focus on onshore exploration at the Nuussuaq peninsula, where the Government of Greenland has conducted a number of geological studies to outline the oil potential.

The whole of Greenland resource assessment (WOGA) study has now completed a resource assessment for the West Greenland Shelf. The findings indicate a mean case assessment of more than 18 BBOE (billion barrels of oil equivalent) with the most potential in the Baffin Bay assessment unit. A previous USGS resource assessment utilised a different methodology and covered an area roughly 20% larger, but its findings were similar in scale i.e., 17 billion BOE (mean case).

The WOGA assessment for East Greenland Shelf is not yet complete, but a previous USGS assessment suggest that resources here could be almost twice those in West Greenland. The USGS 2007 resource assessment for the East Greenland Shelf is estimated to have a mean undiscovered potential of 31.4 BBOE conventional petroleum resources. The updated resource estimates for the WOGA Northeast Greenland assessment incorporating the most recent data will be ready in the spring of 2021.

Environmental effects of oil exploration and extraction

Situated in the Arctic region, the environment is of great importance for the Government of Greenland. Therefore, all hydrocarbon exploration in Greenland must follow best environmental practices and high international standards in order to protect the environment.

When applying for a license or an activity in Greenland, environmental, nature and climate matters regarding mineral Resource activities are assessed by the Environmental Agency for Mineral Resource Activities (EAMRA).

Arctic and subarctic environments are characterised by low biodiversity, a relatively simple food web that only has a few levels from primary production to top predator, and key species that play an important role in the ecology of the region.

Sea ice and icebergs are important factors in relation to oil and gas activities as it makes operation more complex. Sea ice conditions vary considerably through the years, but the general trend is a decrease in sea ice.
The main environmental impact of hydrocarbon activities is related to noise, release of drilling mud and production water, and the placement of fixed structures.

By far the largest potential environmental impact from oil and gas exploration and exploitation would be from a large oil spill. Major oil spills in relation to oil exploration are most likely to happen as a result from a blowout during an exploration drilling or as spill from tankers. A major oil spill in Greenland would have massive consequences for the environment. Oil spills from oil exploration are very rare and the oil industry has very high safety standards, especially when working in an arctic environment.

The Paris Agreement is a legally binding international treaty on climate change adopted by 196 Parties at COP 21 in Paris, on December 12th, 2015, and entered into force on November 4th, 2016 (IPCC). The goal is to limit global warming to well below 2, preferably to 1.5 degrees Celsius, compared to pre-industrial levels. To achieve this long-term temperature goal, countries aim to reach global peaking of greenhouse gas emissions as soon as possible to achieve a climate neutral world by mid-century. Based on a global oil consumption of app 100 bbl./day in 2019 (EIA), the direct CO_2 emission from burning oil in non- petrochemical sectors can be calculated to 14.4 billion tonnes CO_2, one third of global emissions.

Global oil demand, prices and policies

Since the oil crises of the 1970s, the global demand for oil has increased steadily by an average of 1.5% a year up to the current level of approximately 100 bio bbl/day. Today oil makes up 30% of global primary energy supply, a role that is expected to slowly decrease over the coming years.

Historic global supply/demand and prices

During the last half century, the demand for oil has grown significantly, from roughly 100 EJ (just under 2,400 million tonnes) in 1971, to over 187 EJ (4,475 Mt) in 2019. The development in historic global oil production by region in millions of barrels per day is displayed in Figure 2.

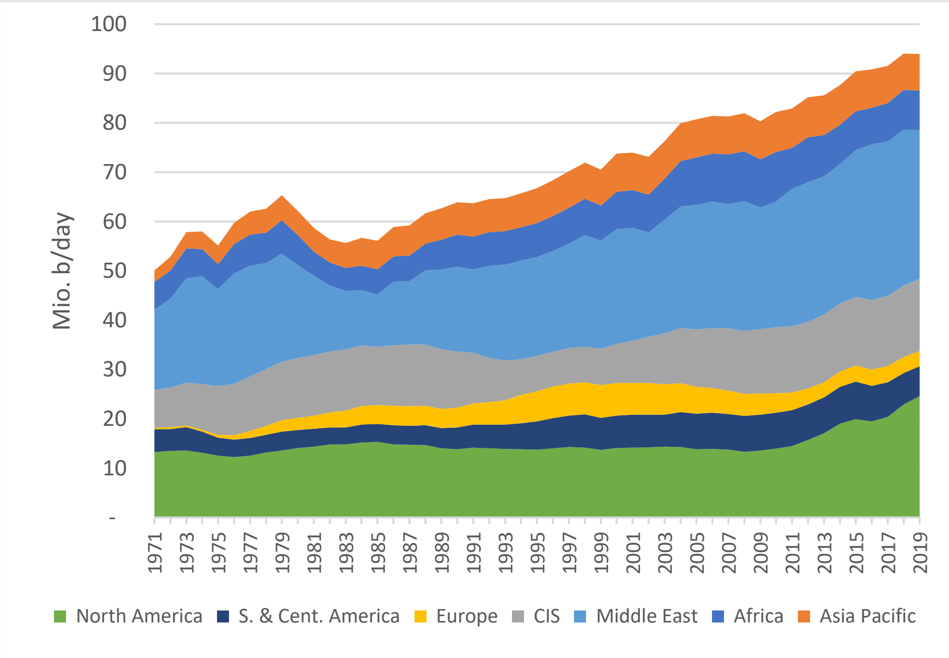


Figure 2: Development in historic oil production by region from 1971 to 2019 in millions of barrels per day. (BP, 2020c)

With the exception of a few drops in the early 1980s, and as a result of the financial crisis in 2008 and 2009, global oil demand has grown steadily over these 50 years.

While the demand for oil has historically grown at a fairly steady rate, the same cannot be said for the development in the price for oil. This is highlighted in Figure 3, which displays the historic monthly Brent oil price per barrel in both nominal, and 2020, USD terms since 1987.

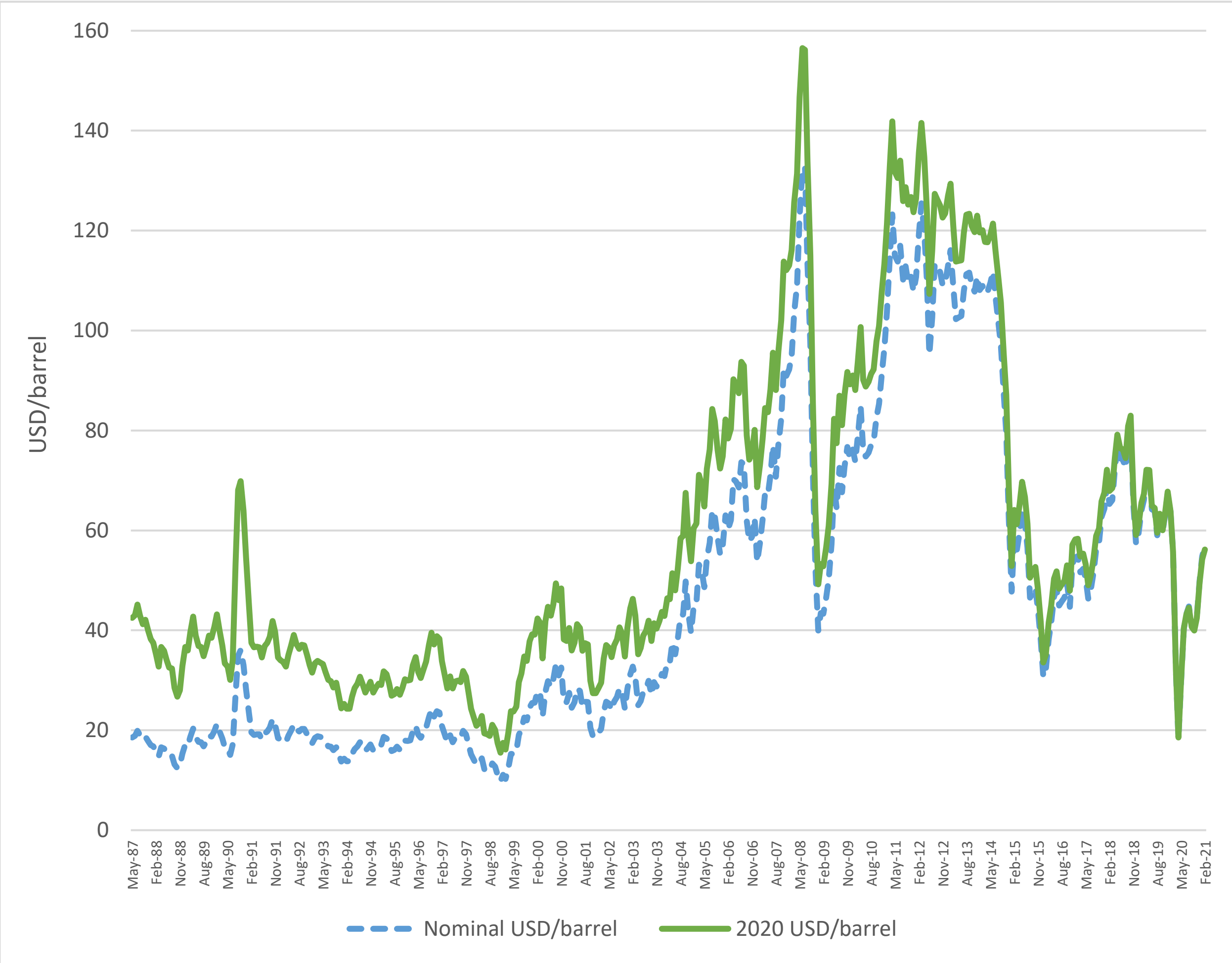


Figure 3: Historic (1987-2021) average monthly price per barrel of brent crude in nominal (blue striped line) and real terms 2020 USD) (green solid line (EIA, 2021a). *Note that the price for February of 2021 is based only on the first 3 weeks.*

From 1987 until the early 2000s, the monthly oil price averaged roughly $34 per barrel, and was usually within +/- $5 of this average. All of this changed in 2003 when the first stage of the Iraq war started, and oil prices increased significantly until the middle of 2008 (peaking at over $150), at which point a sharp decline in oil demand due to the financial crisis resulted in oil prices falling to under a third of their previous high by December of the same year.

Prices were under $60 for only a few months before once again increasing significantly. Starting in October of 2010, this led to a period of over 4 years with average monthly prices over $100/barrel (and often in the $120-140 range). During this time, the feeling amongst some oil experts and commentators was that oil prices were unlikely to fall below $100/barrel for a decade or more (Khrennikova, 2013), while the general consensus indicated oil prices between $80-90/barrel.

In 2014 however, the global supply of oil started to outpace global demand, and as a result, prices fell very sharply. One of the main reasons for this was the oil and shale gas 'revolution' occurring in the United States. Here, new fracking technologies and methods were allowing for largescale and very quick ramping up of oil and gas production.

Since the start of 2015, the price of Brent crude has averaged roughly $57/barrel, with short periods of average monthly prices above $75/barrel or below $40/barrel. At the time of writing (spring of 2021), the Brent oil price was roughly $62/barrel.

Overview of global policies on oil exploration
In recent times, there has been growing attention on the funding of exploration and development of fossil fuels as part of a growing consensus surrounding the necessity of a swift green transition. In addition to major energy companies advocating for an increasing diversification of their portfolio (see section 7.2), the finance industry is also facing renewed scrutiny from the public in their role as financers of climate change.

In this respect, there are several financial institutions that have issued voluntary policy statements limiting their exposure to fossil investments. Some of these institutions (which include the USA's five largest banks) have made specific reference to the exploration and development of Arctic oil and gas (Oil World, 2020). However, the extent to which such industry self-regulations will impact actual financing of Arctic oil and gas activity still is uncertain. In addition, the extent to which the recently approved government regulation will succeed is also uncertain, as there will be pressure from the lenders' side. Nonetheless, evidence shows that after the Paris Agreement was signed in 2015, energy companies have continued to receive financing.

Though not a major oil and production nation, Denmark is one of the few European countries that is a net exporter of oil and gas. Thus, it was noteworthy when in December of 2020, the Danish parliament announced an end-date for oil and gas production in the North Sea of 2050, and the cancellation of the 8th and any future tender rounds for future oil and gas licences.

The ongoing discussion regarding the green transition, and the role that energy companies can play in it is rather complex, as these have widely diverging strategies. For example, some oil companies are largely continuing with business as usual and maintaining their focus on their core competencies (e.g., ExxonMobil), while others such as British Petroleum (BP), Total and Shell are signalling a large strategic shift. However, the extent to which this signalling will mean a substantial and fast-paced shift from fossil fuels to renewables is also uncertain. In any case, there exists ample evidence that some of the major oil companies are diversifying risk exposure by including renewables into their portfolios. In an effort to signal their preoccupation with environmental concerns they are also striving to rebrand themselves as energy – rather than oil and gas – companies. However, some of the very same companies are simultaneously (yet somewhat discreetly) securing their participation in the exploration of oil and gas in a growing effort to secure mid to long-term shareholder value.

Future global supply/demand and prices

Forecasting future energy prices such as oil is a complicated endeavour, with numerous underlying assumptions affecting the forecasted prices. As a result, diverse actors, utilising varying methodologies and assumptions, can arrive at widely diverging results.

One of the primary actors that models future potential energy prices is the International Energy Agency (IEA). The IEA's flagship publication is its annual World Energy Outlook (WEO), which includes a few primary scenarios resulting in future energy prices. The three main scenarios, along with a supplemental 4th scenario, in the 2020 WEO are the:

- Stated Policies Scenario (STEPS)
- Delayed Recovery Scenario (DRS)
- Sustainable Development Scenario (SDS)
- Net Zero Emissions by 2050 case (NZE2050)

Numerous aspects and inputs were analysed in order to arrive at a central price forecast for oil. To summarise, the final price forecasts are based on four elements:

- A review of various price forecasts from a variety of sources

- An evaluation of the IEA's track record to produce price forecasts, as well as the challenges it has faced in forecasting renewables
- A sector-by-sector evaluation of the most likely scenario, and the application of a weighted average based on this approach
- A growing international consensus and political willingness in achieving net-zero emission targets. Most recently this was highlighted by China pledging to be CO_2 neutral by 2060, and the Biden Administration indicating that the USA aims at achieving this target in 2050.

Given the situation the past year, a reflection on the effect of COVID-19 on future prices is also relevant. It could be argued that COVID-19 has increased uncertainty about the oil market for the next 5 -10 years or so, and has, at the very least, delayed the need for new exploration to fill the gap of declining fields. However, as any oil finds in Greenland are unlikely to start producing prior to 2030, COVID-19s direct effects on longer-term oil prices are not expected to be significant.

Finally, and related to the timing of any potential new Greenlandic oil production, any oil fields starting to produce after 2030 are likely to still be producing well after 2040, which is the end date for the WEO price forecasts. It was therefore necessary to extend the price forecasts through to 2065.

The final approach involved producing three price scenarios:

- STEPS convergence: a combination of forward prices in the short term and STEPS long-term prices until 2040.
- SDS convergence: a combination of forward prices in the short term and SDS long-term prices.
- Ea weighted average: The central scenario, it is a combination of the two above scenarios where the SDS' weighting increases from 50% in 2020 to 90% in 2065.

The table below summarises the assumptions utilised in the three oil price scenarios for various periods during the scenario timeframe.

	2021-2030	2030-2040	2040-2050	2040-2050
STEPS - convergence ($STEPS_{con}$)	2021: 90% weighting on forwards 2030: 100% weighting on STEPS long-term price trend	100% based on STEPS long-term price trend (price points in 2030, 2035, 2040)	Applied a growth rate equal to 50% of that from 2030 to 2040.	Maintained 2050 price
SDS - convergence (SDS_{con})	2021: 90% weighting on forwards 2030: 100% weighting on SDS long-term price trend	100% based on STEPS long-term price trend (price points in 2025 & 2040)	Continued trend from 2030 to 2040.	Maintained 2050 price
Ea - weighted average	**50% weighting on $STEPS_{con}$ in 2020, falling to 35% in 2030**	**35% weighting on $STEPS_{con}$ in 2030, falling to 25% in 2040**	**25% weighting on $STEPS_{con}$ in 2040, falling to 20% in 2035**	**20% weighting on $STEPS_{con}$ in 2050, falling to 10% in 2065**

Table 1: Assumptions utilised in the three oil price scenarios

The resulting price scenarios are displayed in Figure 4.

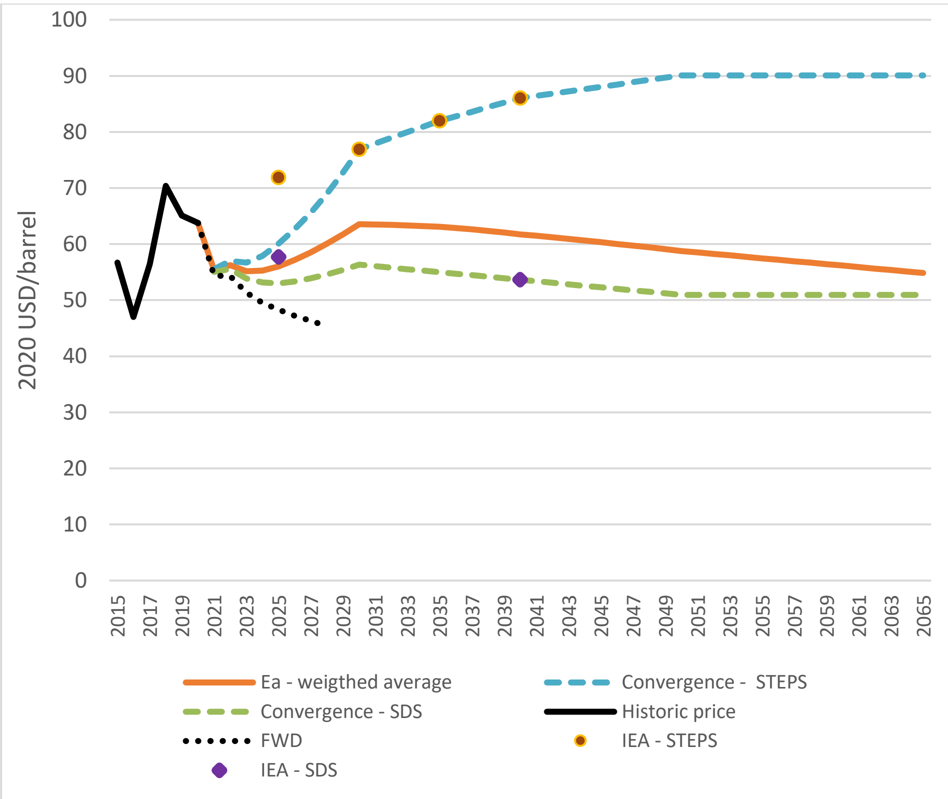


Figure 4: Three future oil price scenarios. STEPS convergence: a combination of forward prices in the short term and STEPS long-term prices until 2040. SDS convergence: a combination of forward prices in the short term and SDS long-term prices. Ea weighted average: a combination of the two above scenarios where the SDS' weighing increases from 50% in 2020 to 90% in 2065.

Economics of oil extraction in Greenland

Government take structure in Greenland

Attracting investments in oil exploration in Greenland is challenged by several factors, the most relevant likely being that Greenland is a frontier region and has a harsh natural climate. Therefore, with a view to make Greenland more attractive to oil companies and stay competitive among other frontier regions, Naalakkersuisut decided to impose a new tax regime, or government take model, in the new oil strategy for Greenland 2020-24.

The table below displays the current and former take structure, with the effective rate being based on an oil price of 80 USD/barrel. A lower oil price will reduce the total government take as a percentage of the turnover, while a higher oil price will increase the government take as it will trigger a higher surplus royalty.

	Former model (before 2020)		Current model for 2020-24	
	Nominal rate	Effective rate*	Nominal rate	Effective rate*
Royalty on turnover	2.5%	5.5%	0 %	0%
Surplus royalty	7.5/17.5/30%	12.9%	3.75/8.75/15%	7.2%
Corporate withholding tax	25/36%	29.4%	25/36%	33.4%
Government participation	6.25%	3.6%	0%	0%
Total government take		**51.3%**		**40.6%**

*Table 2: Comparison of current and former government take structure in Greenland. *Note, the effective rate is calculated based upon a scenario with a barrel price of 80 USD. Source: Naalakkersuisut, 2020, Getting Greenland back on track with oil, Nuuk.*

The current government take model provides investors with a larger degree of security compared to the previous model, as investors will only pay taxes and royalties in years where the company generates a profit, and the surplus royalty is modest until the profit exceeds a certain threshold. This also means that if oil prices are low the government take can be below 30%, and in years with very low oil prices, Greenland will receive no or very modest revenues from oil exploration. The actual government take will depend upon the cost structure for the specific license and the global oil price.

Potential investment challenges for oil and gas in Greenland
Throughout the years, Greenland has been able to attract the interest of investors to explore and develop its untapped oil and gas resources. Since the 1970s, several major, independent (ICs), and national oil and gas companies (NCs) have ventured into exploration efforts, which have nonetheless proven commercially unsuccessful.

Several “bursts” of interest in the country by relevant industry players have been followed by the subsequent abandonment or postponement of efforts. In 2015 - in the middle of a plunge in oil prices - DONG Energy (now Ørsted), GDF Suez and Statoil (now Equinor) handed their licences back (Reuters, 2015). Simultaneously, Shell, Mærsk and Cairn Energy announced the temporary postponement of its interest in the further exploration of oil and gas in Greenland (Kalaallit Nunaata Radioa, 2015). But even before the low-price environment of 2015, ExxonMobil turned in its back on Greenland’s prospects (Børsen, 2013).[4]

If the resource potential exists and regulatory conditions have been mostly favourable, then other elements must have played a role in the sentiment of potential investors in Greenland’s oil and gas sector. A combination of factors may explain why the development of Greenland’s oil and gas resources has been perceived as a less attractive opportunity than alternatives, including those available in comparable Arctic territories. Among these are:

- Greenland’s limited infrastructure
- Transportation challenges during the winter months, which could drive costs up
- Uncertain exploration, development and production costs
- Limited access to skilled and semi-skilled labour
- Heavy reputational cost associated with the potential environmental damage

Given the present-day situation of Greenland as a country with substantial undiscovered oil and gas potential, it is worth reviewing how much time would elapse between discovery and production at a commercial scale. Earlier experience in the Arctic (e.g., Norway, Russia, Alaska) has shown that one decade is the average time between exploration and production, and that exploration campaigns tend to be long-lasting, uncertain and costly efforts. In

[4] Cairn Energy’s exit came after having reportedly spent more than one-half billion USD by 2012 (BBC News, 2011), to later (in 2015) officially declare that it was relinquishing all licences in Greenland, except for the one containing the Pitu Prospect (in Baffin Bay). Associated exploration costs were either impaired or written off, according to the firm’s financial reports (Cairn Energy, 2015).

other words, a successful discovery happening now (2021) could be expected to come on stream first in approximately 10 years, i.e., by the early 2030s at the earliest.

Given the challenges discussed, it could be argued that it is already too late for Greenland to become an oil and gas producer. Particularly because the green transition risk, i.e., the risk (perceived or real) that a fossil investment may become obsolete because of a speedy transition to renewables, may materialise sooner than previously expected. With this line of reasoning in mind, it could be said that Greenland has missed its “first mover advantage” already, whereas this has been successfully exploited by other Arctic territories. Alaska, Russia, and Norway are presently well-established oil and gas territories after decades of continued interest by oil and gas companies and a sustained effort by governments to design attractive framework conditions.

Investors may thus feel more attracted to investing in oil and gas provinces where there is less uncertainty and would prefer alternatives where they are able to secure shorter investment cycles. In the cash-constrained environment of recent years (due to low prices and not least COVID), the investors’ interest has been in more brownfield and expansion projects with safer returns, than in greenfield projects with less certain ones.

If investors would still like to bet on Arctic investments, then alternative territories (Norway, Russia or Alaska) may be perceived as a more interesting option. Reasons for this may include that there may be a better possibility to agree on joint ventures with other companies, because the geological aspects are better understood, or simply because the regulatory conditions tend to adapt more quickly in order to keep investors’ interest alive.

More generally, in the face of an imminent green transition, investors may wish to disregard the Arctic entirely and bet on other provinces that represent a lower technical and environmental challenge, but also a lower reputational risk. In other words, an oil and gas company with a position in, for example, the North Sea, Africa or the Middle East may prefer to increase its presence there, rather than diversifying to frontier territories like the Arctic, which are considered so sensitive.

It is likely that investor sentiment, rather than technological availability, is the central factor to discourage potential entrants to the Greenlandic oil and gas business. In fact, relative to the time of Cairn Energy’s exploration campaign in

Greenland, technological solutions (e.g., FPSO) have progressed significantly and have become more cost-effective. The oil and gas industry appears to have adapted to a lower-price environment and has, overall, become better at delivering on time and on budget. Nonetheless, the overall economic environment has become considerably more uncertain.

All things considered, potential investors in the Greenlandic oil and gas sector may be scarce but still existent. One investor type could be characterised by a higher risk tolerance, i.e., an appetite for less certain but higher return investments. Such an investor could perhaps focus on a shorter-term strategy, by which it places its effort on making a commercial discovery, which it may not necessarily produce. It is not entirely uncommon for some companies to focus on exploration rather than on production.

Alternatively, the country may attract investors who see the opportunity of entering Greenland as a strategic – possibly geopolitical – stake in one of the world's frontier environments. A combination of capital and interests from national companies (possibly from rapidly growing economies such as China or India) in cooperation with the technical and business expertise of countries with solid Arctic experience (Russia's independent and national companies, for instance) may find it attractive to approach Greenland. These investors would not necessarily focus on a short to mid-term exploration and development strategy but would instead secure their position with a longer-term perspective in sight.

Green Transition and climate change risks

As a result of an imminent green transition, companies involved in the production of fossil fuels face a higher risk of operating assets becoming stranded in the foreseeable future. Whether the green transition will mean that demand for fossil fuels will vanish in one, two, three or more decades remains uncertain, and energy companies appear to be decided to diversify their portfolios.

However, most oil and gas producers are not abandoning their positions all at once and are, in fact, continuously rebalancing their portfolios, through joint ventures and other agreements that help them mitigate the risks. In general, oil and gas producers appear to be juggling to secure mid- to long-term shareholder value, manage reputational risk, and avoid falling into obsolescence.

Potential strategies to attract investments to the Greenlandic oil and gas sector
To attract investor interest in developing Greenland's oil and gas resources, a starting point is to re-assess the comparative advantages of its take structure relative to other Arctic territories.

However, an attractive take structure may be necessary but insufficient to attract investors, as there are other established regions in the Arctic offering better conditions with respect to important elements such as infrastructure and the overall geological knowledge of basins. Additional efforts, such as climate compensation may play an important role to brand Greenland as a climate-responsible territory.

Furthermore, there is a need to develop a comprehensive risk assessment, which accounts for the multi-dimensional implications of developing oil and gas in Greenland. This includes, but is not limited to, the geo-political and environmental implications of associating with potential entrants, which could be outside the more traditional scope of major oil and gas producers.

Can Greenland's oil resources be exchanged to carbon offset projects?
Carbon offsets are a market mechanism by which entities emitting carbon and other greenhouse gases compensate their direct emissions with reductions taking place elsewhere. In practice, an industrial activity may be limited in its ability to manage or reduce its *direct* carbon footprint but can instead offset it through the financial support to projects that reduce carbon and greenhouse gas emissions, thereby *indirectly* reducing its carbon footprint.

In the oil and gas industry, there is one recent (probably the first) example of a carbon-offset crude oil delivery taking place between an upstream producer (Oxy) located in the Permian Basin (USA) and a large industrial consumer in India (Reliance Industries) (Veazey, 2021).

Required IRR for projects in Greenland
On average, financial sources indicate that oil and gas industry projects have recently settled at an average Internal Rate of Return (IRR) of 15-20%, after improving project execution in recent years. Earlier projects – despite higher prices – tended to result in more moderate returns of approximately 10%.

Complex oil and gas projects in regions such as the Caspian Sea and the Arctic had been previously characterized by massive blowouts. However, improved discipline together with a stronger focus on brownfield, expansion, tie-back and - not least - smaller projects have increased cost-efficiency.[5] Among the projects praised by its on-budget executions, despite its complexity is Yamal LNG, which has been led by Russian independent Novatek (Venables, 2018).

Potential value of oil reserves

Based on the above reserve estimates and oil price scenarios, a simple analysis of the potential value of Greenland's oil reserves that can be extracted within the next 30-40 years was undertaken. The analysis focuses primarily on the economic costs and benefits of offshore oil extraction, and therefore the analysis did not focus on onshore oil, nor natural gas production. This is because estimated onshore oil reserves are not assessed to be large enough to support a full oil development effort alone, and with respect to gas, this would require the establishment of very expensive LNG terminals in order to become a major exporter, and this is not deemed to be a realistic first step in Greenlandic hydrocarbon development.

Input assumptions

Nunaoil A/S has provided significant input in the form of CAPEX and OPEX proxy figures for each of the potential projects included in the analysis, as well as commenting on Ea's selection of various parameters. In Southwest Greenland, it is assumed that three projects can theoretically be initiated over the next ten years, while due to more difficult ice conditions in Northwest Greenland, it is assumed that one major project is more realistic. An overview of the most relevant input assumptions is displayed in Table 3.

Annual oil production from the 4 hypothetical projects was assumed to follow a somewhat standard oil production profile, i.e., a steep ramp up phase, proceeded by a period of peak production, followed by falling production.

[5] Tie-back is an engineering process connecting an untapped satellite oil field to an existing production center. Source: [What Is The Foremost Consideration For Subsea Tiebacks? (auduboncompanies.com)](auduboncompanies.com).

Parameter	unit	SW1	SW2	SW3	NW
Field and reservoir characteristics					
Field size (extractable)	mboe	250	250	250	650
Water depth	meters	0 - 200	0 - 200	200 - 1,500	0 - 200
Reservoir depth	meters	2,000	3,000	4,000	3,000
Upfront and restoration costs					
Exploration	Mio. USD	$400	$520	$800	$750
CAPEX	Mio. USD	$5,800	$6,200	$6,600	$16,800
Restoration	Mio. USD	$600	$650	$700	$1,200
Operating costs					
OPEX	USD/boe	$15	$17	$20	$25
Transport	USD/boe	$3	$3	$3	$6
Time periods					
start year	year	2022	2025	2028	2025
Preparation	years	3	3	3	3
Exploration	years	6	6	6	7
Construction	years	6	6	6	8
Production	years	20	20	20	20
Restoration	years	3	3	3	4

Table 3: Standard assumptions utilised in IRR and NPV analysis of hypothetical oil fields SW and NW of Greenland.

Calculating Greenland's Government take

It has been assessed and described above that oil companies, as a general rule, require an internal rate of return well above 10% when investing in new areas.

For each of the analysed projects, calculations have been undertaken of the internal rate of return for the oil company, cash flows during the project period, and the present value of the return (take) for Greenland. The present value is calculated with a government discount rate of 3%, and the take structure is simplified and interpreted in such a way that "take" first starts being generated when the individual project reaches financial break-even. The time of break-even is calculated as the time when accumulated income exceeds accumulated costs (excluding return on capital). After this time, 33.4% of the profit is paid as a return to Greenland. Note that this is a simplification of the current take structure.

IRR and NPV Results

The figure below displays the IRRs[6] for all 4 projects given 3 different oil price scenarios.

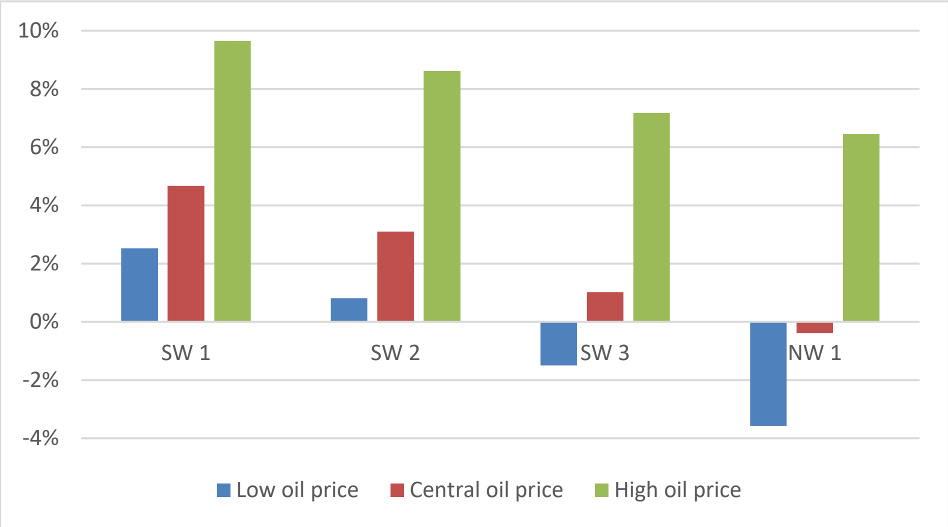


Figure 5: Internal rate of return (IRR) for 4 hypothetical oil projects in Greenland given 3 different oil price scenarios.

As can be seen from the figure, the calculated IRR did not exceed 10% for any of the projects, even in a scenario where the oil price averaged $88/barrel during the oil production years. In fact, even if the desired IRR level were lowered to 7.5% for an oil company, only the first 2 projects off the SW coast of Greenland would exceed this threshold, and only in a scenario with high oil prices.

These findings illustrate that given the assumed field sizes and CAPEX & OPEX costs, only an oil company that forecasts oil prices in excess of $90/barrel and is willing to accept anticipated returns well below the norm (i.e., 9.7% for SW 1 and 8.6% for SW 2), would be likely to undertake investment in Greenland. In such a scenario, the NPV of the Greenlandic portion of the SW 1 project would be 1.66 billion USD, while the NPV of the SW 2 project would be 1.40 billion USD.

Sensitivity analysis with lower CAPEX

With the above assumptions, it is considered unlikely that an oil company will invest in oil production in Greenland. As a sensitivity, the consequence of a lower CAPEX has been analysed. The following figure displays the IRRs for the various projects given varying oil price scenarios with 25% lower CAPEX.

[6] Tax implications are not incorporated in the simple project IRR calculations

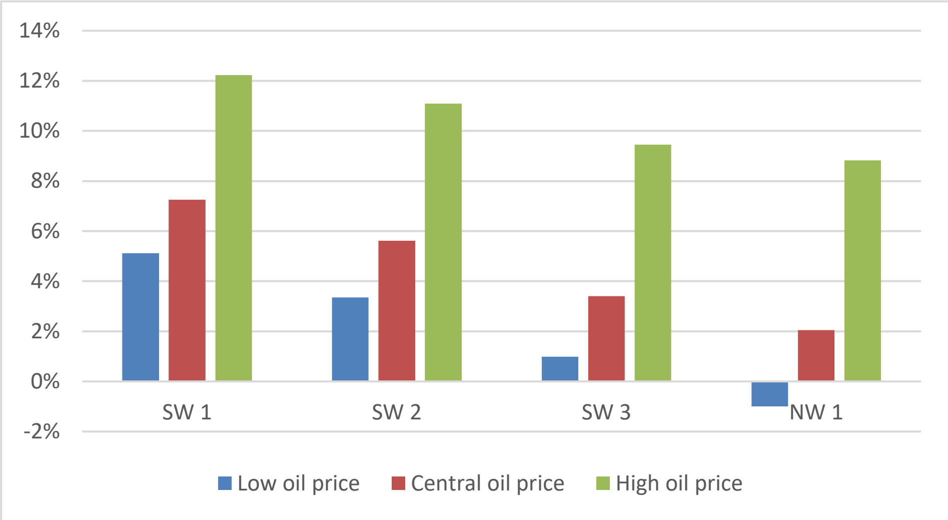


Figure 6: Internal rate of return (IRR) for 4 hypothetical oil projects in Greenland given 3 different oil price scenarios assuming lower CAPEX.

In a situation where CAPEX is reduced by 25% relative to the standard assumed values, and in a scenario assuming oil prices averaging close to $90/barrel, the first two hypothetical projects of the SW coast of Greenland would generate an IRR in excess of the assumed 10% bare minimum.

The table below displays the potential Greenlandic NPV for all 4 projects assuming *both* low CAPEX *and* high oil prices.

	Project IRR	Greenlandic NPV (billion USD)
SW 1	12.2%	$1,9
SW 2	11.1%	$1,6
SW 3	9.5%	$1,3
NW 1	8.8%	$3,1
Total all projects		$8.0
Total for projects with min 10% IRR		**$3.6**

Table 4: Standard, High, and Low CAPEX values utilised in the IRR analysis of hypothetical oil fields SW and NW of Greenland.

IRR and NPV Conclusions

Given the assumed standard CAPEX and OPEX values and oil quantities utilised in the current analysis, it is not likely that an oil company would find it economically attractive to undertake oil investments in the hypothetical projects described within the current analysis.

If an oil company both assumed that oil prices would average roughly 90 USD/barrel (in real terms) for the production period and could achieve CAPEX roughly 25% lower than the standard values assumed here, then the Greenlandic NPV assuming 33.4% government take could be roughly 3.6 billion USD.

It must be emphasised that there are significant uncertainties regarding the assumptions in the analysis, especially regarding the development of the oil price and the oil companies' return requirements. It is therefore important to state that the findings here do not conclude that there are no fields in Greenland that may be economically attractive to explore. However, this quick screening does highlight the potential challenges that developers may have in finding economically attractive projects in Greenland.

Conclusions and SWOT analysis

The two core questions that Ea was posed with answering in this analysis were:

- What is the likelihood of Greenland can become an oil exporting country in the future?
- And what are the economic potential and environmental challenges?

Due primarily to a series of economic challenges, some of which are related to the local and global environment, the analysis undertaken within the current study indicates that it is unlikely that Greenland can become an oil exporting country in the future. However, Ea suggests that there is a 3rd question that bears answering as well, namely:

- What are the consequences of Greenland maintaining an ambitious and offensive oil strategy?

I.e., it is almost certain that Greenland is home to significant oil and gas resources, so what are the benefits and drawbacks of keeping the door to potential investment open, particularly if circumstances change in the years to come.

Whether or not to maintain an offensive oil strategy is a political decision that the people of Greenland and their elected officials should undertake. To support this discussion, a brief SWOT analysis was undertaken, the results of which are summarised below.

Strengths

- It keeps an option open for Greenland. Oil prices have historically been very difficult to forecast, and if very high prices occur again, Greenland would be in a position to capitalise
- Attractive cooperation partner for US, China, Russia and others.
- Time, effort, and funding spent on developing the current knowledge base are not lost.

Weaknesses

- If interest continues to be very low, it could be a futile effort, and would therefore take focus, funding, and efforts from other strategic areas.
- Continuing to promote the possibility might be perceived as unrealistic government dreaming.

Opportunities

- Ensures that opportunities for workplaces and income streams are not lost, even if the chances of largescale oil export are small.

Threats

- Greenland has a chance to be branded as an "Environmentally friendly state". An ambitious oil strategy might jeopardise this in the eyes of those in Greenland, and abroad, particularly amongst younger people.
- If development is undertaken, the risk of environmental damage and economic effects on fishery, hunting and tourism of a large oil spill are quite low, but if a spill did occur, the effects could be catastrophic.

3 Introduction

3.1 Report purpose and research issue

The purpose of the report is to provide political decision makers with insight in the economic potential and likelihood of Greenland becoming an oil exporting country in the years to come, and potential environmental implications of this. The report provides an overview of the estimated carbon resources in Greenland, its economic potential, the expected development in the global oil market, and the environmental impact from oil exploration in Greenland. The report shall also draw a picture of the compensatory global policies towards oil exploration. The point of departure of the report is existing analysis and reports from Greenland and international sources.

Based upon the information presented, the primary research issue to be addressed is: What is the likelihood of Greenland can become an oil exporting country in the future? And what are the economic potential and environmental challenges?

3.2 Report inputs, analysis, and conclusions

The majority of inputs to the report were provided by Nunaoil A/S (the national oil company of Greenland), and various Government of Greenland departments. Ea Energy Analyses was responsible for compiling and editing these inputs into the current report. All analysis and conclusions undertaken on the basis of the provided inputs are those of Ea Energy Analyses and are not the official stance of any of the Government of Greenland departments.

4 Historic overview of Oil exploration in Greenland and the Arctic

4.1 Governing hydrocarbon exploration in Greenland

The discovery of the Prudhoe Bay oil field in Alaska during the end of the 1960s spurred an interest in oil exploration in the Arctic areas including Greenland, and this interest was further fuelled by high oil prices in the early 1970s due to the first oil crisis.

From its onset, activities related to hydrocarbon exploration and exploitation in Greenland were administered by the Ministry of Greenland in Copenhagen, but in 1979 Greenland attained a Home Rule Government. From that point, decisions relating to hydrocarbon exploration and exploitation were moved to a Joint Committee of politicians from their respective parliaments. During the period between 1979 and 1999, the administrative tasks were dealt with from an office in Copenhagen (The Mineral Administration for Greenland, MRA; Christiansen, 2011), but in 1999 the administration moved to Nuuk under the Bureau of Minerals and Petroleum (BMP; Christiansen, 2011).

As a part of the negotiations with the Danish Government for a new Self-Rule law in 2009, the rights to exploration and exploitation of minerals and hydrocarbons in the Greenland subsoil were fully attained by the Greenland administration in 2010.

As part of a wish from Greenlandic politicians, NUNAOIL, the national oil company of Greenland was founded in 1984, with an equal share between Greenland and Denmark, but in 2010 Greenland bought Denmark's share and it is now fully owned by the Government of Greenland.

4.2 History of Greenland Exploration - Activities

The first exploration related activity in Greenland commenced during the early 1970s with the acquisition of almost 21,000 km of seismic data as part of prospecting licenses in the offshore waters of West Greenland (Christiansen, 2011).

In 1974, six groups lead respectively by Amoco, ARCO, Chevron, Mobil, Total and Ultramar, were rewarded 13 offshore exploration licenses covering an area of 19,082 km^2 off the west coast of Greenland (Christiansen, 2011). During the following years, five exploration wells were drilled, but of the five wells, only the first, the Kangâmiut-1 well, encountered hydrocarbons in the form of gas, but due to technical issues, the well never flowed. By early 1979 all licenses were released, and offshore exploration ceased until 1996.

During the 1980s, exploration only took place onshore on Jameson Land, where ARCO, Arktisk Minekompagni A/S and NUNAOIL A/S signed a concession agreement in January of 1985 for an area of roughly 10,000 km^2 and acquired a total of 1,798 km of 2D seismic data during the period of 1985-1989. Exploration was both conducted during the winter and summer seasons and included a number of geological studies. By the end of 1990, the license was relinquished, mainly due to a drop in oil prices and what was interpreted to be unfavourable geological settings for doing a commercial discovery.

As part of an exploration strategy formulated in the early 1990s, a new licensing round opened in 1992. However, as no applications were received it was decided to turn to an open-door policy for the offshore areas south of 70°30’N in West Greenland.

In 1996, outside of the normal licensing round procedure, Statoil and its partners (Phillips, DONG and NUNAOIL) were granted a license in southwest Greenland. After acquisition of exclusive 2D seismic data, the Qulleq-1 well was drilled in the summer 2000. The results from the well were disappointing and downgraded the perceived perspectivity of the area. By the end of 2001, the consortium finally released the license.

A strategic oil seep sampling program onshore Disko and Nuussuaq in the early 1990s created some industry interest. This resulted in an application for a prospecting license from GrønArctic in 1994, and an exploration and production license the following year. Initial drilled core holes provided promising results, but a later well was less promising, and GrønArctic relinquished its license in 1994 (Christiansen, 2011).

Promising offshore results in Norway, combined with findings from the NAD project in the late 1970s to early 1980s which suggested prospective areas analogues to the conjugate Norwegian margin, lead to the Geological Survey of Greenland (GGU) in 1986 proposing that several major oil companies investigate an area in NE Greenland (Christiansen, 2011). In late 1989 negotiations were finalised, and in what became known as the KANUMAS (Kalaallit Nunaat Marine Seismic) project, a prospecting license was issued to a consortium of six major companies: BP, Exxon, Japan National Oil Company, Shell, Statoil, and Texaco, with NUNAOIL participating as a carried partner and operator for the consortium (Christiansen, 2011).

During the period 1991-1995, the consortium acquired 4,071 km of 2D seismic data in the Baffin Bay, Northwest Greenland, and a total of 6839 km in Central and Northeast Greenland using the Danish navy vessel Thetis (Christiansen, 2011). For their early efforts, the companies in the consortium would gain a preferential status if licensing rounds would open in NW and NE Greenland.

New millennium brings better data

At the beginning of the new millennium, the exploration strategy changed, following the philosophy that new seismic data sets would show the possibilities the geological settings could offer. Thus, instead of attracting attention from exploration and production companies, the focus changed to attracting seismic acquisition companies to acquire new modern high quality seismic datasets with better imaging of the deep sedimentary basins.

During the 2000s, a number of licensing rounds opened up in the offshore areas of West Greenland with deadlines in mid-2002 and late-2004 for areas in the Southwestern Greenland and a third licensing round in the Disko West area with a deadline at the end of 2006.

As a result of aggressive seismic data acquisition and the many licensing rounds the Atammik license (3985 km^2) in southwest Greenland was granted in 2002 to EnCana followed by a second granting to EnCana of the Lady Franklin license (2897 km^2) in 2005 (Christiansen, 2011).

The Disko West licensing round was two-phased, with an initial phase of eight predefined blocks west of Disko and a later second phase under an open-door award system. The predefined blocks had sizes ranging from more than 10,000 km^2 to close to 14,000 km^2 and during the first phase seven of the eight blocks were awarded during 2007 and 2008 to joint ventures consisting of a combination of oil majors (e.g., Chevron and ExxonMobil) and medium sized companies (Cairn, DONG, Husky and PA Resources) (Christiansen, 2011).

As part of the open-door award system, Cairn later in 2008 applied for and acquired four large licenses (> 10.000 km^2 each) around Cape Farewell and farmed-in the two EnCana licenses (Atammik and Lady Franklin) (Christiansen, 2011).

In 2008, Husky acquired the first 3D seismic surveys on the Greenland shelf in its two license blocks (Kangerluk and Ikermiut - 2,171 km^2 in total), showing that it was possible to acquire this type of data in iceberg infested areas. Later in 2011 and 2012, 3D seismic acquisition was acquired in even harsher conditions, in the Baffin Bay and Cape Farewell.

By 2015, all the exploration licenses in Disko West had been relinquished due to difficulties in finding drillable prospects in the challenging volcanic covered license areas.

During the years 2010 and 2011, Cairn drilled a total of eight exploration wells in its license areas. As a consequence of the Deepwater Horizon blow-out in the Gulf of Mexico, the operator opted to introduce a two-rig operation for the drilling program. Since then, the Greenlandic Government has adopted this two-rig policy for future exploration drillings.

In 2010, three wells (Alpha1-1, T4-1 and T8-1) were drilled in the volcanic covered Disko West province, and the following year the company drilled five wells. Three were drilled in its southwestern licenses (Lady Franklin, LF7 and Atammik, AT2-1 and AT7-1) and two more in its licenses in Disko West (Gamma-1 and Delta-1). Though the outcome was disappointing, it did show that it was technically possible to drill safely in Greenlandic waters.

Since the time schedule for the licensing rounds during the 2010s was made publicly available at an early stage, it provided data acquisition companies with plenty of time prior to the opening of license rounds. This led to a willingness for companies to invest in large data acquisition campaigns of both seismic data, airborne potential field data and seabed samples prior to opening of licensing rounds.

In 2008, Statoil, on behalf of the KANUMAS group, acquired 11 shallow cores in the Greenland Sea (NE Greenland) using two vessels, the Swedish icebreaker Oden, and the coring vessel Vidar Viking.

In late 2009, after the KANUMAS group had renounced its preferential status in the Baffin Bay, the licensing round for the Baffin Bay area was announced with a deadline for application being May 1st, 2010. The Baffin Bay licensing round was a success, with 17 applications from 12 companies and the granting of seven licenses.

The applicants consisted of major international companies (e.g., ConocoPhillips, Shell, Statoil) and mid-sized companies (e.g., Cairn Energy, DONG, Faroe Petroleum, Mærsk) and there was competing offers on several blocks leading to extensive work programs for the granted license blocks. In early 2011, seven exploration and production licenses were awarded to five different consortia.

During the following two years, 2011 and 2012, the Baffin Bay area experienced a large increase of data accumulation. In particular, there was a substantial amount of 3D seismic data (more than 12,000 km^2), 2D seismic data and 11 shallow boreholes along with seabed sample campaigns collected, thus providing valuable new insights into the basin configuration and its prospectivity. Also, several meteorological, oceanographic and ice data studies were undertaken as part of the committed work programs.

By the end of 2012, the joint ventures had completed their geological and geophysical work programs and the following year was used to process and interpret the acquired data and decide whether they should enter into the second sub-period. For all joint ventures, the second sub-period included drilling of an exploration well, meaning a substantial increase in financial exposure. By June of 2014, the global price of crude oil plunged, jeopardising the commerciality of prospects in the Baffin Bay licenses and the joint ventures decided to relinquish their licenses by the end of 2015.

At the beginning of 2012, the Greenlandic authorities opened a two-phased licensing round in the Greenland Sea (NE Greenland). The license area consisted of 19 predefined blocks covering a total area of 50,000 km^2 that had been nominated by the KANUMAS group (BP, Exxon, JNOC, Shell, Statoil, and Texaco). In the first phase, predefined blocks covering an area of 30,000 km^2 was on offer and reserved for consortiums that included at least one of the KANUMAS companies. By the deadline in December of 2012, four licenses were granted to three consortia. In the second phase, all the areas that were not covered by licenses granted in phase 1 could be applied for by all companies that had passed a pre-qualification procedure. By the deadline in October of 2013, one license was granted, thus bringing the total number of licenses in the Greenland Sea to five.

As in the Baffin Bay licensing round, there were competing bids on the same blocks, and this led to extensive work programs in the granted blocks. At the time of license granting, the seismic coverage was sparse due to the harsh environment and the sea ice cover, which means that seismic data acquisition is done using two vessels, an icebreaker, and a seismic survey vessel, and hence acquisition of 2D seismic data constituted a large part of the work programs. Instead of each consortia doing their own seismic data acquisition, it was decided to follow a model proposed by TGS-NOPEC, where TGS-NOPEC would do the acquisition on behalf of all the operators.

TGS-NOPEC would commit to acquire each operator's seismic program, while the operators would commit to buy seismic lines outside their license areas. Along with seismic acquisition, the work programs also included seabed sampling and geological studies onshore Northeast Greenland. The very high costs of data acquisition, the low oil price, and the extremely high costs of drilling and development scenarios meant that the commerciality of prospects in the Greenland Sea was severally hampered, and by the end of 2010s (2018 and 2019), the operators relinquished their licenses.

Today (2021) more than 120,000 kilometers of 2D nonexclusive seismic data exist on the West Greenland margin. In some cases, the seismic acquisition was cosponsored by BMP and/or NUNAOIL. The table below displays the number of line kilometres of 2D seismic data and 3D seismic coverage per decade starting from the 1970s and through to the 2010s.

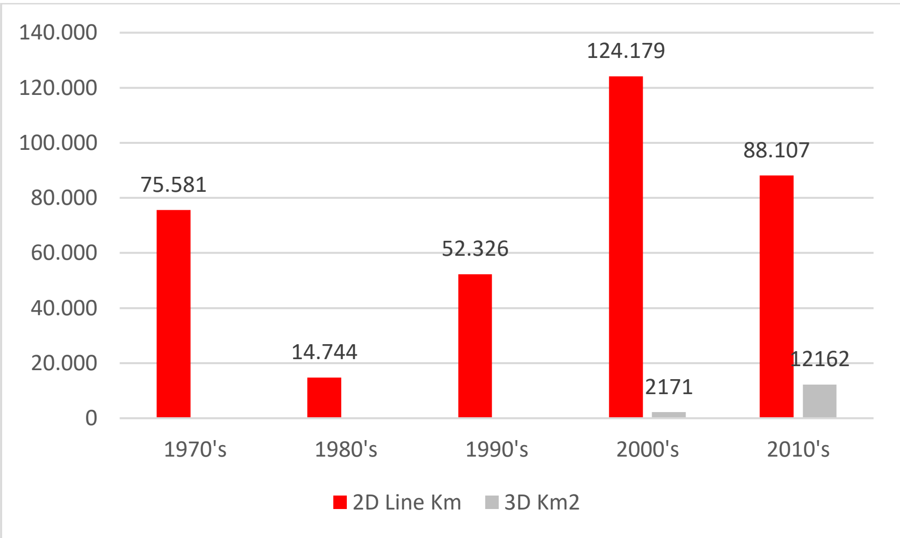


Figure 7: Number of 2D seismic line kilometres per decade and 3D coverage in km².

Currently (2021), there are four active exploration licenses, three onshore (which are described in more detail in the following chapter).

The figure below displays the licensed areas within each decade, starting from the 1970s to present day.

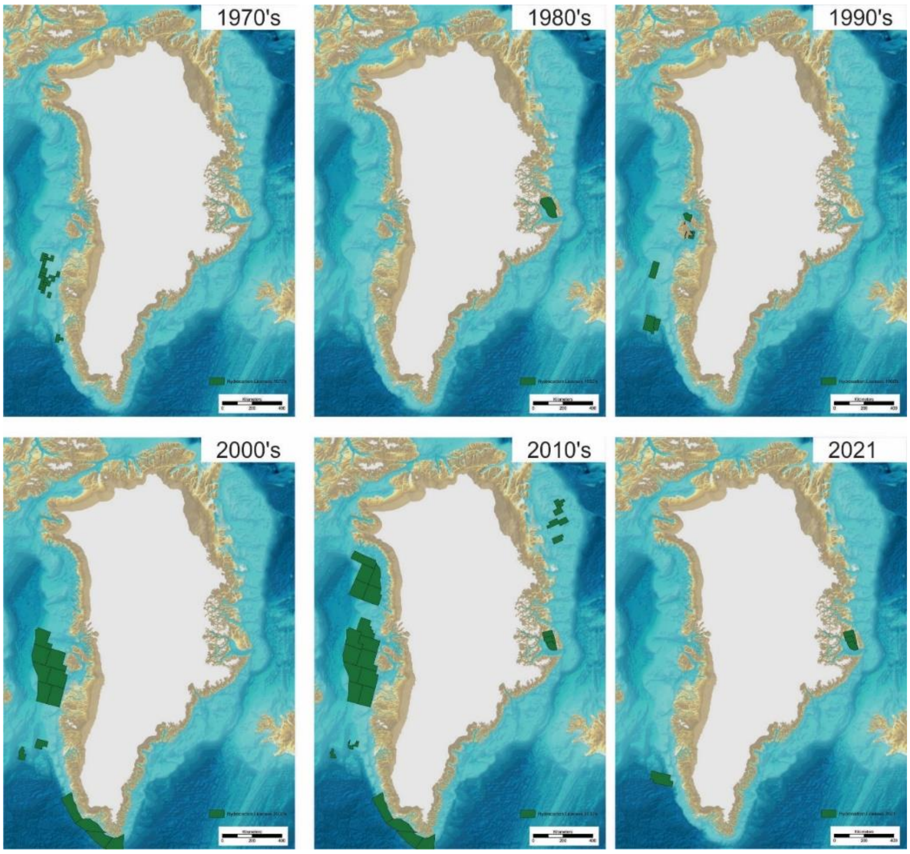


Figure 8: Maps showing the different licensed areas within each decade starting from 1970's to present day. Note that all licenses may not have been active throughout the whole decade, so the maps show the maximum number of licenses within each decade.

Lastly, the map below displays all the various license areas that have been offered since the 1980s, either as licensing rounds or as part of an open-door system.

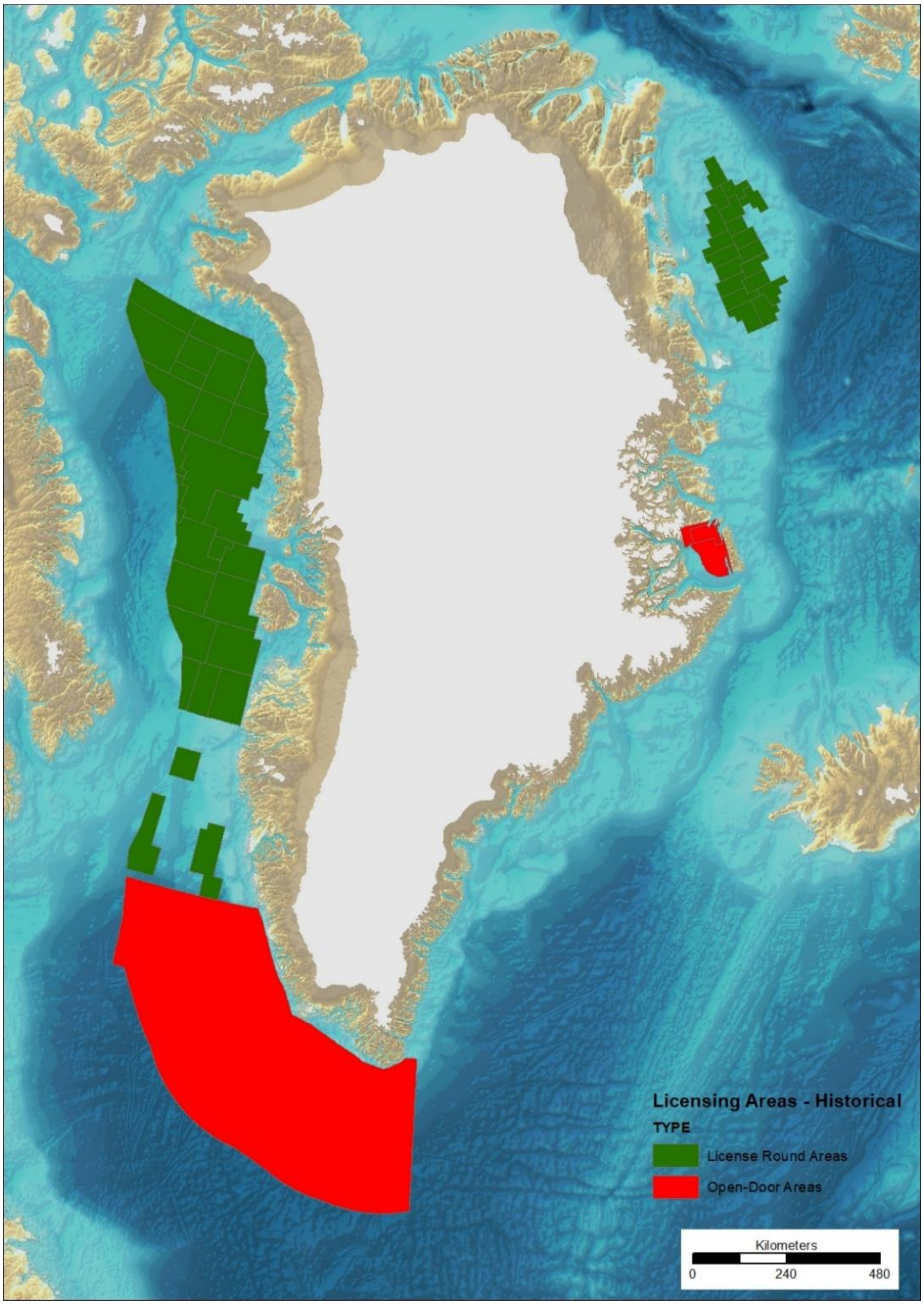


Figure 9: Map showing all the various license areas that have been offered since the 1980s, either as licensing rounds or as part of an open-door system.

5 Status of Greenland's oil and gas activities and estimated hydrocarbon resources

5.1 Status of Greenland's oil and gas activities

Hydrocarbon licences in Greenland can be granted as either a prospecting licence or as an exploration and exploitation licence.

Prospecting licence

A prospecting licence for hydrocarbons gives a non-exclusive right to carry out activities that could help decide whether, and if so in which area, exploration for hydrocarbons should be done. Prospecting licences are typically granted for a period of four years and are automatically surrendered when the period expires. The licensee does not have any obligation to perform activities under the licence and the licence is therefore typically not surrendered before the end of the period even though the licensee has the right to do so. Standard terms regarding prospecting licences can be found on the Government of Greenland website (Government of Greenland, 2021c).

Exploration and exploitation licence

A licence for hydrocarbons is given as exclusive rights to explore and exploit hydrocarbons within the given licence area on the given terms. Exploration and exploitation licences are typically granted for a period of ten years. This period is divided into three sub-periods. Each sub-period includes commitments that the licensee is obligated to perform. Before the end of each sub-period the licensee can choose to move into the next sub-period or to surrender the licence.

Current licences

As of February 2021, there were six active prospecting licences and four active exploration and exploitation licences. An overview of these 10 active hydrocarbon licences is provided in Table 5. More detail on all licences and licence holders can be found on a Government of Greenland website (Government of Greenland, 2021a).

In addition to the 10 active licences, there are three exploration and exploitation licences that are in the process of being surrendered.

Licence No.	Licensee	Region	Licence Period	Status
Active hydrocarbon exploration and exploitation licences (exclusive)				
2015/13	Greenland Gas and Oil A/S & NUNAOIL A/S	Onshore: East Greenland	2015 - 2027	Planning exploration drilling program
2015/14	Greenland Gas and Oil A/S & NUNAOIL A/S	Onshore: East Greenland	2015 - 2027	Planning exploration drilling program
2017/14	Panoceanic Energy Limited & NUNAOIL A/S	Offshore: West Greenland	2018 - 2028	Company in dissolution
2018/40	Greenland Gas and Oil A/S & NUNAOIL A/S	Onshore: East Greenland	2019 - 2028	Planning exploration drilling program
Active hydrocarbon prospecting licences (non-exclusive)				
2017/15	CASP	Onshore: East Greenland	2017 - 2021	Currently, activities are largely on pause due to Covid-19.
2018/13	GX Technology Corporation	Offshore: West Greenland	2018 - 2022	
2018/24	TGS-Nopec Geophysical Company ASA	Offshore: East Greenland	2018 - 2022	
2018/38	Petroleum Geo-Services	Offshore: West Greenland	2018 - 2022	
2019/08	TGS-Nopec Geophysical Company ASA	Offshore: West Greenland	2019 - 2023	
2019/09	TGS-Nopec Geophysical Company ASA	Offshore: North Greenland	2019 - 2023	

Table 5: Overview of active hydrocarbon licences in Greenland

The four active exploration and exploitation licences are held by two companies, Panoceanic Energy Limited and Greenland Gas and Oil A/S (GGO). The licenses can be seen on a series of maps which are available on the Government of Greenland's Oil and Gas Department's website (Government of Greenland, 2021b).

Panoceanic Energy Limited holds one offshore license in West Greenland, but the company is under dissolution. It is therefore expected that this license will be surrendered at the end of the next sub-period.

Greenland Gas and Oil A/S (GGO) holds three onshore licenses on Jameson Land in East Greenland. These licenses are active and GGO has started the planning of an exploration drilling program. The process is still in an early phase and is highly dependent on the licensee availability to raise the needed funds for the project but can be an important step forward for oil exploration in Greenland.

Historical licences

Statistics on the number of hydrocarbon licences from 2010 to 2020 are displayed in Figure 10.

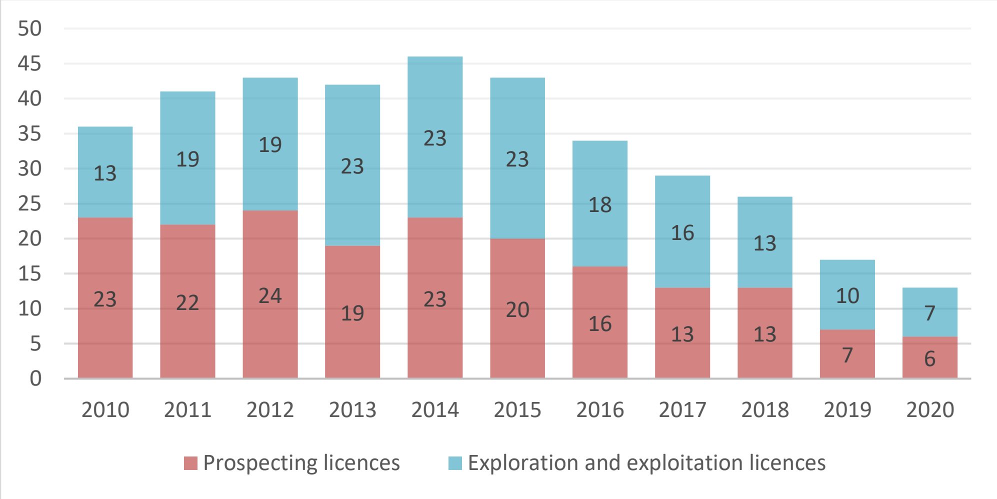


Figure 10: Number of hydrocarbon licences in Greenland. Please note that the number of exploration and exploitation licences include licences under a surrender process. The number of active exploration and exploitation licences today is four, while three licences are in the process of being surrendered.

Future licencing rounds

In 2020, the Government of Greenland launched a new oil and gas strategy covering the period 2020-2024. The strategy includes a plan for the opening of licencing rounds and open-door procedures. The strategy will have a focus on onshore exploration at the Nuussuaq peninsula, where the Government of Greenland has conducted a number of geological studies to outline the oil potential.

The full plan for opening of licencing rounds and open-door procedures in the strategy period can be seen in the table below.

Region (area)	Opening for licensing
Nuussuaq Basin / Disko West (onshore)	February 2020
Davis Strait	November 2020
Baffin Bay	November 2020
Nuussuaq Basin / Disko West (offshore)	November 2020
Northeast Greenland	July 2021
Central East Greenland	January 2022

Table 6: Overview of the plan for opening of licencing rounds

5.2 Estimated hydrocarbon resources in Greenland

Introduction

The following text is from The Whole of Greenland Resource Assessment Project. The aim of the project is to provide the best estimate of the play*-based risked volume of conventional hydrocarbons on the Greenland Shelf and some associated onshore basins in a consistent fashion. The project is carried out to facilitate business decisions and guide the industry towards the most prospective areas, as well as helping the Greenland Authorities and politicians in strategic decision making and in planning future licensing rounds. In addition, it will support the definition of new geophysical and geological de-risking initiatives.

***Play definition**

An often-used concept in oil exploration is the term "play". In its simplest form, the "play" concept means a geographically delimited area controlled by the same set of geological circumstances.

Depending on the level of details, whether the geology of an area is known and its geological development, a play can change over time. In frontier areas like Greenland, the concept play is often used for areas where rocks of a given age, e.g., Late Cretaceous, are expected to be present and where these deposits of Late Cretaceous age are controlled by the same geological circumstances. In areas where the is very little or almost no geological knowledge, a play is more a conceptual model.

As the geological knowledge becomes better, the term play can be used in a more detailed fashion, and e.g., refer to an area where a depositional setting during a specific geological time has been present or a tectonic environment (e.g., areas influenced by salt tectonics), where the same geological circumstances have been present. Alternatively, it could also be an area of discovered oil fields that shares the same geological circumstances.

Hence, within a geographic area, several overlapping plays can exist and often areas containing several plays will be attractive to explore.

This has not been done before and the only comparable study was conducted by the USGS in 2007-2008 for the parts of the Greenland Continental Shelf lying above the Arctic Circle.

The project is conducted by a project partnership consisting of the Geological Survey of Denmark and Greenland (GEUS), the Ministry of Mineral Resources and NUNAOIL, and in combination likely represents the most experienced organisation when it comes to hydrocarbon exploration in Greenland. The project is QC'ed by the Norwegian Petroleum Directorate and the company GIS-PAX, who also supplies the Player® software package used throughout the project.

A description of the data, inputs, and methodology used is included in Annex 1.

Yet-to-Find and Volumetrics

The risked Yet-to-Find volumetrics are divided into two categories, identified Yet-to-Find and Unidentified Yet-to-Find and the risked YTF results from the three assessment units AU1-AU3 are shown in Table 7 below. For more detail on the methodology utilised in determining these figures, and a map over the assessment units (AU), please see Annex 1.

Assessment Unit (AU)	Identified Risked YTF (MMBOE) - mean case	Unidentified Risked YTF (MMBOE) - mean case	Total Risked YTF (MMBOE) - mean case
AU1 - Davis Strait & Labrador Sea - North	1,080	3,070	4,150
AU1 - Davis Strait & Labrador Sea - South	0	1,400	1,400
AU2 - Baffin Bay	2,350	6,750	9,100
AU3 - Disko West and Nuussuaq Basin	107	3,550	3,657
AU4 – North-East Greenland	Not completed		
AU5 - Central East Greenland	Not yet started		
AU6 - Southeast Greenland	Not yet started		
AU7 - North Greenland	Not yet started		
Total			**18,307**

Table 7: The risked Yet-to-Find volumetrics for each assessment unit, divided into identified and unidentified risked YTF (MMBOE). For AU1-South there is no identified YTF, so an average yield per area from AU1-North is used to calculate the unidentified YTF for AU1-South.

The USGS Circum-Arctic Resource Appraisal Estimates

As described earlier, during 2007 and 2008 the US Geological Survey (USGS) conducted the Circum-Arctic Resource Appraisal (CARA) project, in which an estimate of the Yet-to-Find hydrocarbon resources in the Greenland Shelf areas north of the Arctic Circle was included (see Figure 11).

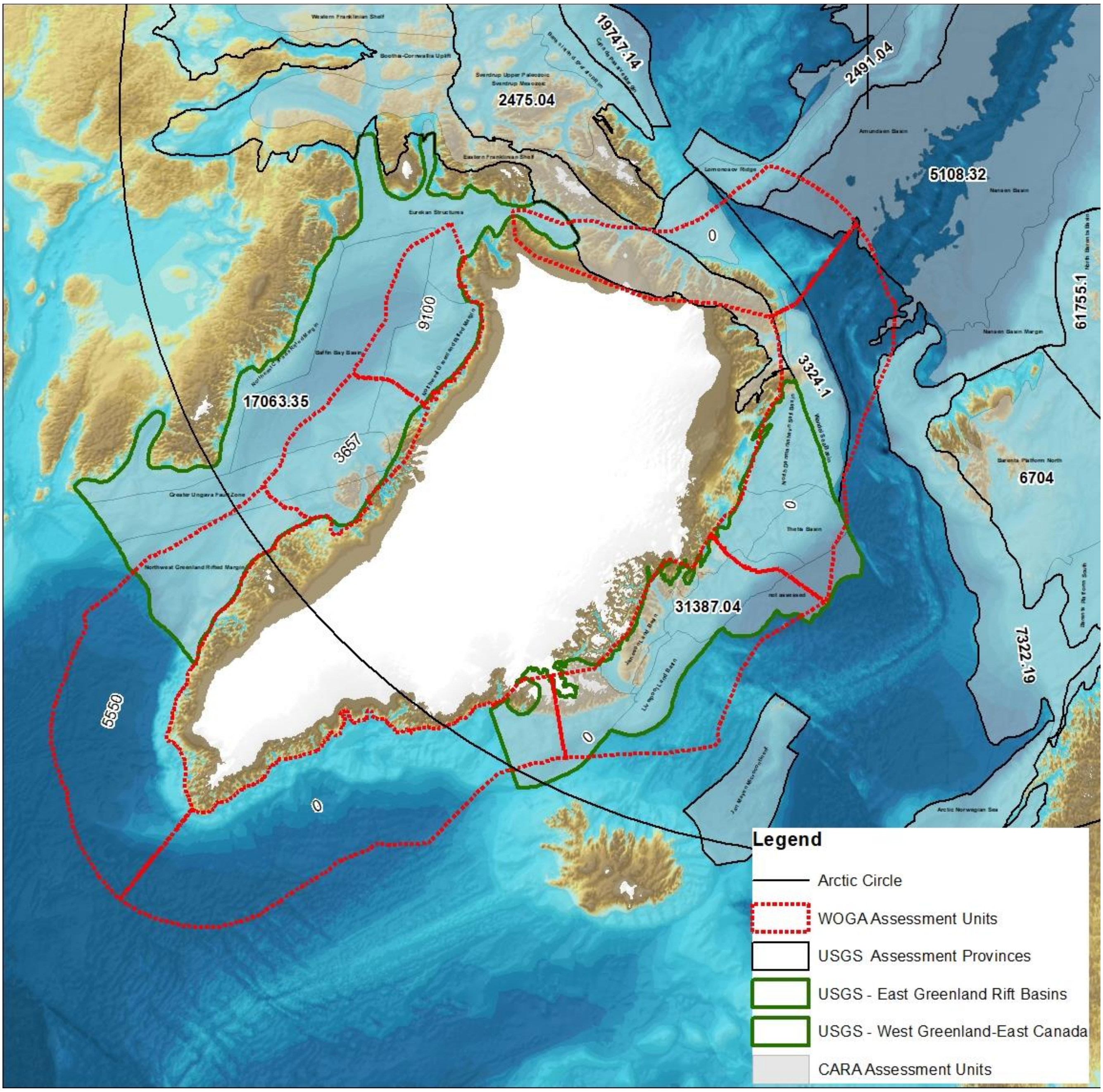


Figure 11: Map showing the different USGS assessment provinces and USGS assessment units and the assessment units used in the whole of Greenland resource assessment. The numbers refer to the mean YTF value for a USGS assessment province or a WOGA assessment unit in MMBOE respectively.

The methodology of the CARA is significantly different from the methodology used in the whole of Greenland Resource Assessment, where the Greenland Resource Assessment uses a mixed deterministic and probabilistic method, the CARA uses exclusively the probabilistic method (Monte Carlo method). The reason for this is to overcome differences in the level of geological knowledge between different assessment units and allow for comparisons between various assessment units by using statistics from a database of geological analogue basins worldwide.

The assessment units used to estimate the undiscovered hydrocarbons on the Greenland Shelf used by the USGS differs significantly from the assessment units used in the whole of Greenland resource assessment and hence besides the difference in the used methodology there are also differences in the assessment unit areas, so a comparison between the two estimates can only be done if it is normalized to area units e.g., per 1000 km^2 and even then, a comparison should be done with caution, since the USGS assessment in West Greenland - East Canada also includes areas within Canadian waters, areas that are excluded in the whole of Greenland resource assessment (see Figure 11 for a comparison between the assessment units used in the two studies).

Table 8 below displays a comparison between the total risked YTF (MMBOE)/area between the results from USGS and the whole of Greenland resource assessment.

Assessment Units	Area (1000 km^2)	Total Risked YTF (MMBOE) - mean case	Risked YTF (MMBOE/ 1000 km^2)
Whole of Greenland Resource Assessment (WOGA)			
AU1 - Davis Strait & Labrador Sea	471	5,550	11.8
AU2 - Baffin Bay	159	9,100	57.2
AU3 - Disko & Nuussuaq Basin	175	3,657	20.8
Total/average West Greenland	**805**	**18,307**	**22.7**
US Geological Survey (USGS)			
West Greenland-East Canada	964	17,063	17.8
East Greenland Rift Basins	530	31,387	59.1

Table 8: Comparison between risked YTF (mean case) in MMBOE per area (1000km^2)

The risked YTF is an estimate of how much original oil and natural gas in-place within a given area at standard conditions (stock tank), see Figure 12 for how this should be understood in relation to terminology for example used by the EIA.

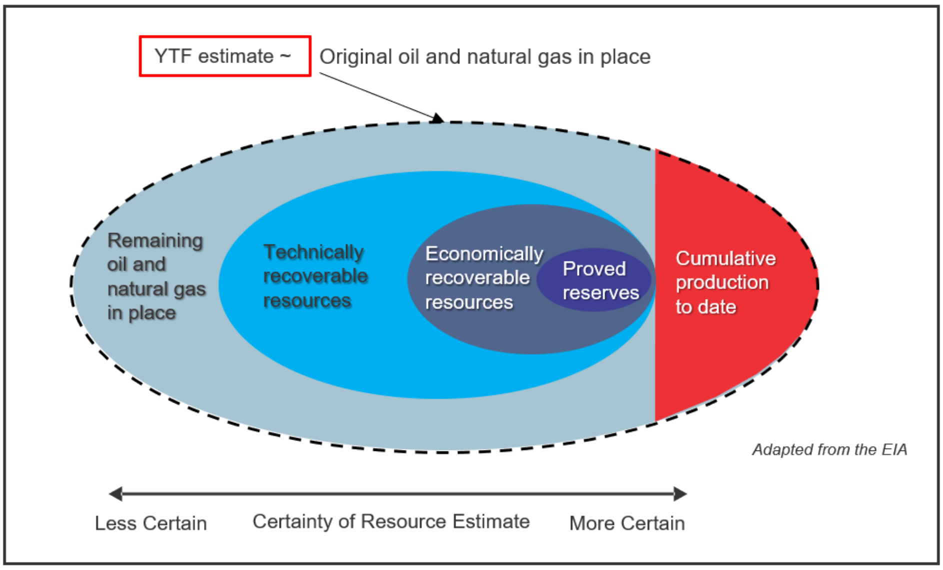


Figure 12: Stylized representation of oil and natural gas resource categorization and how the whole of Greenland Yet-to-Find (YTF) estimate is placed within a certainty spectrum. The YTF estimate of the whole of Greenland resource assessment is an estimate of how much original and natural gas are in place at standard conditions. Note that the ratio between the various classifications is not necessarily to scale.

Seen in the above terms, this means that the current YTF estimate could be considered as possible unproven reserves.

Summary

The whole of Greenland resource assessment (WOGA) study has now completed a resource assessment for the West Greenland Shelf. The findings indicate a mean case assessment of more than 18 BBOE (billion barrels of oil equivalent) with the most potential in the Baffin Bay assessment unit. A previous USGS resource assessment utilised a different methodology and covered an area roughly 20% larger, but its findings were similar in scale i.e., 17 billion BOE (mean case).

The WOGA assessment for East Greenland Shelf is not yet complete, but a previous USGS assessment suggest that resources here could be almost twice those in West Greenland. The USGS 2007 resource assessment for the East Greenland Shelf is estimated to have a mean undiscovered potential of 31.4 BBOE conventional petroleum resources. The updated resource estimates for the WOGA Northeast Greenland assessment incorporating the most recent data will be ready in the spring of 2021.

6 Environmental effects of oil exploration and extraction

6.1 Governmental procedures in relation to environmental aspects of hydrocarbon activities

Situated in the Arctic region, the environment is of great importance for the Government of Greenland. Therefore, all hydrocarbon exploration in Greenland must follow best environmental practices and high international standards to protect the environment.

When applying for a license or an activity in Greenland, environmental, nature and climate matters regarding mineral Resource activities are assessed by the Environmental Agency for Mineral Resource Activities (EAMRA).

Strategic Environmental Impact Assessment (SEIA)

Prior to opening new areas for hydrocarbon exploration and exploitation licensing rounds, a Strategic Environmental Impact Assessment (SEIA) for the region must be in place. The SEIAs are prepared by the Danish Centre for Environment and Energy (DCE) and the Greenland Institute of Natural Resources (GINR), on behalf of the Environmental Agency for Mineral Resource Activities (EAMRA) and can be found on the Government of Greenland's website (Government of Greenland, 2021d). A SEIA describes the physical and biological environment, protected areas, endangered species, level of pollutants, etc., of an exploration area. The main purpose of a SEIA is to:

- Provide background knowledge about the area for the Government of Greenland (decision-makers)
- Show where more knowledge is needed to properly regulate the activities
- Serve as background knowledge for the companies that want to work in the area – particularly in their preparation of an EIA (Environmental Impact Assessment)

Evaluation of hydrocarbon activities

Before conducting hydrocarbon activities, a pre-scope of the activity must be sent to EAMRA. Based on the pre-scope, EAMRA evaluates the environmental impact of the activity, and decides if:

1) There is a risk of significant environmental impacts implying that an Environmental Impact Assessment (EIA) of the activity shall be prepared,
2) The environmental impacts will be minor/limited implying that an Environmental Mitigation Assessment (EMA) of the activity shall be prepared, or

3) The environmental impacts will be negligible e.g., similar to normal shipping implying that no specific environmental report (EIA or EMA) shall be prepared.

In an EIA, the company describes potential environmental impacts of the activity, the likelihood of impacts, the effect of the impacts, and how they will limit potential environmental impacts through the use of environmentally friendly technology, best practices and mitigating measures. The EIA must go through public consultation, and in the end, it has to be approved by the Government of Greenland.

An EMA can be perceived as a reduced EIA and shall only focus on the mitigation measures proposed for the activity. Exploration drillings will always require an EIA. Seismic surveys will, depending on the size, in many cases require an EMA.

A guide to pre-scope for offshore hydrocarbon activities can be found on the Government of Greenland's website (Government of Greenland, 2015).

6.2 General description of the environment in Greenland

As oil and gas activities in Greenland primarily will take place offshore, the description of the environment is of the offshore environment.

Biological environment

Large parts of Greenland are situated within the Arctic, and the biological properties there are typical for Arctic regions. They are characterised by low biodiversity, a relatively simple food web that only has a few levels from primary production to top predator, and key species that play an important role in the ecology of the region.

The southern part of Greenland is situated in a subarctic environment, with the biological properties being close to those of the arctic regions.

Sea ice

Sea ice and icebergs are an important factor in relation to oil and gas activities as it makes operation more complex. Large portions of the Greenlandic waters are covered with sea ice during some part of the year, and it differs a lot from region to region for how long the waters are covered with sea ice. The figure below displays the extent of the sea ice throughout the year. The maps are constructed by DMI and are based on data from 2000 to 2016.

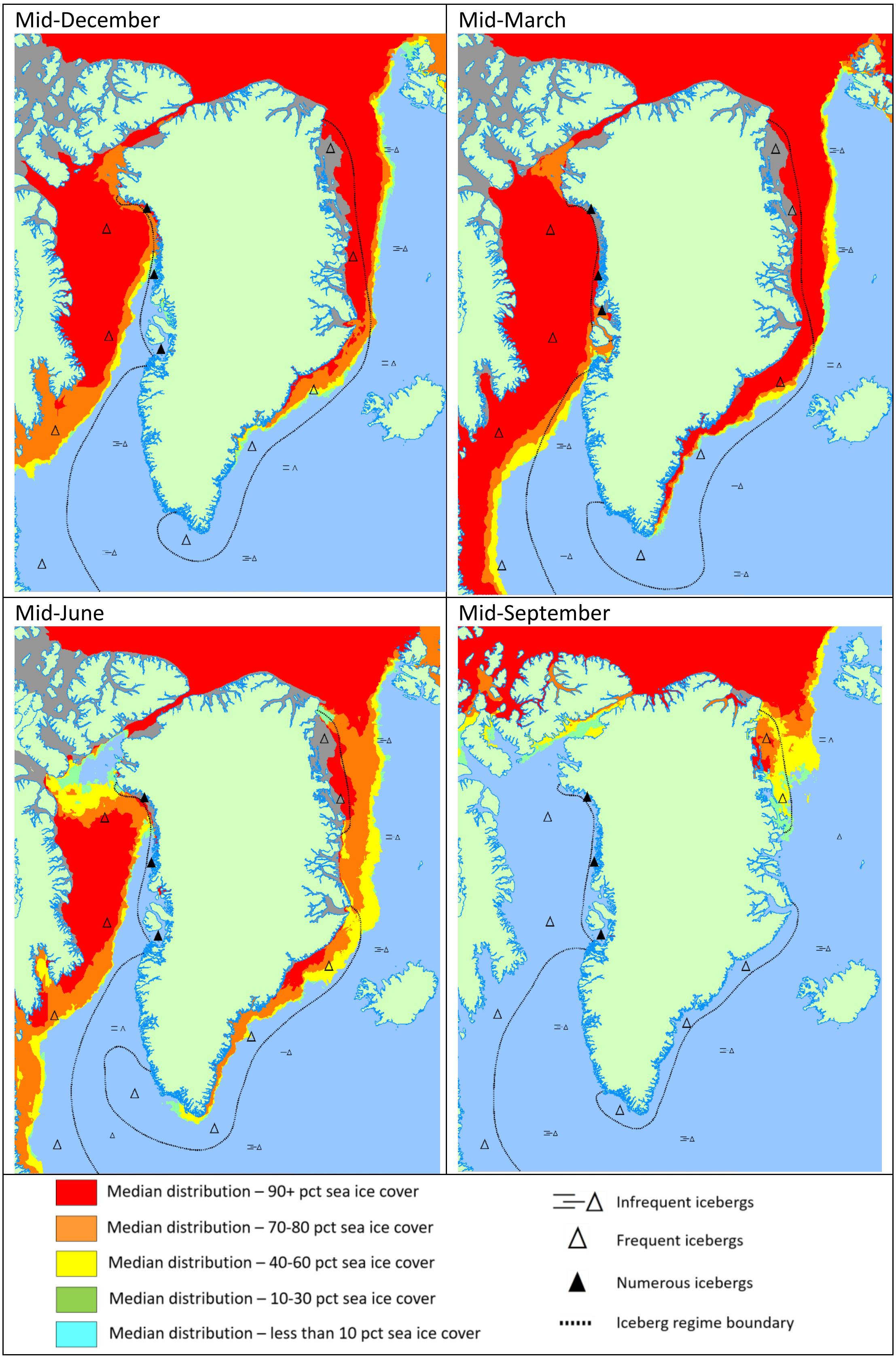


Figure 13: Median distribution of sea ice surrounding Greenland during different periods of the year

On the west coast the ice normally starts to build up in November/December, starting in the north. The maximum extents of the sea ice normally occur in March. The ice starts to break up from the southeast, and even in Baffin Bay you normally have some months without sea ice.

On the east coast the sea ice normally starts to build up in October – December and retrieves in July – September. In the northern part of the region, sea ice is normally present year-round.

The southern waters of Greenland are normally not affected by sea ice, but there are icebergs drifting down from northeast Greenlandic waters.

Sea ice conditions vary a lot through the years, but the general trend is a decrease in sea ice, as can be seen in Figure 14.

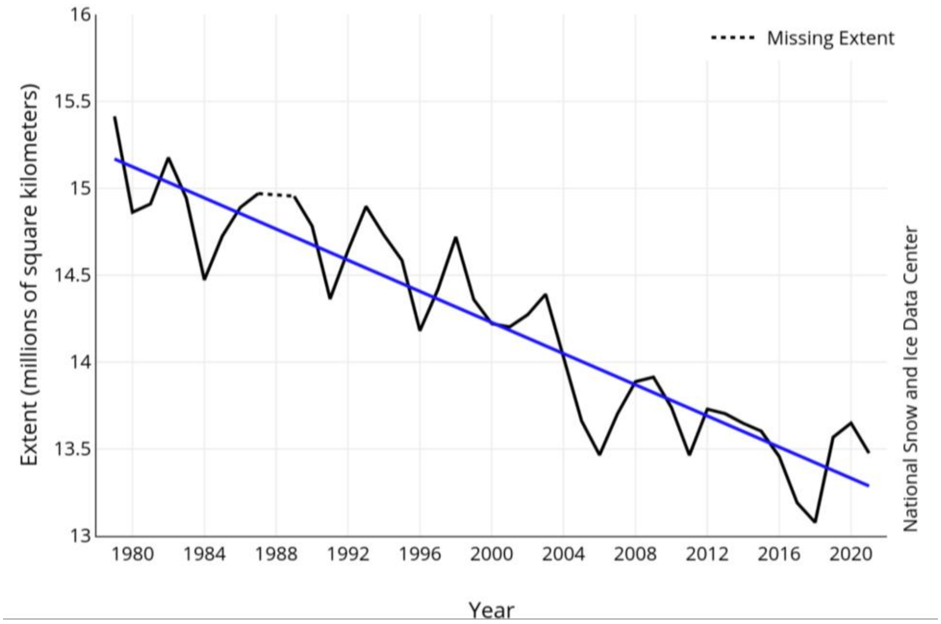


Figure 14: Monthly January Arctic sea ice extent from 1979 to 2021. App. 12% decrease over 40 years. Source: nsidc.org.

Meanwhile, Figure 15 below displays the findings from a 2011 DMI study which demonstrates how the number of ice-free days has increased in different areas of Greenland.

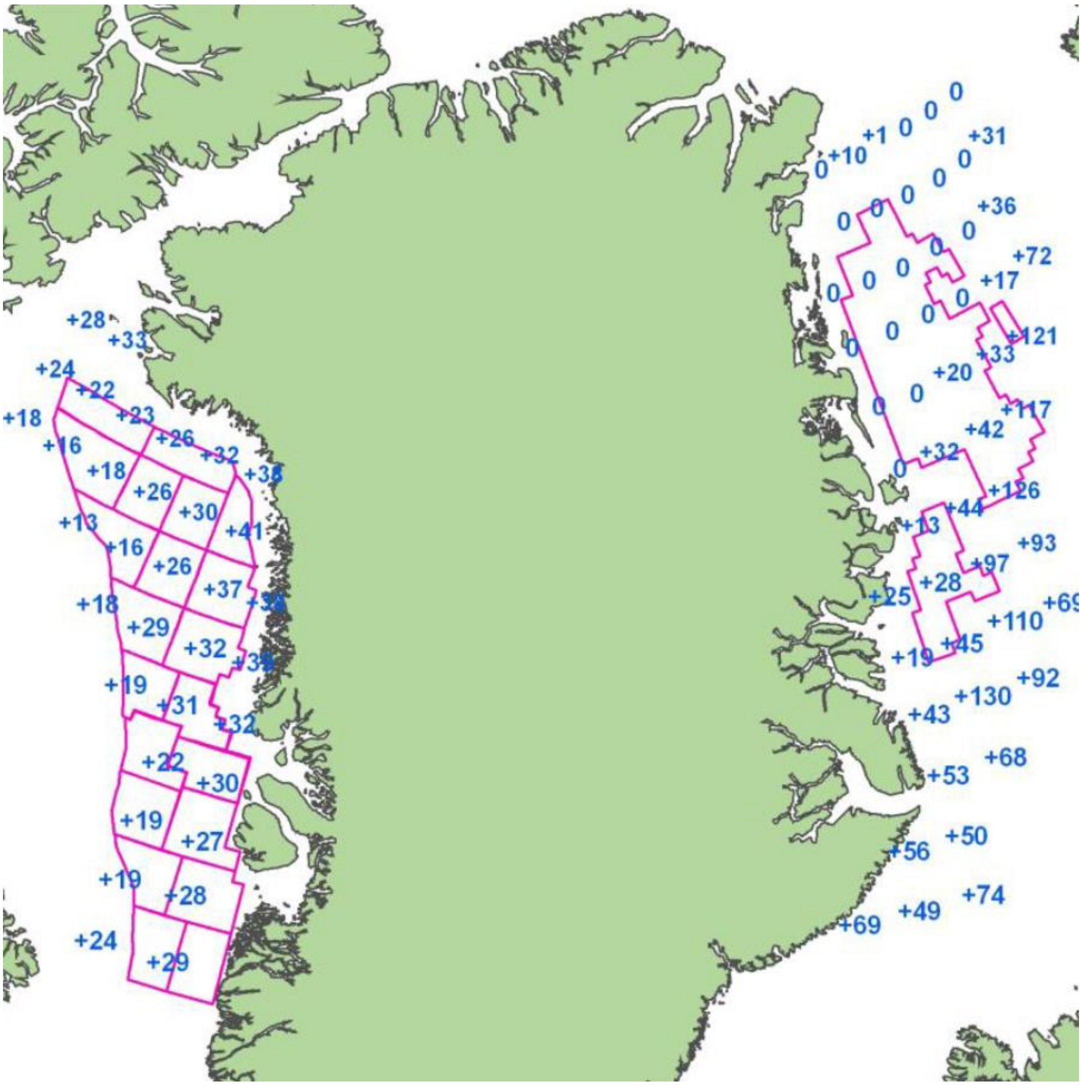


Figure 15: Difference in average number of ice-free days between the 2000-2010 period and the 1979-2010 period. In most areas in Baffin Bay the length of the ice-free period has increased by 2-4 weeks (15-30 days). Note that the west-coast numbers are average number of ice-free days whereas the east coast numbers are minimum numbers. Source: KANUMAS MET/ICE/OCEAN Overview Report 2011 Baffin Bay, DMI and DTU 2011.

6.3 Local effects from normal activities associated with hydrocarbon exploration and exploitation

The main environmental impact of hydrocarbon activities is related to noise, release of drilling mud and production water, and the placement of fixed structures. These effects can be mitigated by careful planning and by following best practices.

Generally speaking, exploration activities are temporary, and in areas with sea ice they will mainly take place during the ice-free season. Production activities on the other hand are long term and will take place all year.

The impacts listed below are all described in the different SEIAs.[7]

Noise

Noise is generated by seismic surveys, drilling activities, and ships and helicopters. The environmental impact from noise depends on the time of the noise, the area where the noise is generated, and the duration of the noise. Marine mammals and fish can be scared away by noise, but if the noise is temporary, they are likely to return shortly after the noisy activity stops. Seabirds might be affected by noise from helicopters.

Drilling mud and cuttings

Released drilling mud and cuttings will impact the benthic fauna. The impact will depend on the type of drilling mud, the location of the drilling, and the number of boreholes, but the impact can be mitigated by regulating the types of chemicals that are used. E.g., chemicals to be released in the Greenlandic environment must comply with OSPAR (HOCNF) standards.

Production water

Production water might impact the environment i.e., fish can be affected by the oil content in the water. The best way to mitigate these effects is to prohibit discharge (i.e., the produced water must be reinjected into old well bores), or alternatively to completely clean the water before release.

Fixed structures

Fixed structures might have both biological and aesthetic impacts. Depending on the structure and location it might impact local habitats or the tourist industry. The commercial fishery may also be affected by closure zones around rigs and pipelines.

6.4 Local effects from an accidental oil spill

By far the largest environmental impact from oil and gas exploration and exploitation would be from a large oil spill. Major oil spills in relation to oil exploration are most likely to happen as a result from a blowout during an exploration drilling or as spill from tankers.

A report from National Research Council (U.S. National Academy of Sciences) estimated that the total amount of oil spills worldwide from all known sources

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[7] The SEIA covering Baffin Bay can for example be found at: https://dce2.au.dk/pub/SR218.pdf

to constitute 1.3 million tonnes.[8] The primary sources according to the report are displayed in the table below.

Primary source of spill	
Natural seeps from the underground	46%
Operational spills from ships and onshore activities	37%
Spills from ships because of an accident	12%
Oil spill in relation to oil exploration/exploitation	3%
Other	2%

Table 9: Primary sources of global oil spills (U.S. National Academy of Sciences)

As the report outlines, oil spills from oil exploration are very rare and the oil industry has very high safety standards, especially when working in an arctic environment. A major oil spill in Greenland would have massive consequences for the environment, particularly in relation to the vulnerable flora and fauna found many places along the Greenlandic coast. One of the main challenges regarding a possible oil spill in Greenland is the very limited knowledge about clean-up of oil spills in ice filled waters.

Oil spill risk

As described above, oil spills from oil exploration are most likely to happen as a blowout from an exploration drilling or as a spill from tankers or other ships. More information on oil spills taken from the Strategic Environmental Impact Assessment for the Baffin Bay in Northwest Greenland is available in Annex 2.

Exploration drilling

Even though the risk of an oil spill from a blowout is very limited, the possible consequences from it would be exceedingly extensive. Greenland always requires that operators performing exploration drillings follow the highest international standards and take every possible step to avoid an accident. Exploration drillings will only take place during the ice-free season to minimise the risk of an oil spill in ice-filled waters.

Spill from tankers

During the exploitation phase the biggest risk would be spill from tankers. In contrast to exploration drillings, exploitation will happen all year round and

[8] Note that these numbers are from before the Macondo accident in the Mexican Gulf. This was a major accident, that has led to many changes regarding safety in the oil industry.

there is there for a risk that a spill from a tanker can happen during the winter with ice-filled waters.

6.5 Oil spill response in Greenland

The best way to protect the environment during exploration and exploitation is to prevent accidents from occurring. To do so, the operator must follow the rules and guidelines stated by the Government of Greenland. The Government of Greenland always follows the highest international standards including Best environmental practice (BEP) and Best available technology (BAT). This is not only in the best interest of the environment and the Greenlandic society, but also in the interest of the operator as it is their responsibility to avoid any accidents.

The operator must always have prepared contingency plans in case of any accidents. During any operations it is also required of the operator that a subscription to Greenland Oil Spill Response (gosr.gl) is undertaken.

More information on oil response is available in Annex 2.

6.6 Global effects – climate change

The Paris Agreement is a legally binding international treaty on climate change adopted by 196 Parties at COP 21 in Paris, on December 12th, 2015, and entered into force on November 4th, 2016 (IPCC).

The goal is to limit global warming to well below 2, preferably to 1.5 degrees Celsius, compared to pre-industrial levels. To achieve this long-term temperature goal, countries aim to reach global peaking of greenhouse gas emissions as soon as possible to achieve a climate neutral world by mid-century.

The global anthropogenic (human induced) emissions of CO_2 passed 40 bio tons CO_2 in 2019 (IPCC). CO_2 is the most important climate gas, and emissions of CO_2 from fossil fuels is the source of approximately two thirds of the human induced climate warming effect.

Based on a global oil consumption of app 100 bbl./day in 2019 (EIA), the direct CO_2 emission from burning oil in non-petrochemical sectors can be calculated to 14.4 billion tonnes CO_2, one third of global emissions. In addition to this, several studies indicate that oil and gas extraction, processing, and the subsequent transport of oil and oil products to end-users increases the total carbon footprint of oil by 15%-20%. According to several studies, there are a number of options available to reduce these upstream emissions. One of the most cost-effective options is to limit methane emissions from oil and gas operations.

7 Global oil demand, prices and policies

Since the oil crises of the 1970s, the global demand for oil has increased steadily by an average of 1.5% a year up to the current level of approximately 100 bio bbl/day. Today oil makes up 30% of global primary energy supply, a role that is expected to slowly decrease over the coming years.

Previously there was concern that a depletion of global oil resources would be a main trigger for the need for alternatives to oil. In recent years however, new finds have been able to keep reserves at a reasonably steady level, and in many countries, concerns have shifted more towards climate policy with development and deployment of energy efficiency and renewable energy policies than policies aiming at security of supply for oil. As can be seen in this chapter, these shifting policies also affect the long-term projection of oil prices developed by the International Energy Agency and other institutions.

7.1 Historic global supply/demand and prices

Global oil demand

During the last half century, the demand for oil has grown significantly, from roughly 100 EJ (just under 2,400 million tonnes) in 1971, to over 187 EJ (4,475 Mt) in 2019. Except for a few drops in the early 1980s, and as a result of the financial crisis in 2008 and 2009, global oil demand has grown steadily over these 50 years. The development in global oil demand from 1971 to 2019 is displayed in Figure 16. As oil demand is often discussed in various terms, the figure displays the results in both EJ (left axis) and Mt (right axis).

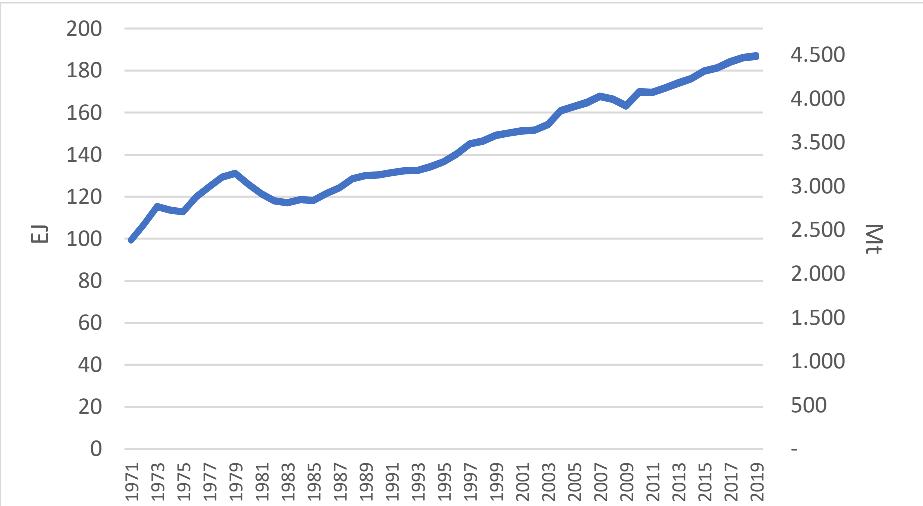

Figure 16: Development in global demand for oil from 1971 to 2019 in EJ on the left axis, and millions of tonnes (Mt) on the right axis. (IEA, 2020b)

As oil production is also often expressed in millions of barrels per day, the following figure displays the historic global oil production by region in millions of barrels per day.

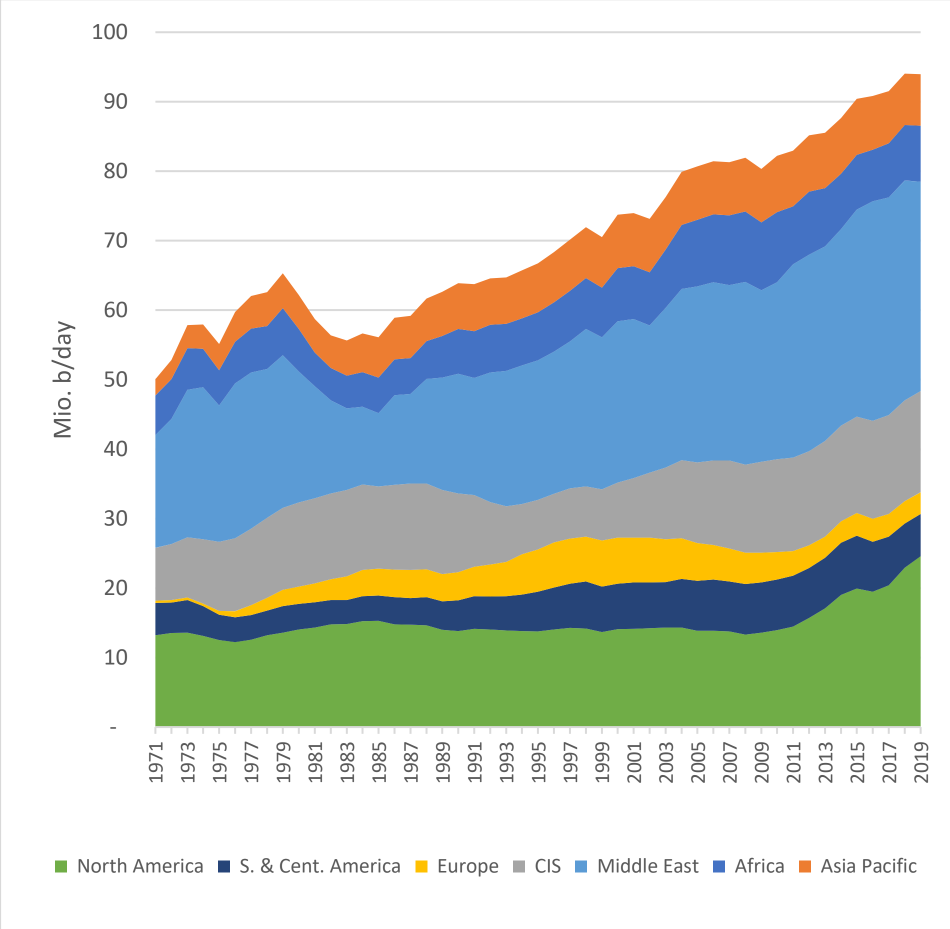

Figure 17: Development in historic oil production by region from 1971 to 2019 in millions of barrels per day. (BP, 2020c)

Brent oil price

While the demand for oil has historically grown at a fairly steady rate, the same cannot be said for the development in the price for oil. This is highlighted in Figure 18 below, which displays the historic monthly Brent oil price per barrel in both nominal, and 2020, USD terms since 1987. Unless otherwise stated, throughout the remainder of the report, prices will be stated in real terms, i.e. 2020 USD.

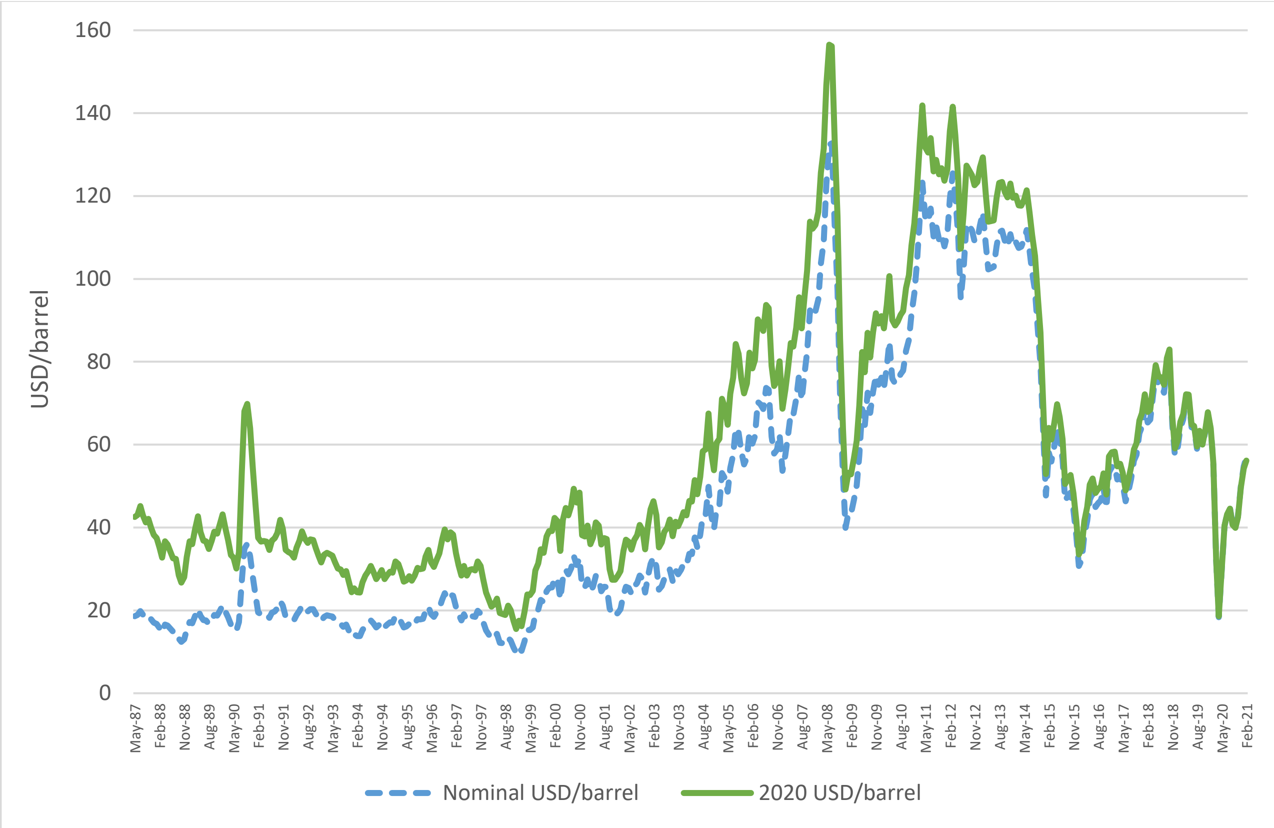

Figure 18: Historic (1987-2021) average monthly price per barrel of brent crude in nominal (blue striped line) and real terms 2020 USD) (green solid line (EIA, 2021a)*. Note that the price for February of 2021 is based only on the first 3 weeks.*

From 1987 until the early 2000s, the monthly oil price averaged roughly $34 per barrel, and was usually within +/- $5 of this average. All of this changed in 2003 when the first stage of the Iraq war started, and oil prices increased significantly until the middle of 2008 (peaking at over $150), at which point a sharp decline in oil demand due to the financial crisis resulted in oil prices falling to under a third of their previous high by December of the same year. Prices were under $60 for only a few months before once again increasing significantly. Starting in October of 2010, this led to a period of over 4 years with average monthly prices over $100/barrel (and often in the 120-140 range). During this time, the feeling amongst some oil experts and commentators was that oil prices were unlikely to fall below $100/barrel for a decade or more (Khrennikova, 2013), while the general consensus indicated oil prices between $80-90/barrel.

In 2014 however, the global supply of oil started to outpace global demand, and as a result, prices fell very sharply. One of the main reasons for this was the oil and shale gas 'revolution' occurring in the United States. Here, new fracking technologies and methods were allowing for largescale and very quick ramping up of oil and gas production. The figure below highlights how the advent of oil production via fracking allowed the United States to reverse a longstanding trend of falling US production and growing net imports of oil. In fact, during a period of less than 3.5 years, from mid-2011 to the start of 2015, average daily production of oil in the US increased from less than 5.5 million b/day to over 9.5 million b/day.

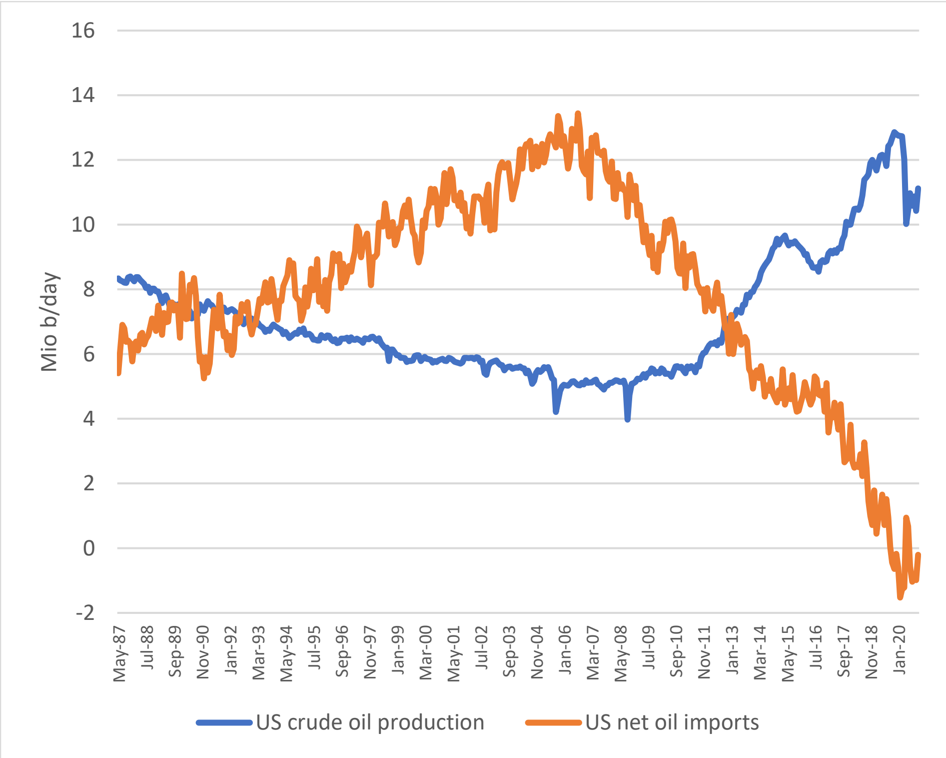

Figure 19: Historic US oil production and net imports in millions of barrels per day. (EIA, 2021c) (EIA, 2021b)

Returning to the discussion of global oil prices, since the start of 2015, the price of Brent crude has averaged roughly $57/barrel, with short periods of average monthly prices above $75/barrel or below $40/barrel.

7.2 Overview of global policies on oil exploration

In recent times, there has been growing attention on the funding of exploration and development of fossil fuels, as part of a growing consensus surrounding the necessity of a swift green transition.

Besides major energy companies advocating for an increasing diversification of their portfolio (see section 7.2), the finance industry is also facing renewed scrutiny from the public in their role as financers of climate change.

Financial institutions

In this respect, there are several financial institutions that have issued voluntary policy statements limiting their exposure to fossil investments. Some of these institutions (which include the USA's five largest banks) have made specific reference to the exploration and development of Arctic oil and gas (Oil World, 2020). Table 10 summarises the environmental policies of selected banks, including the USA's top 5 banks.

Financial Institution	Policy Statement on the Arctic	Latest update
Morgan Stanley	Transactions will require senior management approval, will not finance new oil and gas exploration and development, enhanced due diligence	December 2020
Citicorp	Will not provide project-related financial services for oil and gas exploration, development and production	July 2020
Goldman Sachs	Enhanced due diligence including understanding companies' strategy and commitment to reducing overall GHG emissions, will decline any financing transaction that directly supports new upstream oil exploration or development	December 2019
JPMorgan Chase	Will not provide project financing or other forms of asset-specific financing where the proceeds will be used for upstream, midstream or downstream greenfield oil and gas development in the Arctic	February 2020
Wells Fargo	For clients that have operations in Alaska/Arctic, due diligence addresses stakeholder engagement, including indigenous peoples of Alaska, ecosystems and biodiversity as well as region-specific water risks, follows Equator Principles	June 2018
Bank of America	Will not knowingly engage in direct financing of petroleum exploration in the Arctic	February 2021
Deutsche Bank	Will not finance new oil and gas projects in the Arctic region	July 2020

Table 10: Environmental policies towards the Arctic of selected banks (including USA's top 5). Source: Bank's websites

However, these policies have not been welcomed by all sectors, as e.g., the Trump administration ultimately succeeded to limit the industry's initiative before leaving office. In this respect, the US Office of the Comptroller of the Currency (OCC) adopted in January 2021, a rule ensuring that prohibits banks from denying any person a financial service unless there is a justification based on "impartial, risk-based standards" (CNBC, 2021; Lofchie, 2021).

However, the extent to which such industry self-regulations will impact actual financing of Arctic oil and gas activity still is uncertain. In the same way, the extent to which the recently approved government regulation will succeed is also uncertain, as there will be pressure from the lenders' side.

Evidence shows that, after the Paris Agreement was signed in 2015, energy companies have continued to receive financing anyway. Whether this has been geared towards green energy or to fossil fuel investments is, of course, debatable. Figure 20Figure 21Figure 22 show the financing sources of some of the energy companies with energy investments in the Arctic.

The amounts shown refer to transactions covering lending and underwriting of shares and bonds, but excludes direct investment, for example in the form of direct holding of shares, which can be relevant for some companies, such as Italy's Eni, where the Italian investment bank cdp owns 26% of shares.

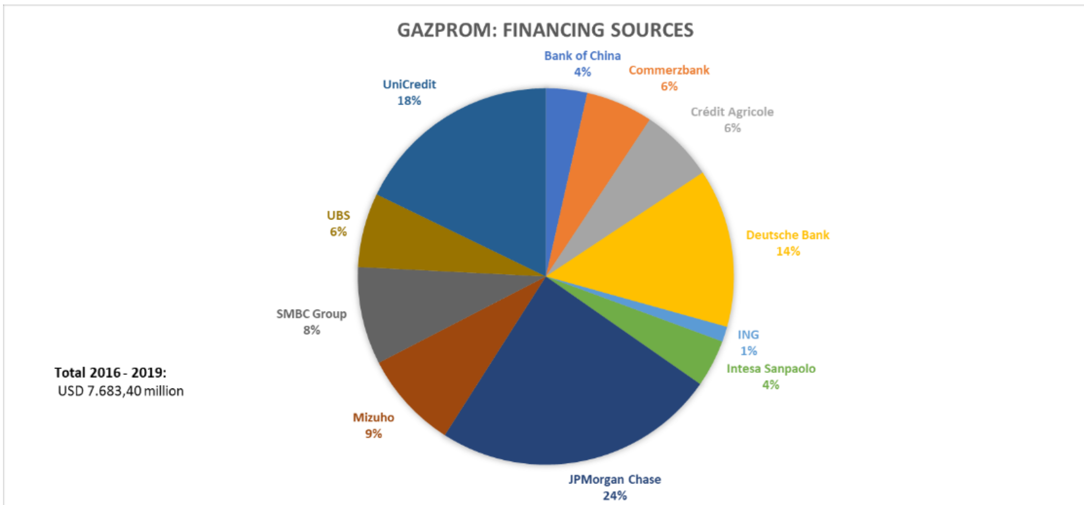

Figure 20: Gazprom financing sources and amount in the period 2016-2019. Source: (Oilchange et al., 2020) *with data provided by Bloomberg's League tables*

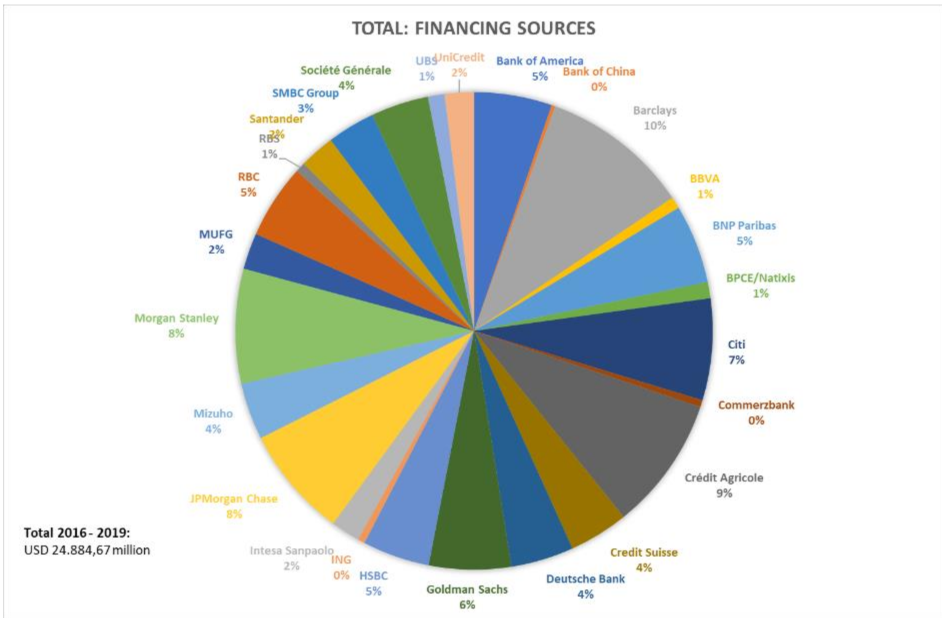

Figure 21: Total's financing sources and amount in the period 2016-2019. Source: (Oilchange et al., 2020) *with data provided by Bloomberg's League tables*

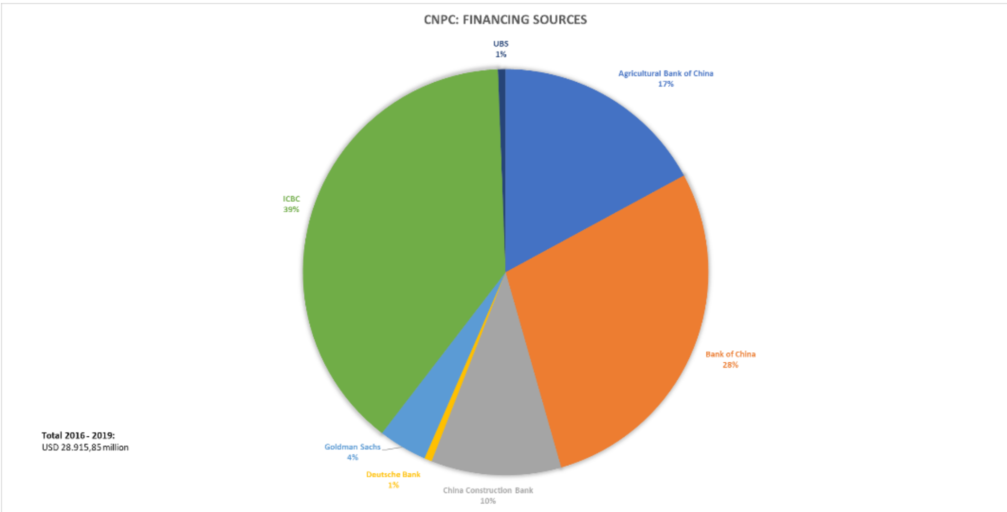

Figure 22: CNPC's financing sources and amount in the period 2016-2019. Source: (Oilchange et al., 2020) *with data provided by Bloomberg's League tables*

Pension funds

Another interesting debate currently ongoing in Denmark is whether the Danish pension fund should continue to invest in fossil fuels. Once again, the Danish pension fund is not amongst the largest pension funds in the world, but this debate is not only taking place in Denmark. It should be noted that the arguments put forward for shifting away investments from fossil fuels are not strictly due to an urge to reduce greenhouse gas emissions, but there is also a growing argumentation that the potential risk of stranded assets associated with fossil fuel investments could reduce the returns on such assets relative to green energy investments.

Danish Government

Though not a major oil and production nation, Denmark is one of the few European countries that is a net exporter of oil and gas. Thus, it was noteworthy when in December of 2020, the Danish parliament announced an end-date for oil and gas production in the North Sea of 2050, and the cancellation of the 8th (and any future) tender round(s) for future oil and gas licences. The parliament recognised that this decision would result in foregone revenues, which were estimated (with a rather high level of uncertainty) at 13 billion DKK. (Danish Parliament, 2020).

British Petroleum (BP)

The ongoing discussion regarding the green transition, and the role that energy companies can play in it is rather complex, and energy companies have widely diverging strategies. For example, some oil companies are largely continuing with business as usual and continuing to focus on their core competencies, while others such as British Petroleum (BP) are signalling a large strategic shift.

During 2020, BP announced a long-term aim of nearly net-zero CO_2 emissions by 2050, and later released more specific aspects of this goal, including:

- Reducing oil and gas production in 2030 to roughly 1.5 million boe/day, which is roughly a 40% reduction from 2019 levels of 2.6 million boe/day.
- A reduction in refining operations, from 1.7 million b/d today, to 1.2 million b/d in 2030. (Johnson, 2020).

7.3 Future global supply/demand and prices

Forecasting future energy prices such as oil is a complicated endeavour, with numerous underlying assumptions affecting the forecasted prices. As a result, diverse actors, utilising varying methodologies and assumptions, can arrive at widely diverging results. The following section includes future potential oil prices from international agencies, energy companies, market actors, and private consultants. The section concludes with Ea's assessment of which price forecasts (or combination thereof) to utilise in estimating future potential oil prices in the current analysis.

International Energy Agency

One of the primary actors that models future potential energy prices is the International Energy Agency (IEA). The IEA's flagship publication is its annual

World Energy Outlook (WEO), which includes a few primary scenarios resulting in future energy prices. The World Energy Model (WEM), the main tool used in the development of the IEA WEO scenario projections, operates under the assumptions of long-term equilibrium, and therefore generally does not reflect minor short-term price fluctuations. The three main scenarios, along with a supplemental 4th scenario, in the 2020 WEO are the:

- Stated Policies Scenario (STEPS)
- Delayed Recovery Scenario (DRS)
- Sustainable Development Scenario (SDS)
- Net Zero Emissions by 2050 case (NZE2050)

More detailed descriptions of the 4 scenarios taken directly from the 2020 WEO are displayed in the below text box (Cozzi et al., 2020).

2020 WEO Scenarios

*"The **Stated Policies Scenario (STEPS)** assumes that significant risks to public health are brought under control over the course of 2021, allowing for a steady recovery in economic activity. This scenario incorporates our assessment of all the policy ambitions and targets that have been legislated for or announced by governments around the world.*

*The **Delayed Recovery Scenario (DRS)** retains the initial policy assumptions of the STEPS but takes a more pessimistic view on the outlook for public health and for the economy. In this scenario, a prolonged pandemic has deeper and longer lasting impacts on a range of economic, social and energy indicators than is the case in the STEPS.*

*The **Sustainable Development Scenario (SDS**) is based on the same economic and public health outlook as the STEPS, but works backwards from climate, clean air, and energy access goals, examining what actions would be necessary to achieve those goals. The near-term detail is drawn from the recent IEA Sustainable Recovery Plan, which boosts economies and employment while building cleaner and more resilient energy systems (IEA, 2020a).*

*The **Net Zero Emissions by 2050 case (NZE2050)** supplements the SDS analysis. The SDS sees many advanced economies reaching net-zero emissions by 2050 at the latest and puts the world on track for net-zero emissions by 2070. The NZE2050 includes the first detailed IEA modelling of what would be needed over the next ten years to put CO_2 emissions on a pathway to net-zero emissions globally by 2050." (Cozzi et al., 2020).*

Forecasted oil demand through to 2040 in the STEPS and the DRS are displayed in the figure below. Note that the development for the SDS is not included, but it is roughly 66 mb/d in 2040, and therefore is considerably lower than today.

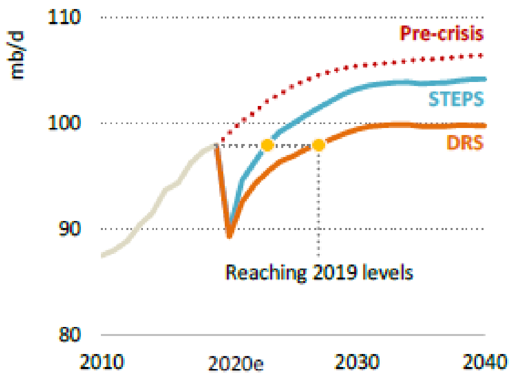

Figure 23: Oil demand in the STEPS and DRS. Note that the development for the SDS is not included, but it is roughly 66 mb/d in 2040. (Cozzi et al., 2020)

The oil prices for specific years according to the various WEO scenarios are displayed in Table 11.

Scenario	2020	2025	2030	2035	2040
Stated Policies		71.9	76.9	82.0	86.0
Delayed Recovery	63.8	59.7	N/A	N/A	72.9
Sustainable Development		57.7	N/A	N/A	53.6

Table 11: Future oil prices in specific years (in 2020 USD/barrel) according to WEO scenario.(Cozzi et al., 2020)

There is a large difference in future oil prices depending on the envisioned scenario. In the stated policies scenario, oil prices continue to increase from today to 2040, from $64 to $86 per barrel. Meanwhile, in the Sustainable Development scenario, prices are instead forecasted to be in the mid to low $50s.

EIA

Each year the U.S. Energy Information Administration publishes its "Annual Energy Outlook" (AEO), with the latest edition being published in January of 2020. The EIA utilises an integrated model, the National Energy Modelling System, to develop the annual Outlook. The outlook has a reference case, along with several other cases. According to the Outlook, the key aspects of the reference case are that:

- *"It Represents EIA's best assessment of how U.S. and world energy markets will operate through 2050, based on key assumptions intended to provide a base for exploring long-term trends"*
- *It should be interpreted as a reasonable baseline case that can be compared with the cases that include alternative assumptions.*

- *It generally assumes that current laws and regulations that affect the energy sector, including laws that have end dates, are unchanged throughout the projection period. This assumption makes it possible for us to use the Reference case as a benchmark to compare policy-based modelling*
- *The potential effects of proposed legislation, regulations, or standards are not included in the AEO2020 cases."* (EIA, 2020)

In reviewing the AEO forecasts, the last two points above should be kept in mind. I.e., that the effects of new legislation, regulation or standards are not incorporated, and in this sense the forecast represents a "Frozen Policy" situation. Given that a new administration was sworn in just over a year after the outlook was released, this could have profound effects on new and expected energy policies, and it will therefore be interesting to see how the 2021 and 2022 AEO forecasts differ from the 2020 version.

According to the Outlook, the key aspects of the sides case are that:

- *"Future oil prices are highly uncertain and are subject to international market conditions influenced by factors outside of the National Energy Modelling System.*
- *The High Oil Price and Low Oil Price cases represent international conditions that could drive prices to extreme, sustained deviations from the Reference case price path"* (EIA, 2020).

The forecasted North Sea Brent Crude price in 2019 USD per barrel for the various scenarios is displayed in Figure 24.

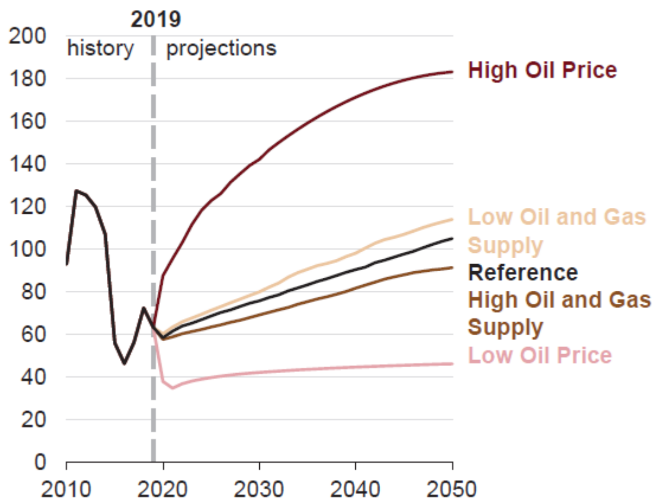

Figure 24: Forecasted North Sea Brent Crude price in 2019 USD per barrel (EIA, 2020)

OPEC

Each year since 2007 the Organisation of the Petroleum Exporting countries (OPEC) has published its World Oil Outlook (WOO), and the most recent version was published in October of 2020.

The 2020 edition of the WOO does not include any price projections for oil, but in reviewing the long-term oil demand prognosis, the main takeaway is an assumed plateauing of oil demand in the mid-late 2030s.

	2019	2020	2025	2030	2035	2040	2045	Growth 2019–2045
OECD Americas	25.6	23.3	25.7	24.8	23.1	21.2	19.3	–6.3
OECD Europe	14.3	12.6	13.7	12.9	12.0	11.1	10.2	–4.1
OECD Asia Oceania	7.9	7.1	7.4	6.9	6.4	5.8	5.2	–2.7
OECD	**47.9**	**43.0**	**46.8**	**44.6**	**41.5**	**38.0**	**34.8**	**–13.1**
Latin America	6.2	5.8	6.6	7.1	7.4	7.6	7.9	1.6
Middle East & Africa	4.3	3.9	4.8	5.5	6.2	6.9	7.6	3.3
India	4.8	4.3	5.8	7.2	8.6	9.9	11.1	6.3
China	13.1	12.1	14.4	15.5	16.2	16.7	17.1	4.0
Other Asia	9.0	8.5	9.9	10.9	11.7	12.4	13.0	3.9
OPEC	8.7	8.2	9.5	10.5	11.3	11.7	11.7	3.0
Russia	3.6	3.2	3.7	3.8	3.8	3.8	3.7	0.1
Other Eurasia	2.0	1.8	2.1	2.2	2.3	2.3	2.3	0.2
Non-OECD	**51.8**	**47.8**	**56.9**	**62.6**	**67.4**	**71.2**	**74.3**	**22.5**
World	**99.7**	**90.7**	**103.7**	**107.2**	**108.9**	**109.3**	**109.1**	**9.4**

Figure 25: Long-term oil demand by region in the reference case (mb/d) (OPEC, 2020)

The OPEC publication also has another scenario, dubbed the Accelerated Policy and Technology Case (APT Case). According to the publication, it:

> *"Has been developed to assess potential implications on future oil demand if additional policy measures across all major consumption sectors were adopted, allowing (and supporting) the faster penetration of more efficient technologies. It is important to note that this case does not assume any major technological breakthroughs. It simply explores the potential for a reasonably faster penetration of existing technology that could be achieved at reasonable cost if adequate incentives were put in place."* (OPEC, 2020)

As can be seen from the figure below however, oil demand in APT CASE does not differ considerably from the primary scenario.

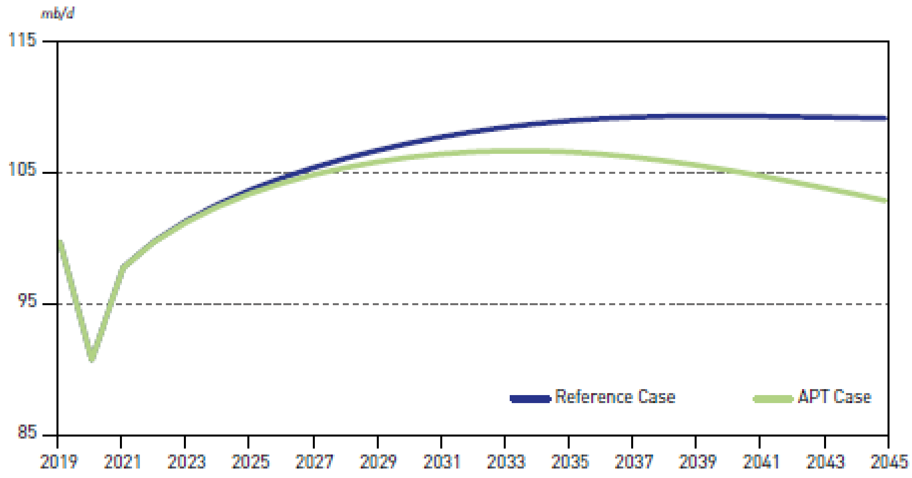

Figure 26: Oil demand in the Reference and APT cases.(OPEC, 2020)

DNV GL

DNV GL describes itself as a global quality assurance and risk management company, and amongst other things, a technical advisor to the oil and gas industry (DNV GL, 2021). DNV GL has been publishing an Energy Transition Outlook annually since 2017, and the latest version was the 2020 edition.

In reviewing the oil demand forecasts from the DNV GL publications, the contrast with IEA Stated Polices, or OPEC scenarios, above is quite startling. In the DNV GL forecast, global oil demand has already peaked, and by 2040 be back too mid-1980 levels.

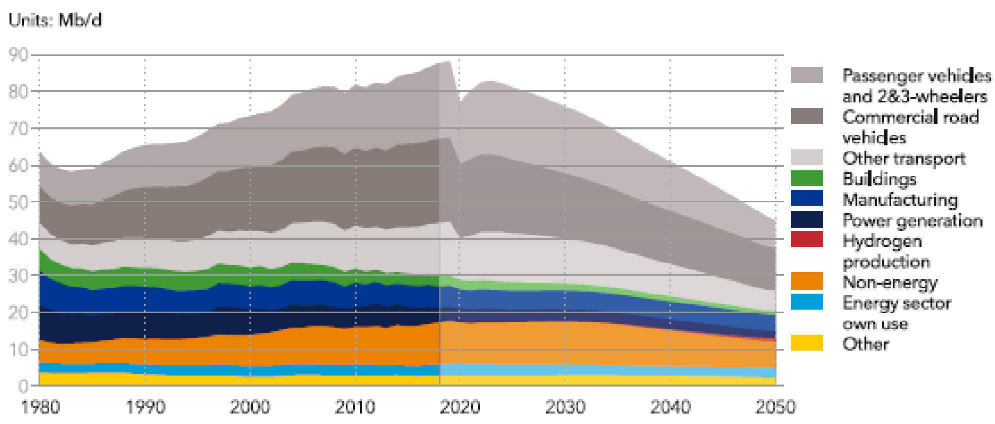

Figure 27: World oil demand forecast in the 2020 DNV GL Energy Transition Outlook. Note that it does not include natural gas liquids and bioliquids. (DNV GL, 2020)

Energy companies

ExxonMobil, in its most recent Outlook for Energy which looks towards 2040, underscores the continuing increase in energy, electricity, and transport demand, and that oil and gas will remain import energy sources that require significant investment (ExxonMobil, 2020). The energy demand projection from the report is displayed in Figure 28.

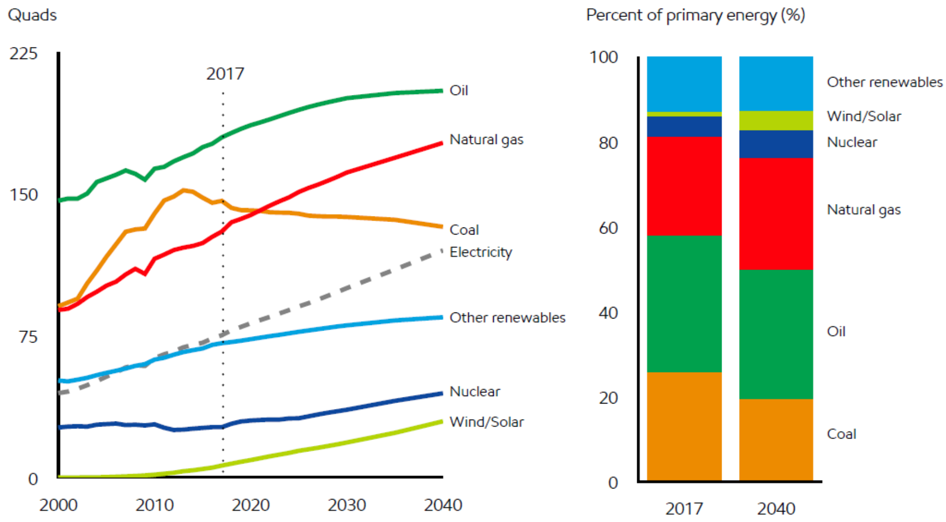

Figure 28: Global energy demand projects (note that 1 Quad is roughly 1.055 EJ).(ExxonMobil, 2020)

The development in oil and gas demand are very similar to those found in the Stated Policies Scenario of the 2020 WEO, which is not surprising given that the ExxonMobil report states that it uses IEA sources as a foundation for projecting energy demand.

Another of the world's largest oil companies, BP has a different view on the development of oil demand. Similar to DNV GL, BP foresees the demand for oil peaking in the mid- to late-2020s. In September of 2020, BP launched its Energy Outlook 2020, in which 3 scenarios explore the energy transition to 2050. According to BP's website, the scenarios are not "predictions of what is likely to happen or what bp would like to happen. Rather, the scenarios help to illustrate the range of outcomes possible over the next thirty years…" (BP, 2020b). The three scenarios are:

- *"**The Rapid Transition Scenario** (Rapid) posits a series of policy measures, led by a significant increase in carbon prices and supported by more-targeted sector specific measures, which cause carbon emissions from energy use to fall by around 70% by 2050. This fall in emissions is in line with scenarios which are consistent with limiting the rise in global temperatures by 2100 to well below 2-degrees Celsius above pre-industrial levels.*
- ***The Net Zero Scenario** (Net Zero) assumes that the policy measures embodied in Rapid are both added to and reinforced by significant shifts in societal behaviour and preferences, which further accelerate*

the reduction in carbon emissions. Global carbon emissions from energy use fall by over 95% by 2050, broadly in line with a range of scenarios which are consistent with limiting temperature rises to 1.5-degrees Celsius.

- ***The Business-as-usual Scenario*** *(BAU) assumes that government policies, technologies and social preferences continue to evolve in a manner and speed seen over the recent past*. A continuation of that progress, albeit relatively slow, means carbon emissions peak in the mid-2020s. Despite this peaking, little headway is made in terms of reducing carbon emissions from energy use, with emissions in 2050 less than 10% below 2018 levels."*(BP, 2020b)

The development in liquid fuel demand (primarily oil, but also biofuels and other liquids), for these scenarios is displayed in the figure below.

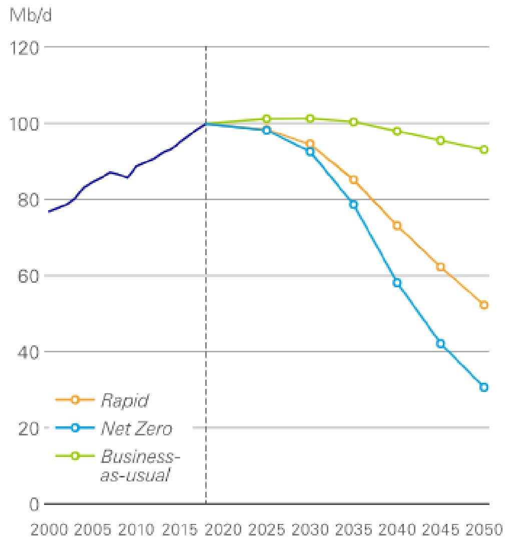

Figure 29: Development in liquid fuel demand (primarily oil, but also biofuels and other liquids), in the three BP scenarios in the 2020 Energy Outlook.(BP, 2020a)

As can be seen from the figure, even in the business-as-usual scenario, the demand for oil peaks in the mid- to late-2020s, a development path that is in stark contrast with ExxonMobil above.

Prominent consulting companies

In a 2020 publication by McKinsey & Company, the authors stated that there were likely to be long-term challenges for the oil and gas industry (Barbosa et al., 2020). Firstly, they stated that they expected growth in demand for hydrocarbons, particularly oil, to peak in the 2030s, before starting to decline. The authors conclude that this fall in demand, driven by the green energy transition, coupled with the shale oil and gas subsector's continued ability to bring additional supply on quickly in the face of high prices, will make it difficult for OPEC to maintain high oil prices. Other challenges noted were excess refining capacity, which will also place pressure on profits. (Barbosa et al., 2020).

Selected long-term forecasts

Given the extensive work that goes into the International Energy Agency's WEO scenarios, and the ability to view and dissect many of the assumptions underlying the scenario results, they have been assessed to present the best point of departure for use in estimating future potential oil prices in the current analysis.

Short to medium term market-based price estimates

In the short/medium- term, it is reasonable to assume that price projections based on the best available actual market information (likely incorporating the price effects of short-term market distortions and/or cyclicality) are more representative. Forward and future financial contract prices express the market actor's willingness (and commitment) to pay for the commodities in question at a predefined future point in time. It is fair to assume that the prices of these financial contracts have been set based on the best currently available information, and, as such, serve as an indication of the best estimate of future price expectations shared among the market participants.

Given the timeframe of any potential oil development projects in Greenland, i.e., completion date of 2030 at the very earliest, forward and future financial contract prices only available until 2028 are unlikely to affect the relevant long-term price estimates, but they are included below to give a sense of how market actors anticipate oil prices will develop in the short/medium term. For more on how Ea converges between these short/medium term prices and long-term price forecasts, please see Annex 3.

Previous IEA scenarios and forecasting

Before turning to the assessment of which WEO scenario prices to utilise in the current analysis, it is relevant to review:

- How the same scenario price forecasts have developed over time,
- The IEA's historical ability to forecast the shift from fossil fuels to renewable energy.

Development in price forecasts over time

As the IEA WEO has been published on a regular basis with a standard methodology for many years it is quite suitable for assessing how scenario prices have developed over time, and how current prices at the time of the forecast impacted the price predictions.

Numerous oil forecasts from the main scenario in the WEO publications since 1994, along with the historical IEA crude oil prices, are displayed in Figure 30.

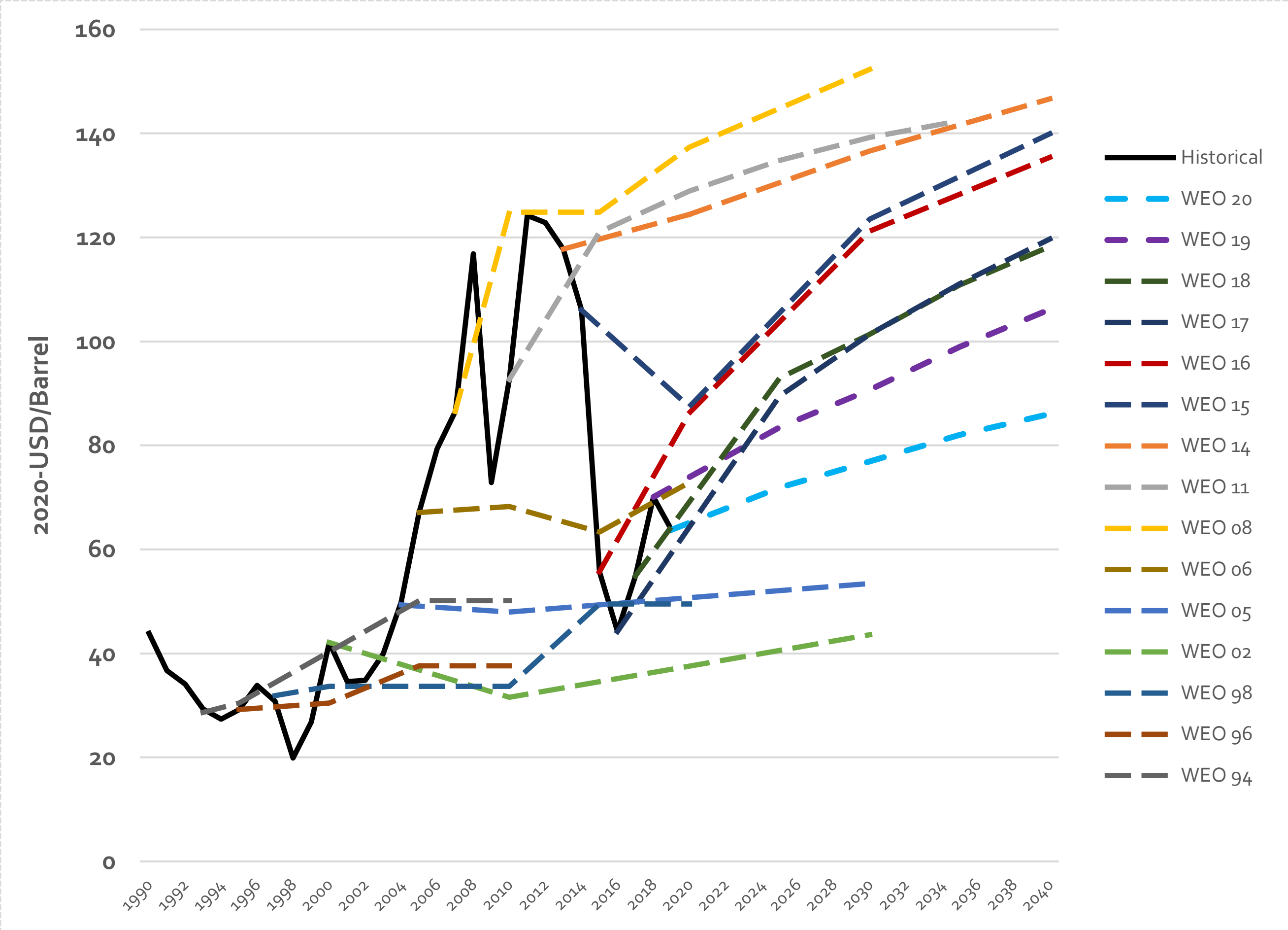

Figure 30: Comparison of oil price forecasts from previous WEO Stated policies scenarios (2020 USD/barrel).

It is evident from the figure that the price level at the time of the publication is extremely relevant for the future price forecasts. Prior to 2004, when the average annual oil price had not been over $40 for more than a decade, none of the WEOs predicted a future oil price over $45. However, as oil prices started to increase rapidly from 2005 to mid-2008, the WEOs in these years also started to forecast much higher future prices.

More recently, it is interesting to note that every WEO Stated Policy scenario since 2014 has forecasted a lower oil price for 2040 than the year previously, despite the fact that the oil prices at the time were higher in 2018 and 2017 then had been the year previously. This evolution is illustrated in Figure 31.

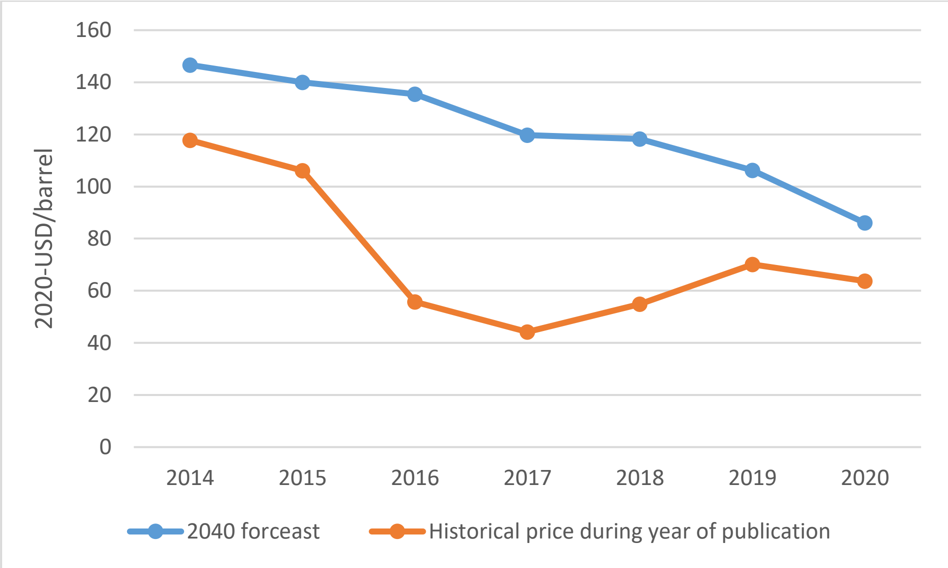

Figure 31: Forecasted oil price in 2040 in the Stated Policies scenario of the WEOs from 2014 to 2020 (blue line), and historical price during year of publication. All prices in 2020-USD/barrel.

This trend could signal a shift from the importance of the current oil price to a long-term understanding that a growing number of countries are indicating a shift away from oil towards 2040 and beyond.

Forecasting the shift to renewables

The IEA's annual WEO is seen as a flagship publication and is undoubtedly one of the most comprehensive publications on global energy scenario modelling that is currently undertaken. However, one valid critique of the IEA's work is that the central scenario has consistently underestimated the development pace of renewables, particularly in terms of technology cost reduction for solar and wind, and also the pace at which these technologies have replaced fossil-fuel-based electricity generation. Ea has followed these developments closely over the years, and as a result, has turned to employing the sustainable development scenario as its primary reference scenario.

Analysis of 2020 WEO scenario assumptions

The most important factor in determining the future oil price is the demand for oil. The figure below displays the oil demand according to sector in the Stated Polices and Sustainable Development scenarios of the 2020 WEO.

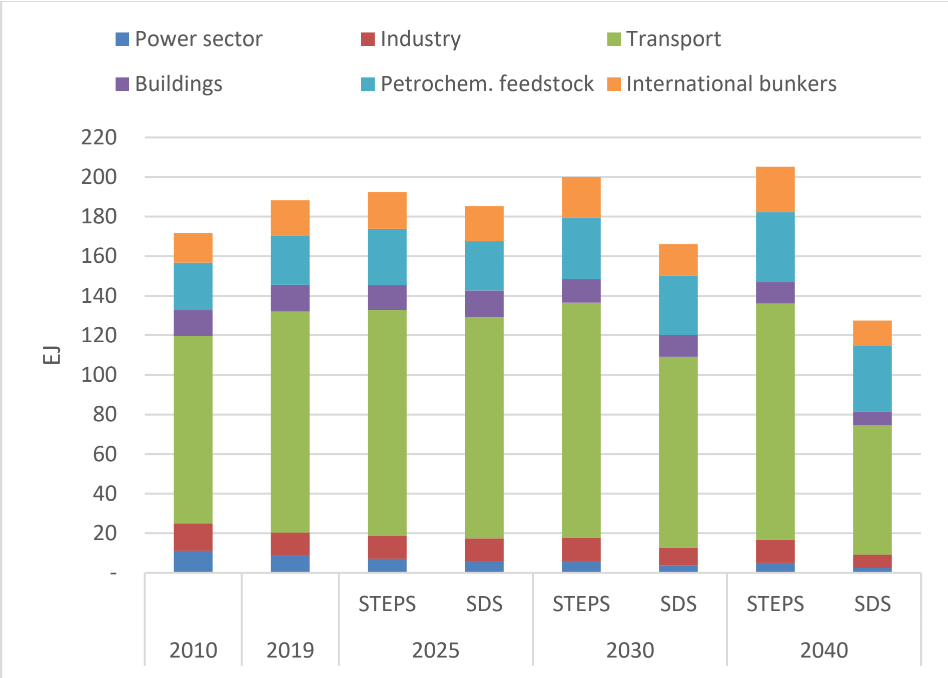

Figure 32: Historic and project global demand for oil (EJ) in the Stated Polices (STEPS), and Sustainable Development (SDS) scenarios from the 2020 IEA WEO.

In estimating future global demand for oil, the point of the departure was the above figure. A simple method was applied, involving an evaluation of the likelihood of the Stated Policies scenario (STEPS) oil demand being realised, contra the likelihood of the Sustainable Development scenario (SDS). A weighted average of the two scenarios was then calculated based on these probabilities (see Table 12).

Weighting to STEPS	2030	2040
Power sector	10%	5%
Industry	40%	25%
Transport	35%	25%
Buildings	50%	25%
Petrochem. feedstock	75%	50%
International bunkers	50%	20%
Resulting weighted average[9]	**43%**	**28%**

Table 12: Weightings allocated to the STEPS (vs SDS) scenario in estimating future oil demand

This methodology is simplification of two very complex model calculations, but it is deemed to be a worthwhile exercise that can yield a simple quantitative

[9] Takes into consideration the size of the sub-sector, thus reflecting the total average

assessment of oil demand going forward based on the development path deemed most likely. The rationale for each sub-sector is provided below.

Power sector

Due to numerous generation alternatives that are cheaper, the power sector has been one of the sectors that has most readily reduced its oil consumption. It is assessed that this will continue, and that the oil demand for this sector will most likely be much closer to that of the SDS scenario.

Industry

Within industry there are several sub-sectors that can be electrified in a cost-effective manner, particularly within light industry. As indicated in the 2nd column of the figure below, this is precisely where the majority of oil savings in the SDS scenario are forecasted to take place. As the cost of electrification are reduced for industry, it is assessed that many companies will shift from oil to electricity to reduce costs, but there will also be a growing number of companies that will do so to meet shareholder and/or customer demands of reducing their carbon footprint.

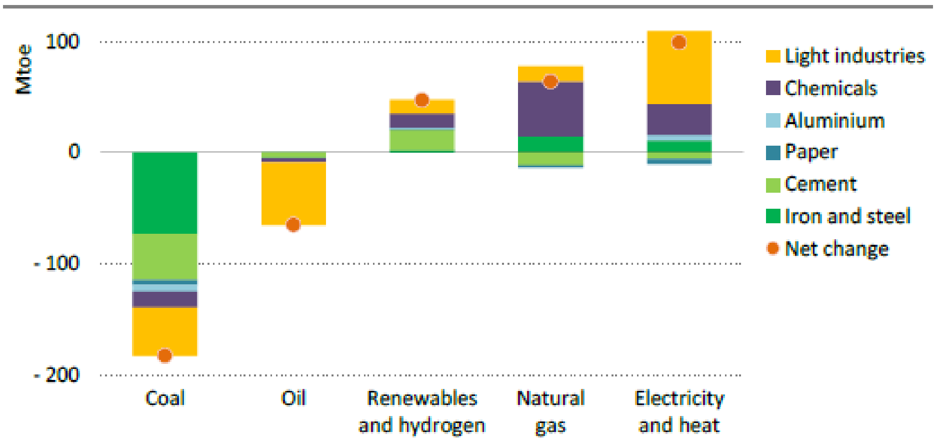

Figure 33: Changes in fuel consumption for energy and feedstock use in industry in the SDS scenario. (Cozzi et al., 2020)

For industry, it is thus assessed that there is a 40% chance of the STEPS related oil demand in 2030, with this falling to roughly 25% in 2040.

Transport

As was illustrated in Figure 32 previously, the transport sector is the largest utiliser of oil today, and it is also the sector with the largest difference in oil demand between the STEPS and SDS scenarios. Within the transport sector there are 4 main subsectors, each with differing potentials, and related costs, to shift from oil to alternative fuels. These 4 subsectors, along with rough estimates of their proportion of total transport oil demand as of 2019, are:

- Passenger and light commercial road transport - 49%
- Heavy road transport - 28%
- Domestic shipping - 6%
- Domestic aviation - 7%

The figure below displays how oil demand is anticipated to evolve for each of these subsectors in the STEPS.

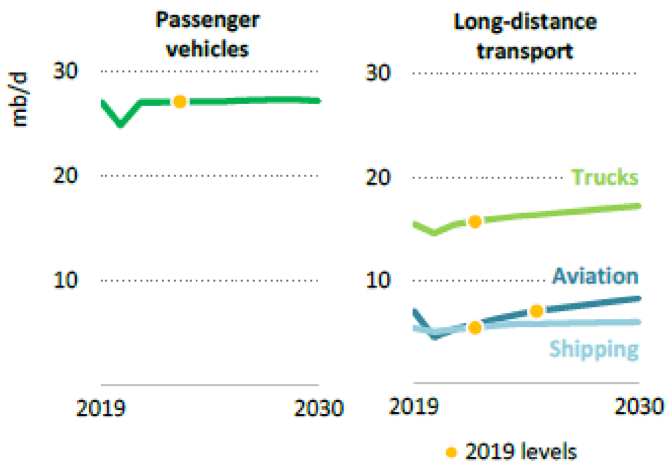

Figure 34: Oil demand by transport subsectors in the STEPS, 2019-2030. (Cozzi et al., 2020)

One of the most important parameters in determining the development in oil demand for road transport is share of new vehicle sales that is primarily electricity or hydrogen powered. The figure below displays these assumptions for three of the WEOs 2020 scenarios.

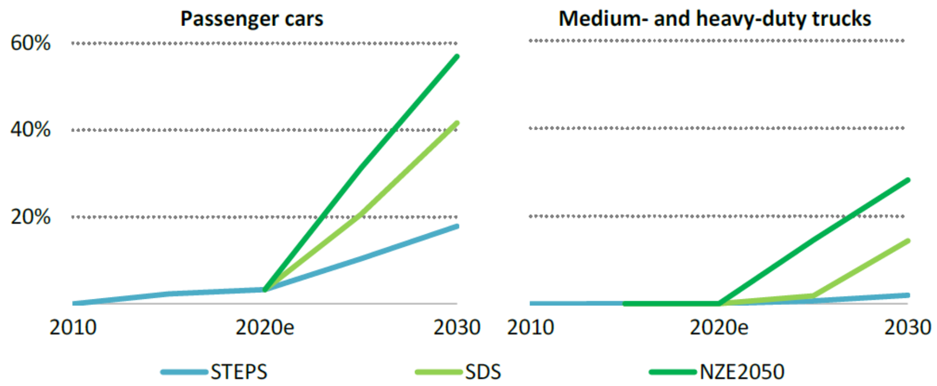

Figure 35: Share of new vehicle shares that are electric or fuel-cell powered in the STEPS, SDS, and Net Zero in 2050 scenarios.

Ea has undertaken a number of analyses that have involved modelling future vehicle fleets in Europe, as well as countries and regions in Asia, North America, and Africa. These analyses involved investigating the total cost of ownership (TCO) for various vehicle segments given the local circumstances. One of the driving forces behind electrification in these scenarios in recent years has been the fall in battery prices (see Figure 36), and according to a recent Bloomberg report, some electric busses in China recently reported prices below $100/kWh for the first time. This $100/kWh figure has been seen as a milestone, as it is understood that at this price EVs can be produced for the same price as their fossil-fuelled competitors. According to Bloomberg, it now appears clear that the volumed-weighted average battery pack price target of $100/kWh can be achieved by 2023, thus paving the way for cost parity (Henze, 2020).

Source: BloombergNEF

Figure 36: Development in volume-weighted average battery pack prices (comprised of pack and cell prices) (2020 USD/kWh) (Henze, 2020)

The trend of falling battery prices is anticipated to continue going forward, with Bloomberg for example estimating 2030 battery pack prices to average less than $60/kWh (Henze, 2020). However, the future price of EVs will also be driven down by the large upscaling in EV manufacturing capacity that is starting to take place now and will carry on during the next decades. Producing EVs in quantities similar to those from production runs for petrol and diesel vehicles today, combined with falling battery prices, should lead to upfront cost parity between EVs and their counterparts being reached well prior to 2030 for the majority of market segments. When lower upfront costs are combined with lower fuel and maintenance costs relative to petrol and diesel cars, this will most likely result in a rapid uptake of EVs. In addition, once cost parity is reached, local environmental issues such as air pollution will be a strong driver for electrification, particularly in regions with local air pollution issues and large populations within Asia.

This rapid uptake is reflected in scenarios such as those undertaken by Bloomberg, which assumes that by 2025, EVs will represent 10% of new passenger vehicles, with this rising to 28% in 2030, and 58% in 2040 (BloombergNEF, 2020). The figure below displays the EV share of global new vehicle sales by segment (left side) and the EV share of global vehicle fleets by segment (right side) from the Bloomberg scenarios.

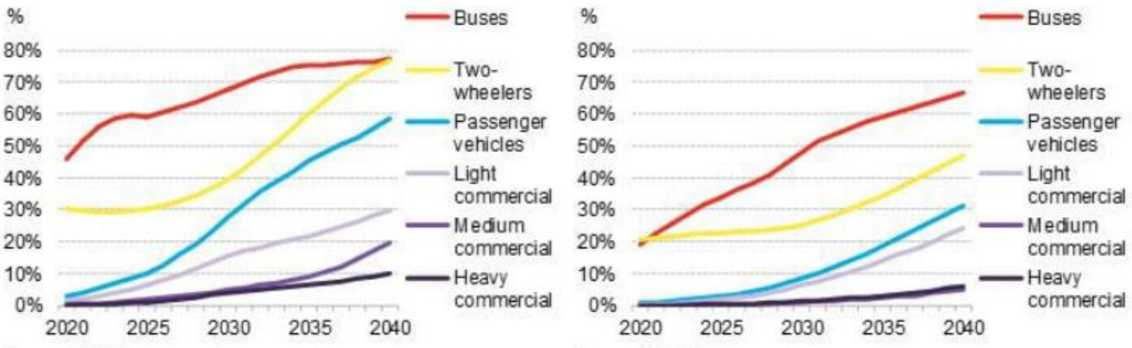

Figure 37: EV share of global new vehicle sales by segment (left side) and the EV share of global vehicle fleets by segment (right side) from the Bloomberg scenarios. (BloombergNEF, 2020)

The following table compares the forecasts from the Bloomberg EV Outlook 2020 scenarios with those from the 2020 WEO (i.e., from Figure 37 and Figure 35 respectively).

Road transport subsector	2030			
	STEPS	SDS	NZE 2050	BNEF*
Passenger cars	19%	41%	57%	28%
Light commercial	n/a	n/a	n/a	15%
Medium and Heavy	2%	16%	28%	9%
Busses (fleet %) **	(7%)	(12%)	n/a	65% (45%)

*Table 13: Share of 2030 new vehicle sales that are electric or hydrogen per road transport subsector in the three 2020 WEO scenarios and the Bloomberg EV Outlook 2020 scenario. *Note that Bloomberg figures are only for EVs, i.e., they do not include hydrogen vehicles. **Note, for the WEO scenarios, only fleet totals for busses were available and they are included in brackets.* (IEA, 2020a) (BloombergNEF, 2020)

In comparing the IEA scenarios with the Bloomberg scenarios, it should be noted that Bloomberg is amongst the more optimistic in terms of their expectations for battery development and EV rollout. However, when reviewing previous Bloomberg forecasts, despite the fact that they were also amongst the most optimistic at the time, actual battery development and price reductions turned out to exceed even Bloomberg's expectations. Based on this, a future EV rollout scenario roughly halfway between the STEPS and SDS scenarios would be most likely. However, after these scenarios were developed, the Biden administration recently ordered U.S. agencies to revisit fuel efficiency standards (Shepardson, 2021). In addition, his administration has indicated that it wishes to greatly increase the rollout of EVs.

Based on all the above, it is Ea's assessment that a transport scenario in line with the SDS would be more likely than that of the STEPS, and therefore weightings of 35% and 25% were given to the STEPS scenarios in 2030 and 2040 respectively.

Buildings
Experience shows that it is quite difficult to induce rapid changes in building heating systems without strong policy-incentives (Government bans or heavy taxation). It seems quite unlikely that such policies will be deployed aggressively on a global scale over the next 10 – 20 years. In other words, it can be difficult to motivate individuals to invest in replacement of existing oil furnaces in buildings prior to their end-life, even when it is slightly cost-effective to do so within a 10 – 20-year time horizon. A 50% weighting to the STEPS has thus been applied to 2030, with this falling to 25% in 2040.

Petrochemical feedstocks
Due to climate change policies and supported by the rapid decline in the costs of producing RE electricity based on wind and solar, the prospects of producing large-scale electrofuels (also called PtX-fuels) seem favourable. The EU commission has launched a 60 GW hydrogen strategy by 2030, and countries in the Americas and Asia have also launched PtX and hydrogen strategies and some of these fuels could potentially be used as petrochemical feedstocks.

International Bunkers
International bunkers comprise the fuels used by ships and aircraft when travelling on international routes. Mærsk, the world's largest shipping company recently announced that its first methanol fuelled container ship will be ready in 2023, seven years earlier than previously announced. This is part of the company's overall goal of having an entirely CO_2-neutral fleet by 2050 (Maritime Danmark, 2021). With market leaders taking steps such as these, it is likely that many other companies will follow suit.

For international aviation it will likely be more difficult to cost-effectively produce the required CO_2 neutral fuels to greatly reduce oil demand, particularly in 2030.

The results of applying an average weighting to each sector is displayed in Figure 38.

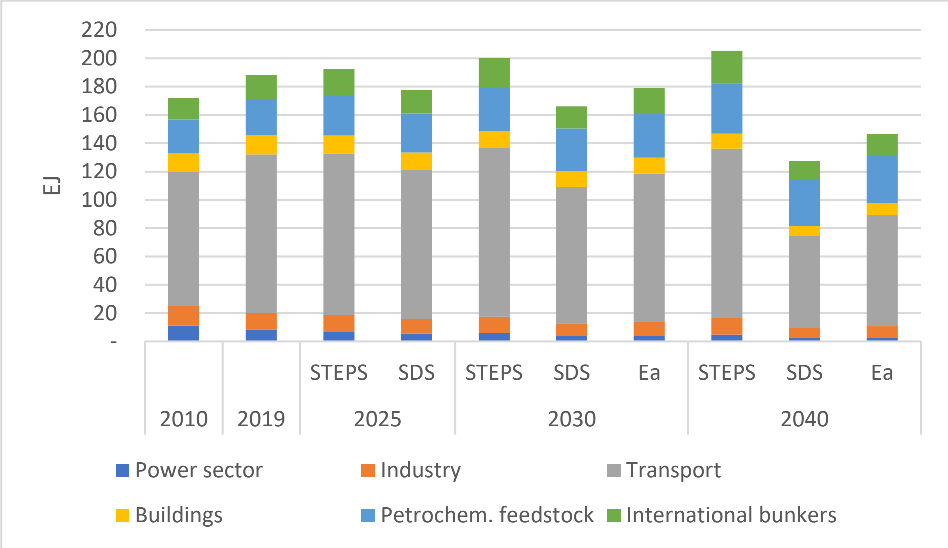

Figure 38: Oil demand according to WEO 2020 scenario and constructed weighted average Ea scenario.

In determining how varying oil demands in the future will affect prices, it is also relevant to look at what type of oil is anticipated to be produced in the various scenarios. Based on the weighted average demand from above, the 'Ea' demand scenario has been added to the STEPS and SDS scenarios, now displayed in oil production (million barrels per day).

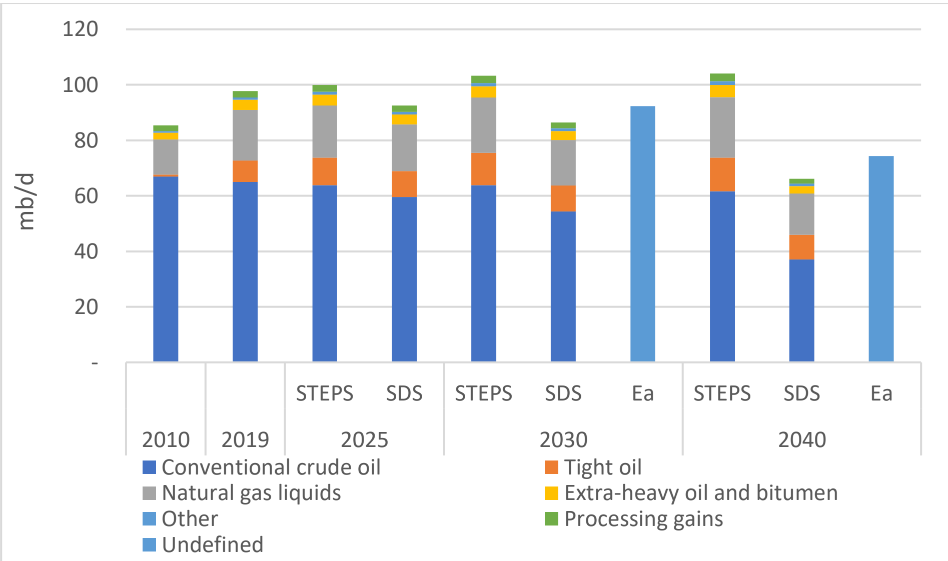

Figure 39: Historic and projected global oil production and supply for (mb/d) in the Stated Polices (STEPS), and Sustainable Development (SDS) scenarios from the 2020 IEA WEO, as well as the Ea weighted average scenario.

Ea conclusion on prices

The current chapter has analysed numerous aspects and inputs to arrive at a central price forecast for oil. To summarise, the final price forecasts are based on four elements:

- A review of various price forecasts from a variety of sources
- An evaluation of the IEA's track record to produce price forecasts, as well as the challenges it has faced in forecasting renewables
- A sector-by-sector evaluation of the most likely scenario, and the application of a weighted average based on this approach
- A growing international consensus and political willingness in achieving net-zero emission targets. Most recently this was highlighted by China pledging to be CO_2 neutral by 2060, and the Biden Administration indicating that the USA aims at achieving this target in 2050.

Given the situation the past year, a reflection on the effect of COVID-19 on future prices is also relevant. It could be argued that COVID-19 has increased uncertainty about the oil market for the next 5 -10 years or so, and has, at the very least, delayed the need for new exploration to fill the gap of declining fields. However, as any oil finds in Greenland are unlikely to start producing prior to 2030, COVID-19s direct effects on longer-term oil prices are not expected to be significant.

Finally, and related to the timing of any potential new Greenlandic oil production, any oil fields starting to produce after 2030 are likely to still be producing well after 2040, which is the end date for the WEO price forecasts. It was therefore necessary to extend the price forecasts through to 2065.

The final approach involved producing three price scenarios:

- STEPS convergence: a combination of forward prices in the short term and STEPS long-term prices until 2040.
- SDS convergence: a combination of forward prices in the short term and SDS long-term prices.
- Ea weighted average: The central scenario, it is a combination of the two above scenarios where the SDS' weighting increases from 50% in 2020 to 90% in 2065.

The table below summarises the assumptions utilised in the three oil price scenarios for various periods during the scenario timeframe.

	2021-2030	2030-2040	2040-2050	2040-2050
STEPS - convergence ($STEPS_{con}$)	2021: 90% weighting on forwards 2030: 100% weighting on STEPS long-term price trend	100% based on STEPS long-term price trend (price points in 2030, 2035, 2040)	Applied a growth rate equal to 50% of that from 2030 to 2040.	Maintained 2050 price
SDS - convergence (SDS_{con})	2021: 90% weighting on forwards 2030: 100% weighting on SDS long-term price trend	100% based on STEPS long-term price trend (price points in 2025 & 2040)	Continued trend from 2030 to 2040.	Maintained 2050 price
Ea - weighted average	**50% weighting on $STEPS_{con}$ in 2020, falling to 35% in 2030**	**35% weighting on $STEPS_{con}$ in 2030, falling to 25% in 2040**	**25% weighting on $STEPS_{con}$ in 2040, falling to 20% in 2035**	**20% weighting on $STEPS_{con}$ in 2050, falling to 10% in 2065**

Table 14: Assumptions utilised in the three oil price scenarios

The resulting price scenarios are displayed in Figure 40.

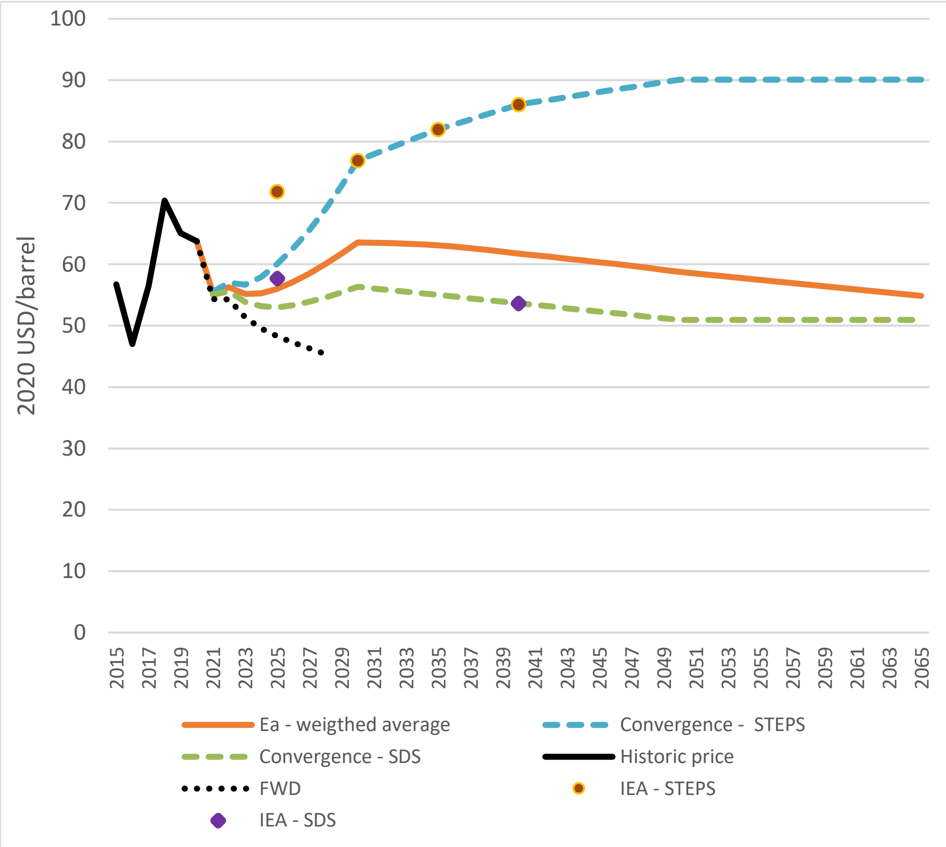

Figure 40: Three future oil price scenarios. STEPS convergence: a combination of forward prices in the short term and STEPS long-term prices until 2040. SDS convergence: a combination of forward prices in the short term and SDS long-term prices. Ea weighted average: a combination of the two above scenarios where the SDS' weighing increases from 50% in 2020 to 90% in 2065.

8 Economics of oil exploration and extraction in Greenland

8.1 Government take structure in Greenland

Attracting investments in oil exploration in Greenland is challenged by several factors, the most relevant likely being that Greenland is a frontier region and has a harsh natural climate. Therefore, with a view to make Greenland more attractive to oil companies and stay competitive among other frontier regions, Naalakkersuisut decided to impose a new tax regime, or government take model, in the new oil strategy for Greenland 2020-24.

Typically, government take models for the oil industry and other extraction industries are comprised of different components, such as royalty on turnover, royalty on profit, corporate taxes and in some cases compulsory government participation or ownership. For oil companies it is not only the expected government take percentage that is of importance, but also the way it is structured. In frontier regions, with larger uncertainty and lack of onshore infrastructure, oil companies will likely want to avoid turnover royalties and instead pay corporate taxes. From a government perspective, royalties on parameters which are more transparent, such as turnover or volume are preferred. Likewise, a model which yields to the society regardless of the oil prices is preferred.

Before Greenland changed its government take structure, the overall take was slightly below the government take structure in other oil producing regions in the Arctics (Canada and Alaska), but above frontier regions in Northern Europe, and above mature markets in US Gulf of Mexico and Russia[10]. The new and lower government take rates are also referred to as the first mover scheme. In other words, the more favourable terms will be offered to oil companies applying for an exploration and exploitation license in the strategy period 2020 to 2024.

Comparing the current and former government take structure in Greenland

The table below displays the current and former take structure, with the effective rate being based on an oil price of 80 USD/barrel. However, it should be noted that changes in oil prices will also change the effective rate calculated below and consequently the government take percentage. Hence, a lower oil

[10] Naalakkersuisut, 2020, Oliestrategi 2020-2024, p. 60, Nuuk.

price will reduce the total government take as a percentage of the turnover, while a higher oil price will increase the government take as it will trigger a higher surplus royalty.

	Former model (before 2020)		Current model for 2020-24	
	Nominal rate	Effective rate*	Nominal rate	Effective rate*
Royalty on turnover	2.5%	5.5%	0 %	0%
Surplus royalty	7.5/17.5/30%	12.9%	3.75/8.75/15%	7.2%
Corporate withholding tax	25/36%	29.4%	25/36%	33.4%
Government participation	6.25%	3.6%	0%	0%
Total government take		**51.3%**		**40.6%**

*Table 15: Comparison of current and former government take structure in Greenland. *Note, the effective rate is calculated based upon a scenario with a barrel price of 80 USD. Source: Naalakkersuisut, 2020, Getting Greenland back on track with oil, Nuuk.*

The current government take model provides investors with a larger degree of security compared to the previous model, as investors will only pay taxes and royalties in years where the company generates a profit, and the surplus royalty is modest until the profit exceeds a certain threshold. This also means that if oil prices are low the government take can be below 30%, and in years with very low oil prices, Greenland will receive no or very modest revenues from oil exploration. The actual government take will depend upon the cost structure for the specific license and the global oil price.

The current government take model is also more vulnerable to transfer pricing[11], as corporate withholding tax is now making up the bulk of the government take.

8.2 Historic estimates of exploration costs since the 2000s

Based on budget reports from OCMs (Organizing Committee Meetings), along with the license text for each signed license, estimates of exploration costs since the early 2000s have been undertaken. These estimates include spending on geological and geophysical data acquisition, environmental projects, non-

[11] Transfer pricing is when a company sells commodities at a lower price, compared to the world market, to an affiliated company in another country with a view to achieving tax advantages.

specific projects, application fees and educational fees, but exclude money spent on prospecting licenses, academia and authorities.

Total exploration costs

Since the beginning of the 2000s, the total sum spent on exploration and for fulfilling work programs and license terms was roughly 12.4 billion DKK, of which 0.38 billion DKK went to Non-geological funds (non-specific projects, local capacity projects, application fees and educational fees, environmental studies, and funds at the Greenland authority's disposal. Exploration costs during various periods since 2002 are displayed in Figure 41.

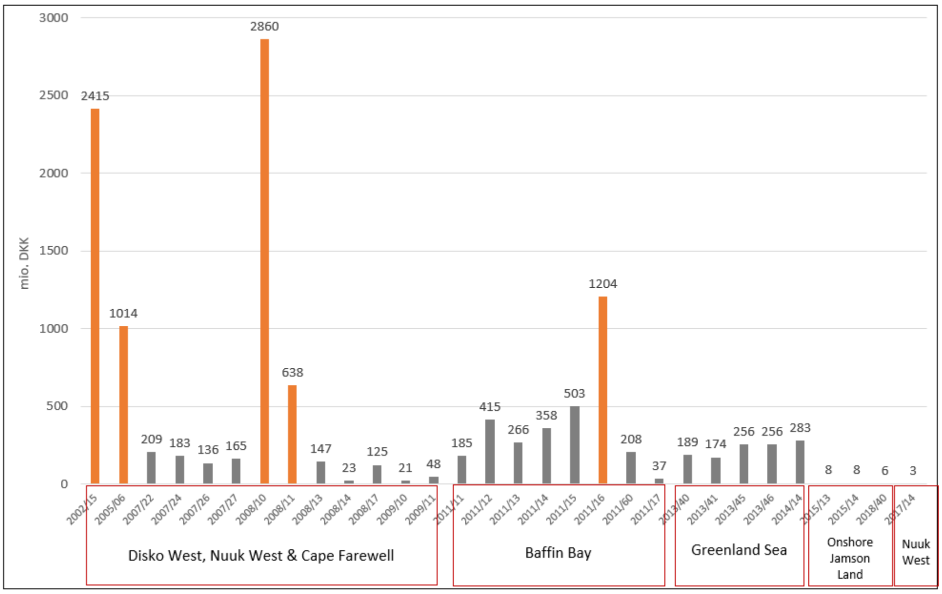

Figure 41: Total spending (in millions of DKK) for each license. Orange columns indicate licenses with exploration drilling. Spending includes both geological and geophysical work programmes, local capacity projects, non-specific project funds, environmental projects and license and educational fees.

Cairn Energy spent more than 1 billion USD (roughly 7 billion DKK) on their drilling campaign in 2010 and 2011. This is clearly reflected in the orange columns in the above figure, thus highlighting the fact that in areas where drilling has taken place, exploration costs increase immensely.

The total costs according to license area are displayed in Table 16.

License Area	Total Cost	Non-geological funds	Average total cost per license
Disko West, Nuuk West & Cape Farewell	7,983	120.2	614.0
Baffin Bay	3,177	56.1	453.8
Greenland Sea	1,158	203.1	
Jameson Land	22	3.8	
Total	**12,339**	**383**	

Table 16: Total exploration costs for each assessment unit, unspecified project funds and the average total cost per license in each assessment unit (millions of DKK).

Non-geological funds

While non-geological funds have only accounted for roughly 3% of total exploration costs, thus highlighting the fact that during the exploration phase, data acquisition constitutes the vast majority of spending, non-geological funds are important as the majority of these funds are paid to, or are at the disposal of, Greenland's authorities.[12] The only exception here is funds spent on environmental studies. The figure below displays the development in non-geological funding, as well as the % of these funds that are used on environmental studies.

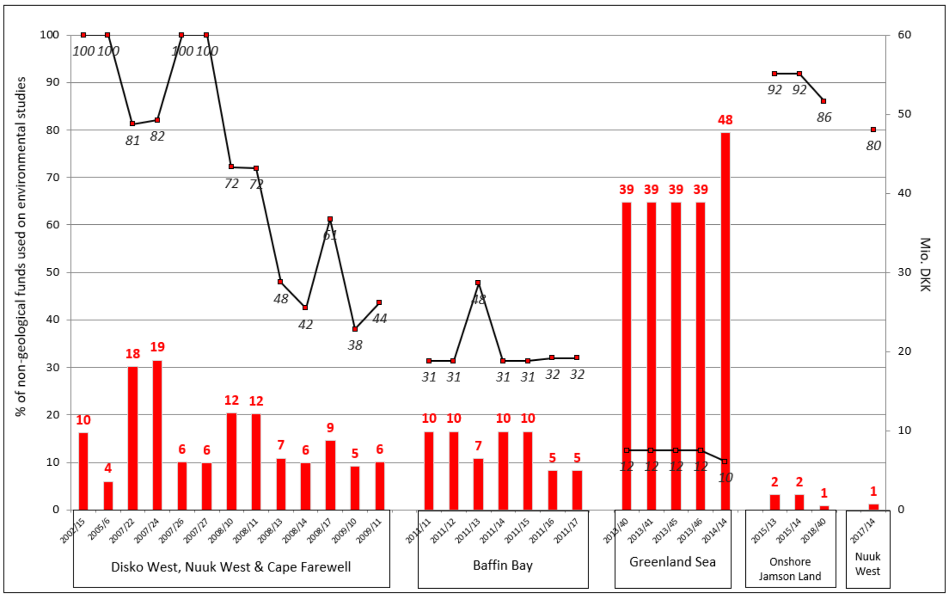

Figure 42: Development in non-geological funding in millions of DKK (red columns and right axis), as well as the % of these funds that are used on environmental studies (left axis).

[12] It should be noted that tax revenues are not included in these figures, which reportedly were in the range of 300 mio. DKK during this time period.

The figure highlights a clear trend, where the portion of non-geological funds going to environmental studies fell over time, with the only exception being the more recent licences in Jameson Land.

8.3 Potential investment challenges for oil and gas in Greenland

Throughout the years, Greenland has been able to attract the interest of investors to explore and develop its untapped oil and gas resources. Since the 1970s, several major, independent (ICs), and national oil and gas companies (NCs) have ventured into exploration efforts, which have nonetheless proven commercially unsuccessful (for a summary, see Figure 43). The combination of a favourable regulatory framework with the existing evidence that Greenland possesses substantial resources may explain the industry's interest in the country's potential as an oil and gas nation.

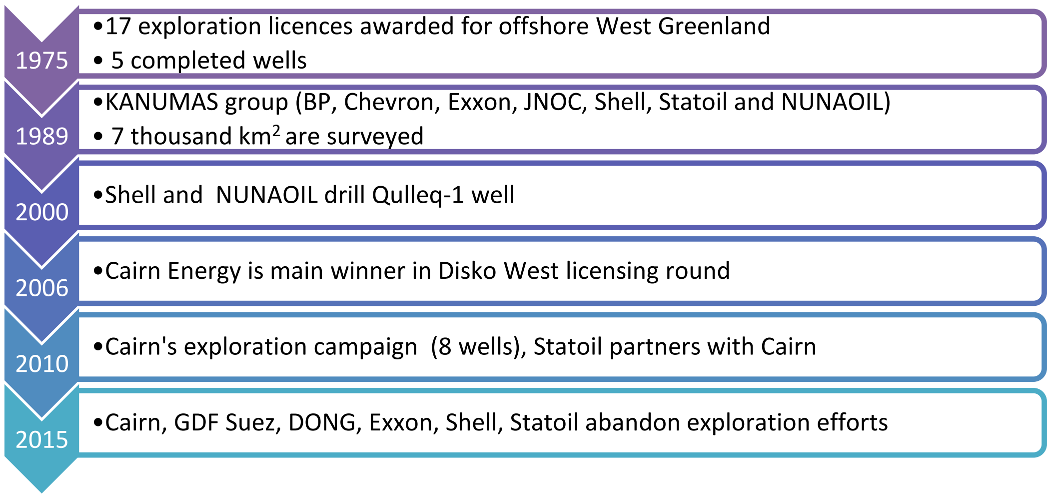

Figure 43: Summarized timeline of exploration efforts in Greenland. Source. Sources: Henderson & Loe (2016) *and NUNAOIL*

Recent results by the Geological Survey of Denmark and Greenland (GEUS), the Ministry of Mineral Resources and NUNAOIL confirm the importance of Greenland's oil and gas reserves, which for the western part of the country are estimated at approximately 18 billion barrels of oil equivalent (BOE).[13] While the methodology and geographical scope of the study is not exactly comparable with the widely cited USGS study of 2008 by Charpentier et al. (2008), the orders of magnitude are very similar (a comparison can be found in Table 8, section 5.2 of the present report).

[13] Estimates for Eastern Greenland will become available during the Spring of 2021 and are expected to be twice the size of those in the west. For further details, refer to section 5.2 of the present report.

The USGS study of 2008 claimed that two out of the five basins containing 70% of the mean undiscovered oil resources in the Circum-Arctic are Greenlandic. Furthermore, the study found that 84% of the undiscovered oil and gas in the region occurs offshore. The study also confirmed that, overall, Greenland is home to approximately 52 billion of barrels of undiscovered oil and oil-equivalent natural gas. The three relevant oil and gas provinces, whereof Greenlandic resources can be claimed to exist, are respectively ranked as fourth, seventh and fourteenth in the USGS assessment of the Circum-Arctic region, meaning that the two most promising Greenlandic oil and gas provinces are in the top 10 of the Circum-Arctic region (see Table 17).

Province	Oil (Billions BO)	Oil and Gas (Billions BOE)	Overall ranking in Circum-Arctic appraisal
Arctic Alaska	29.96	72.77	2
Amerasia Basin	9.72	19.75	6
East Greenland Reef Basins	8.90	31.39	4
West Greenland - East Canada	7.27	17.06	7
North Greenland Sheared Margin	1.35	3.32	14

Table 17: Extract of the USGS Circum-Arctic appraisal of 2008. Source: Charpentier et al. (2008). Notes: "BO" stands for barrels of oil, while "BOE" stands for barrels of oil and oil-equivalent natural gas.

However, the industry's interest in Greenland throughout the past four decades can be best described as irregular, rather than as a continued, long-term effort to explore the country's resources and produce them commercially.

Oil and Gas industry's interest in Greenland has been inconstant

Several "bursts" of interest in the country by relevant industry players have been followed by the subsequent abandonment or postponement of efforts. In 2015 - in the middle of a plunge in oil prices - DONG Energy (now Ørsted), GDF Suez and Statoil (now Equinor) handed their licences back (Reuters, 2015). Simultaneously, Shell, Mærsk and Cairn Energy announced the temporary postponement of its interest in the further exploration of oil and gas in Greenland (Kalaallit Nunaata Radioa, 2015). But even before the low-price environment of 2015, ExxonMobil turned in its back on Greenland's prospects (Børsen, 2013).[14]

[14] Cairn Energy's exit came after having reportedly spent more than one-half billion USD by 2012 (BBC News, 2011), to later (in 2015) officially declare that it was relinquishing all licences in Greenland, except for the one containing the Pitu Prospect (in Baffin Bay). Associated exploration costs were either impaired or written off, according to the firm's financial reports (Cairn Energy, 2015).

Arctic oil and gas development is the result of a decade-long effort

While the market environment of the time (2015) was indeed challenging for all producers (see Figure 44), time proved that Greenland was hit harder than comparable but more resilient provinces in other Arctic territories, such as Russia, Norway, and Alaska. In these, oil and gas development has been sustained throughout decades, in line with a long-term strategy focused on developing technical expertise and on mitigating economic risks.

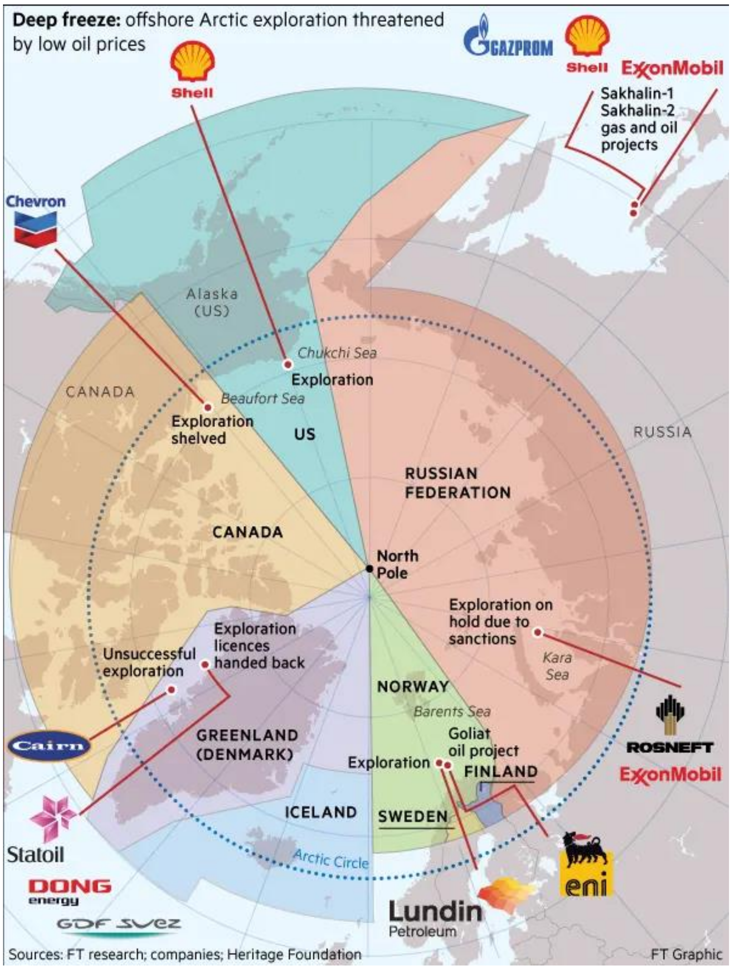

Figure 44: Infographic on the 2015 status of Arctic exploration. Source: (Financial Times, 2015)

It may take between 10 to 15 years between discovery and commercial production

One good example is BP's six-decade journey in the development of Alaska's Prudhoe Bay (S&P Global, 2020a), but also Russia's sustained effort, which provides a contemporary example of the realistic timescale between first exploration and initial production. In this respect, Henderson & Loe (2016) argue that under the harsh climatic conditions of the Arctic, it is expected that between a decade and fifteen years is the expected amount of time between first exploration and initial production.

For example, Rosneft - one of Russia's NCs - entered already in 1995 a production agreement with ExxonMobil, India's ONGC Videsh and Japan's SODECO for the development of the sub-Arctic Sakhalin 1 project, which in 2018 produced an average of 300 thousand barrels per day (bpd) (Reuters, 2020a).[15] The field was discovered in 1977 but delivered its first commercial production in 2005 (Henderson & Loe, 2016).

Similarly, Norway's NC Equinor (former Statoil) announced in 2019 a new discovery of light oil in the Barents Sea, an area that the Norwegian government has focused on developing, despite increasing opposition in recent times (Equinor, 2019; Reuters, 2020b). In the absence of sufficiently developed infrastructure, Equinor (2020) also announced that the Johan Castberg field is expected to come on stream with the help of a Floating Production Storage and Offloading (FSPSO) solution in 2023, which will help the company to save on approximately 50% of its initially projected costs. It is relevant to note that Equinor's announcement on commercial production at the Johan Castberg field comes with at least 5 years of delays and one decade since the initial discovery (Henderson & Loe, 2016).

Even in more mature territories, like Alaska, where limitations to further oil development have been present throughout the years, interest in exploration and production has not entirely diminished, even after the difficult year faced by the industry in the middle of the COVID pandemic. In fact, ConocoPhilips is resuming production drilling in 2021, after popular vote rejected an increase to oil taxation in the American state (S&P Global, 2020b).

Factors affecting investors' sentiment on Greenland's oil resources

If the resource potential exists and regulatory conditions have been mostly favourable, then other elements must have played a role in the sentiment of potential investors in Greenland's oil and gas sector. A combination of factors may explain why the development of Greenland's oil and gas has been perceived as a less attractive opportunity than alternatives, including those available in comparable Arctic territories.

Limited infrastructure

The absence of infrastructure (Reuters, 2015), as Greenland is more remote and less populated than its counterparts may be a key deterrent. This has direct implications for the costs and complexity of exploration campaigns, as

[15] The Sakhalin 1 project partners have the following shares: Rosneft, 20%, Exxon, 30%; SODECO, 30% and ONGC Videsh, 20%. As a follow-up to Sakhalin 1, the Sakhalin 2 project (which began production in 2009) is followed by the Sakhalin 2 project, where Shell (27,5%), Gazprom (50%), Mitsui (12,5%) and Mitsubishi (10%) are partners. The Sakhalin projects actually happen south of the Arctic circle but are considered comparably challenging.

equipment (rigs, platforms and so on) needs to be assembled and transported from longer distances and within narrower timeframes. The exploration of the Arctic creates substantial logistic limitations, as the winter period is harsher and longer than in other places.

Transportation during the winter months may be challenging

Depending on the exact location of the reservoir to be developed, transportation to the midstream and downstream levels of the supply chain may also create additional costs. In projects developed in regions with harsh winters, Arctic navigation is limited to some months of the year and must be done with ice-breaking vessels.

Uncertain exploration, development and production costs

Higher and considerably more uncertain exploration, development and production costs than alternative investments may also play a fundamental role. Previous knowledge of the basins eases the exploration and production effort. So far, oil and gas reservoirs in Greenland remain undiscovered, whereas in other Arctic territories, there is production already going on.

To illustrate differing conditions in potential oil and gas investments, Table 18 compares Cairn Energy's exploration campaign with Rosneft's exploration activities in the Russian Arctic and Total's acquisition of Mærsk Oil assets.[16]

According to press reports by Reuters (2015), Cairn Energy's 2010 – 2011 unsuccessful exploration campaign involved drilling eight wells at an estimated cost of 1.2 billion USD. Earlier press reports by the Financial Times (2011) explained the company's rationale behind the campaign in the following terms. A 500-million-barrel discovery would generate profits at a price of 40 USD/barrel, while a 250-million-barrel discovery would be profitable at 60 USD/barrel. However, these breakeven prices could well be too optimistic, as they may have ignored or underestimated the substantial development costs required to make of Greenland a producing province, after the exploration stage.

On the other hand, upstream exploration and development costs may be lower at present than they were approximately 10 years ago, as a consequence of technological development and a changing economic environment characterized by lower crude oil prices.

[16] Although Mærsk Oil's assets were not located in the Arctic, they are shown here to compare Cairn Energy's exploration campaign with oil investments in proven, already producing assets.

By comparison, Henderson & Loe (2016) estimated that Rosneft's entire exploration campaign in the Arctic during the period 2014 – 2020 could cost up to 8.2 billion USD, an amount that would be split among several partners.[17] Furthermore, the potential development cost could reach up to 562 billion USD, an investment expense that would be executed throughout approximately two decades. Regarding breakeven prices, S&P Global (2020d) estimates that the Russian average to be around 20 USD/barrel for onshore projects close to existing infrastructure, but this can be up to 100 USD/barrel if "government assistance" (e.g. tax incentives) is absent. Henderson & Grushevenko (2019) further indicate that the economics of any Arctic project in Russia become challenging if the price is under 80 USD/barrel.

A closer point of comparison to Cairn's exploration campaign in Greenland is Total's acquisition of Mærsk Oil's already producing assets for 7.45 billion USD (Total, 2017). The transaction made of Total the second-largest operator in the North Sea, with an approximate production of 500 thousand BOE by 2020, of which the Danish part of the North Sea presently produces an average 103 thousand BOE (Energiwatch, 2021). According to industry's unofficial reports, the breakeven price in the Danish North Sea is 15 USD/barrel on average.

Investment opportunity	Cost (billion USD)	Breakeven price (USD/barrel)
Cairn Energy's exploration campaign in Greenland (2010-2011)	1.2	40 - 60
Rosneft's Arctic exploration (with partners Exxon, ENI, Equinor) 2014-2020	7.7 – 8.2	20 – 100
Total's acquisition of Mærsk Oil's assets	7.45	12 – 18 (Danish North Sea)

Table 18: Comparison of selected oil and gas investment opportunities. Sources: Financial Times (2011), Reuters (2015), Henderson & Loe (2016), S&P Global (2020d).

Limited access to skilled and semi-skilled labour

Another element that may play against Greenland's development of its oil and gas resources is the absence or limited access to skilled and semi-skilled labour. This could increase the salary costs and place Greenland behind alternative places, where labour with the necessary skills to advance oil and gas exploration and development is readily available.

[17] Rosneft owns 45 exploration licences in the Russian Arctic, which contains an estimated 240 billion barrels of oil and oil-equivalent natural gas. See Charpentier et al., (2008) and Henderson & Loe (2016) for further details.

Heavy reputational cost associated with potential environmental damage

Another strong deterrent for potential entrants into Greenland's oil and gas sector is the very high reputational cost associated with a possible environmental damage affecting the country's ecosystem. In fact, during Cairn Energy's exploration campaign, there concerns of a chemical spill in Greenlandic waters.

The most recent event of this kind is rather recent: The oil spill of the Exxon Valdez tanker in Alaska (1989) and the explosion of the Deepwater Horizon offshore drilling rig (2010) in the Gulf of Mexico constitute two examples of how high the stakes can be.[18] Besides the far-reaching environmental effects (Beyer et al., 2016), the Deepwater Horizon disaster meant a loss in BP's market value of nearly 100 billion USD, and a plunge in the price of its stock to a 14-year low (Reuters, 2010). Total estimated costs borne by BP for the oil spill were estimated at 65 USD billion as of 2018 (Reuters, 2018).

It was in reference to this kind of concerns that Total's CEO (Christophe de Margerie) reportedly argued that oil on Greenland would be disastrous, as a potential leak would cause a huge damage on the image of the company (Reuters, 2012).

State of play of Arctic oil and gas: resilience despite COVID

Arctic oil and gas production is at present developed at commercial scale in Russia, Alaska, and Norway. National Companies, Independent Companies and major producers present a diverse picture of interests and technical capabilities participating in the ongoing exploration and production of Arctic oil and gas resources. Table 19 summarises the companies with a leading presence in Arctic and sub-Arctic environments.

It is evident that Russian companies take the lead, which can be explained by both the vast geographical extension of the country and the government's strategic interest in facilitating the industry's development in this part of its geography.

[18] These are the two largest oil spills in US history, with a release of respectively 41,000 m^3 in the Exxon Valdez case and 780,000 m^3 in the Deepwater Horizon case. For further details, see (Exxon Valdez Oil Spill Trustee Council, n.d.; United States Coast Guard, 2011)

Company	Country	Type	Arctic reserves in exploration and production (Billions BOE)	Arctic/sub-Arctic fields, projects, areas, Joint Ventures (JVs) (examples)
Gazprom	Russia	NC (majority)	58.75	Prirazlomnoye, Novoportovskoye
Novatek	Russia	IC	12.28	Yamal LNG, Arctic LNG 2
Rosneft	Russia	NC (majority)	6.57	Fedynsky, Novoogennoye
Lukoil	Russia	IC	3.51	Nenets Autonomous Area
ConocoPhillips	US	IC	3.07	Alaska's North Slope
Wintershall DEA	Germany	IC	2.15	Snøhvit, Dvalin
Total	France	Major	1.93	Yamal LNG, Snøhvit
CNPC	China	NC	1.66	Yamal LNG, Arctic LNG 2
OMV	Austria/UAE	IC	1.20	Wisting, Aasta Hansteen
Equinor	Norway	NC (majority)	1.09	Goliat, Snøhvit, Johan Castberg
ExxonMobil	US	Major	1.69	Sakhalin 1
BP	UK	Major	1.30	Owns 19,75% of Rosneft
CNOOC	China	NC	0.53	Arctic LNG 2
PETORO	Norway	Fund	0.52	Snøhvit
ONGC	India	NC	0.84	JV with Rosneft and Gazprom Neft
Silk Road Fund	China	Fund	0.56	Yamal LNG
Vår Energi	Norway/Italy	IC	0.29	Goliat
Zarubezhneft	Russia	NC	0.43	Peschanoozerskoye
PetroVietnam	Vietnam	NC	0.33	Dolginskoye (JV with Gazprom)
Repsol	Spain	IC	N/A	Joint Venture with Oil Search, Gazprom
Oil Search	New Guinea	IC	0.84	Alaska's North Slope
Alltech Group	Russia	IC	N/A	Pechora LNG project with Rsoneft
Hillcorp	USA	IC	0.21	Took over BP's stake in Prudhoe Bay
Indian Oil	India	NC	0.26	Sakhalin-1, Vankor
Oil India	India	NC	0.26	Taymyr Peninsula (Vankor) with Rosneft
Bharat Petroleum	India	NC	0.25	Joint Venture with Rosneft
Arcticshelfneftgaz	Russia	NC	N/A	Medynsk-Varandey (Barents)
Yargeo	Russia	NC	0.23	Novatek's subsidiary
ENI	Italy	Major	0.21	Owns 69,6% of Vår Energi, Samburskoye
Bashneft	Russia	NC	0.20	Rosneft's subsidiary

Table 19: Arctic's top 30 oil companies as of 2019. Sources: Oilchange et al. (2020) citing Rystad Energy's data and EA Energy Analysis' own research based on company's reports, press releases and media sources.

The majority state-owned NC Gazprom, whose production accounts for 12% of global gas output, tops the list of companies with arctic hydrocarbon reserves under production. Its oil-focused subsidiary Gazprom Neft reported that, as of 2019, approximately 30% of all its production took place within the Arctic circle (Gazprom Neft, 2020b). The map in Figure 45 contains Gazprom's upstream exploration and production activities in Russia and as can be seen, there is considerable exploration and activity with respect to both oil and gas throughout the country, but particularly in the Yamal peninsula (Siberia).

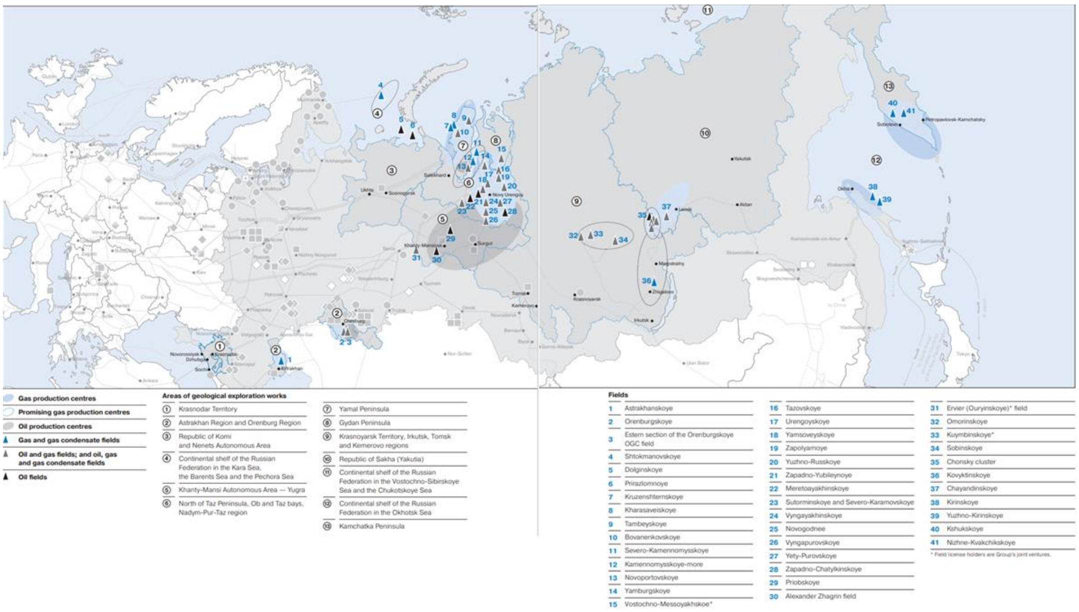

Figure 45: Hydrocarbon fields of Gazprom Group and joint ventures on the territory of the Russian Federation (exploration and production). Source: (Gazprom, 2020)

However, it can be argued that it is Rosneft the NC with broadest Arctic exploration throughout the country, with licences in both the East Arctic, the West Arctic, but not least Russia's far east, which is characterized by sub-Arctic conditions and where some of the earliest projects (such as Sakhalin 1) have been developed. The map in Figure 46 summarises the 45 licenses in Rosneft's possession, as of 2019.

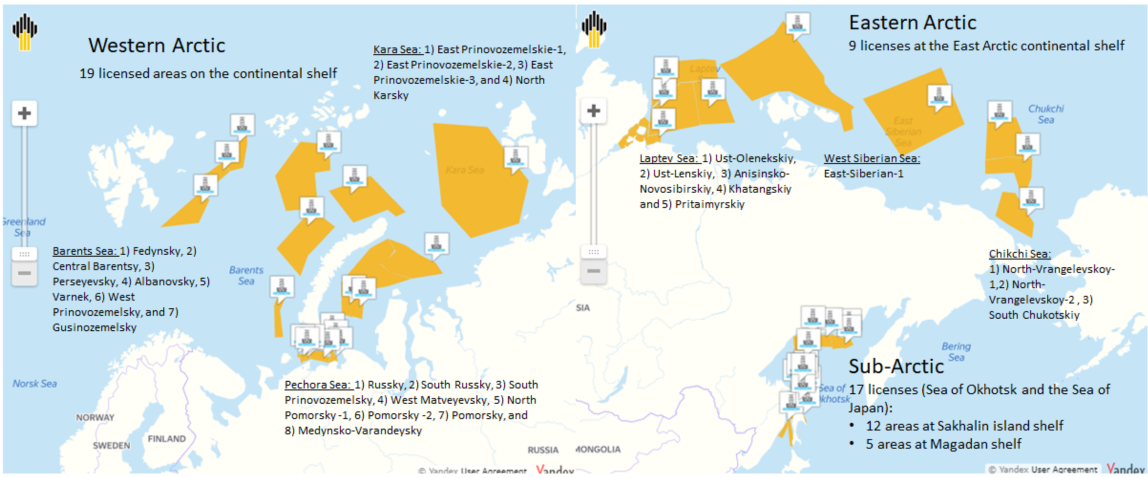

Figure 46: Rosneft's 45 licences in Arctic and Sub-Arctic regions. Source: adapted from Rosneft [Offshore projects (rosneft.com)]

Russia's Arctic development has also been led by independent players, such as Novatek, which is the country's largest IC with particular focus on natural gas. Among the company's flagship projects is Yamal LNG, where it holds the largest stake (50.1%) in a joint venture with Total (20%), China National Petroleum Corporation (CNPC-20%) and the Silk Road Fund (9.9%). The project, initiated in 2013, started production in 2017 and reached the thirty-million LNG production milestone in February of 2020.

The Yamal LNG project highlights the many complexities of Arctic hydrocarbon development, including physical transportation challenges. At the beginning of the project, there were no access routes to the site by land or by sea, which motivated the construction of the Sabetta port as well as an international airport. The development of ice-breaker tankers, capable of travelling in the middle of the winter, has also been part of the project. In addition, a new vessel route allows vessels to travel to demand centers in Asia through the Bering Strait rather than through the Suez Canal, reducing travel time from 30 days to 15 days (see Figure 47). However, travel can be made only between May and November (Total, 2015a).

In addition to the Yamal LNG, several high profile, follow-up projects are underway. One example is Arctic LNG2, which (at the end of 2020) is reported to be 32% complete. Together with partners Total, CNPC, CNOOC, Mitsui and Jogmec, Novatek takes the lead with a 60% share.

Figure 47: North Sea Route and South Sea Route. Source: (Total, 2015b)

Another country in full-fledged Arctic development is Norway, where the Barents Sea and the Norwegian Sea are home to a very active exploration activity, with the latest exploration licenses being allocated in January 2021 (Norwegian Ministry of Petroleum and Energy, 2021). The Barents Sea has two producing fields: Snøhvit and Goliat, which started production in respectively 2007 and 2016. The more recent discovery (2011), the Johan Castberg field, is expected to come on stream in late 2022. The majority state-owned Equinor plays an important role in such developments, together with a variety of international partners. The map in Figure 48 shows Equinor's activities in Norway.

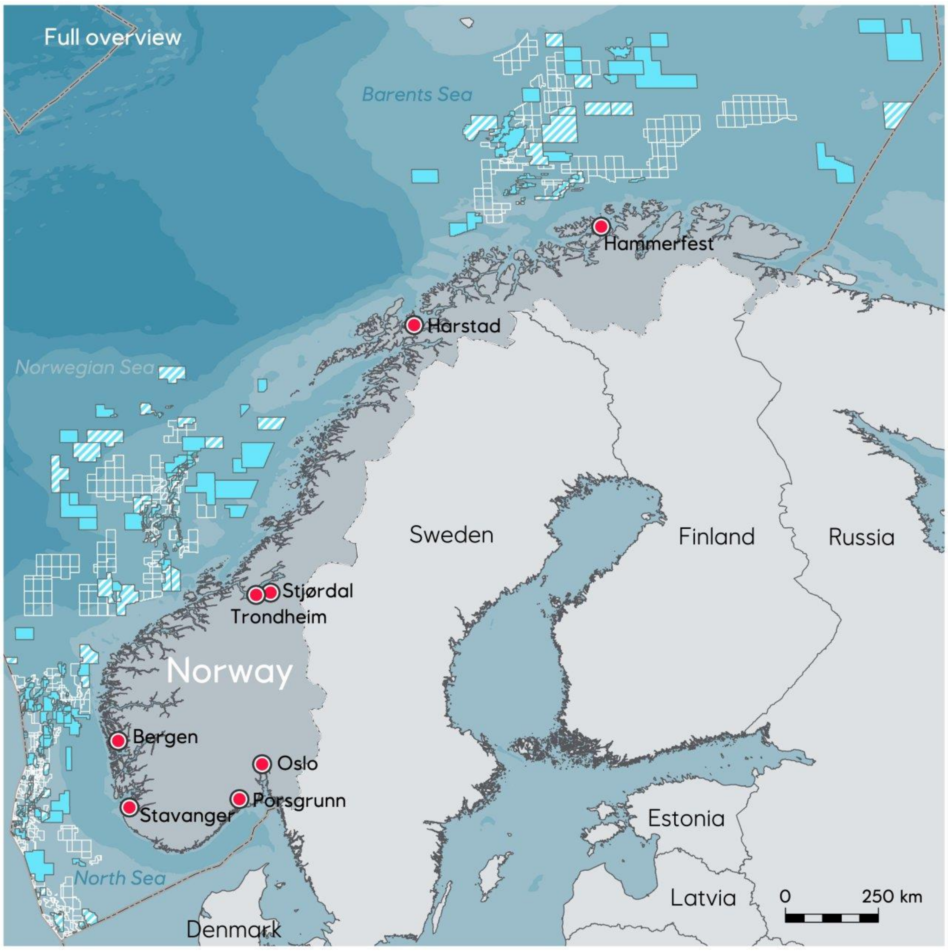

Figure 48: Equinor's presence in Norway. Source: Equinor's website ([Norway - Equinor activities in Norway - equinor.com](#))

A common feature of the territories with substantial Arctic oil and gas development is that governments have been strongly supportive by providing a stable and favourable regulatory framework for developers, regardless of the volatility in global oil and gas markets.

Equally important for development is the fact that there is an increasing variety of companies participating in the exploration and production of the Arctic's oil and gas resources.

National Companies in the host countries typically have the necessary ability to navigate the local environment, including the understanding of the relevant political and regulatory elements. Independent companies usually bring the ability to keep projects on track and on budget, in line with realistic yet high ambitions, but also a pressing need to add value.

Foreign national companies play an important role too, as they usually bring necessary financial resources to the table as well as the perspective of the countries sustaining demand for hydrocarbons. In the past few years, it has become increasingly common to observe the NCs of rapidly developing countries, such as India and China, enter agreements with larger and more traditional players. It is no coincidence that high-ranking spokespeople of the involved governments see these opportunities from a geopolitical perspective, as was recently declared by Russia that India could be the first Non-Arctic state extracting resources in the Arctic (Ministry of Foreign Affairs of the Russian Federation, 2020).

Major oil companies have also kept a sustained presence in the Arctic, despite their pledges to an increasing diversification of their portfolio and a stronger focus on renewables – a trend that has been accentuated after the severe drawbacks in the aftermath of the COVID crisis. ExxonMobil, Chevron and ConocoPhilips (all of them with a history in the Arctic) have recently seen their credit ratings downgraded after losing billions as a result of vanishing demand in 2020 (Reuters, 2021).

These events have put pressure on companies to rebrand themselves, but also to swiftly redirect their portfolios to renewables, to signal the importance of climate change. Among the examples is French major Total, which has recently proposed to change its name "TotalEnergies" to better reflect its ambition to reach carbon neutrality.

Other major producers with long traditions in the Arctic reaccommodate their positions while they attend to mounting pressure from shareholders and rating agencies. After six decades of presence in Alaska, BP sells its stake to US-based independent Hillcorp, weathers severe losses in 2020 and moves ahead with its strategic partnership with Rosneft, of which it owns approximately 20% (Financial Times, 2021; S&P Global, 2020a).

Shell is yet another example, which after earlier unsuccessful efforts for exploration of the Canadian Arctic, devices a new strategy (Shell, 2021) and yet enters a new joint venture (in December 2020) with Gazprom Neft for onshore blocks in the Gydan Peninsula (Gazprom Neft, 2020a; S&P Global, 2020c). In addition, it resumes Arctic exploration in Alaska (S&P Global, 2020e).

In Norway, independents Wintershall Dea and Vår Energi win respectively further 16 and 10 exploration licences, including the Norwegian and the Barents Sea (Vår Energi, 2021; Wintershall Dea, 2021).

All in all, Arctic oil and gas development has proven to be resilient even in the face of the COVID crisis, defying the odds of vanishing demand in a post-COVID world and previously existing sanctions against Russia, following the Crimea crisis of 2014.

Green Transition and climate change risks

As a result of an imminent green transition, companies involved in the production of fossil fuels face a higher risk of operating assets that will become stranded in the foreseeable future. Whether the green transition will mean that demand for fossil fuels will vanish in one, two, three or more decades remains uncertain and energy companies appear to be decided to diversify their portfolios.

However, most oil and gas producers are not abandoning their positions all at once some and are, in fact, continuously rebalancing their portfolios, through joint ventures and other agreements that help them mitigate the risks. In general, oil and gas producers appear to be juggling to secure mid- to long-term shareholder value, manage reputational risk and avoid falling into obsolescence.

Climate change also poses risks to oil and gas operators, as – paradoxically – heatwaves in northern areas reduce the number of days when winter roads can be used, and as thawing permafrost threatens the mid- to long-term integrity of equipment (S&P Global, 2020d).

Potential strategies to attract investments to the Greenlandic oil and gas sector

To attract the investors' interest in developing Greenland's oil and gas resources, a starting point is to re-assess the comparative advantages of its take structure relative to other Arctic territories.

However, an attractive take structure may be necessary but insufficient to attract investors, as there are other established regions in the Arctic offering better conditions with respect to important elements such as infrastructure and the overall geological knowledge of basins. Additional efforts, such as climate compensation may play an important role to brand Greenland as a climate-responsible territory.

Furthermore, there is a need to develop a comprehensive risk assessment, which accounts for the multi-dimensional implications of developing oil and gas in Greenland. This includes, but is not limited to, the geo-political and environmental implications of associating with potential entrants, which could be outside the more traditional scope of major oil and gas producers.

Can Greenland's oil resources be exchanged to carbon offset projects?

Carbon offsets are a market mechanism by which entities emitting carbon and other greenhouse gases compensate their direct emissions with reductions taking place elsewhere. In practice, an industrial activity may be limited in its ability to manage or reduce its *direct* carbon footprint but can instead offset it through the financial support to projects that reduce carbon and greenhouse gas emissions, thereby *indirectly* reducing its carbon footprint (see Figure 49).

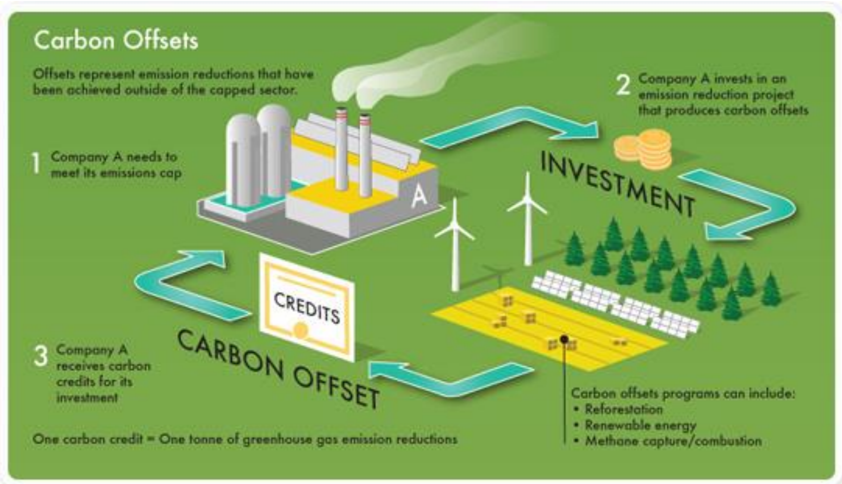

Figure 49: Schematic representation of a carbon offsetting mechanism. Source: Greenfact (Greenfact – All about renewables)

For a carbon offset mechanism to be successful, it is fundamental that the offset is validated and leads to effective reductions.[19] However, a general limitation to this kind of mechanisms is the fact that a carbon emission will not be simultaneously offset, i.e., there will be an inherent lag between the moment in which the emission and the offset take place.

In the oil and gas industry, there is one recent (probably the first) example of a carbon-offset crude oil delivery taking place between an upstream producer (Oxy) located in the Permian Basin (USA) and a large industrial consumer in India (Reliance Industries) (Veazey, 2021).

Oxy's subsidiary OLCV arranged in conjunction with Macquaire (a financial services company) the delivery of two million barrels of "carbon-neutral oil" or "climate-differentiated crude oil". In this context, carbon-neutral oil is to be understood as a structured transaction resulting in the offset of an amount of carbon dioxide equivalent to that associated with the production, delivery and refining of the crude oil and the use of the resulting product through the retirement of carbon offset credits (OLCV, 2021).

Required IRR for projects in Greenland

On average, financial sources indicate that oil and gas industry projects have recently settled at an average Internal Rate of Return (IRR) of 15-20%, after improving project execution in recent years. Earlier projects – despite higher prices – tended to result in more moderate returns of approximately 10%.

Complex oil and gas projects in regions such as the Caspian Sea and the Arctic had been previously characterized by massive blowouts. However, improved discipline together with a stronger focus on brownfield, expansion, tie-back and - not least - smaller projects have increased cost-efficiency.[20] Among the projects praised by its on-budget executions, despite its complexity is Yamal LNG, which has been led by Russian independent Novatek (Venables, 2018).

Furthermore, industry sources highlight that projects operating in high-price environments tended to suffer of upstream cost inflation too, as Naumov & Toews (2016) confirm. Technological progress could also explain that despite oil prices are lower than, say, 10-12 years ago, some of the most complex developments still are profitable.

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[19] Verra, a US-based tax-exempt organization is one of the organizations devoted to creating, managing and validating carbon offsets.

[20] Tie-back is an engineering process connecting an untapped satellite oil field to an existing production center. Source: What Is The Foremost Consideration For Subsea Tiebacks? (audubonecompanies.com).

In this respect, a good point of comparison for potential forthcoming Greenlandic projects – a benchmark of sorts – is presented by the Russian government's inverse relationship between the royalty rate charged and a target IRR.

Unlike other Arctic territories, which operate under concessions, Russia has both concession-type arrangements and production sharing agreements (PSAs). Under the PSA framework, the share of per-oil profit (in addition to the royalty rate) depends on the realized IRR (Alegre et al., 2015).

As Table 20 shows that the most demanding projects, those operating in Arctic conditions (group 4) have a target IRR of 22% and obtain a royalty rate of 5%. Sub-Arctic projects, corresponding to groups 2 and 3, have lower IRR targets and obtain higher royalty rates. Judging by the inverse relationship between targeted IRR and royalty rate, the tax structure incentivizes risk taking.

Group	Location	IRR target	Royalty rate
1	Baltic/Azov seas	16.5%	30%
2	Shallow waters of the Black Sea, Pechora and White Sea, southern part of the Okhotsk Sea, offshore Sakhalin	18.5%	15%
3	Deep waters of the Black Sea, the northern part of the Okhotsk Sea, southern part of the Barents Sea	20.5%	10%
4	Offshore projects in the Arctic (includes Kara Sea), the northern part of the Barents Sea, the Eastern Arctic	22%	5%

Table 20: Tax rates for Russian offshore. Source: (Henderson & Grushevenko, 2019) *citing the Russian Tax Service*

As an example, Alegre et al.(2015) indicate that investors in the Sakhalin-2 project (where Gazprom has a joint venture with ExxonMobil and Shell) pay a royalty rate of 6%. As they operate under a PSA, the maximum contractor/state percentage split is 90-10, if the IRR is below 17.5%. Conversely, the minimum contractor/state percentage split is 70-30, if the IRR is above 24%.[21]

[21] Alegre et al.(2015) further note that Russia's fiscal regime is changing frequently and, as can be noted, they mention a 6% royalty for the Sakhalin-2 project, while according to Table 20, such a project should pay a 15% royalty, as it is Sub-Arctic.

9 Potential value of oil reserves

The following chapter combines the above reserve estimates and oil price scenarios into a simple analysis of the potential value of Greenland's oil reserves that can be extracted within the next 30-40 years. The current analysis focuses primarily on the economic costs and benefits of offshore oil extraction, and therefore does not focus on onshore oil, nor natural gas production. This is because estimated onshore oil reserves are not assessed to be large enough to support a full oil development effort alone, and with respect to gas, this would require the establishment of very expensive LNG terminals to become a major exporter, and this is not deemed to be a realistic first step in Greenlandic hydrocarbon development.

9.1 Methodology

The overarching steps of the methodology involved:

- Estimating the quantity of realistic recoverable oil reserves by arriving at a number of potential projects
- Application of proxy CAPEX and OPEX figures for each of the potential projects
- Apply assumptions regarding project timeframes and production profiles
- Utilisation of the three oil price scenarios to determine Internal Rates of Return (IRR) for each of the projects given varying oil prices.
- Calculation of Greenland's portion of Net Present Values (NPVs) for project scenarios that meet a minimum assumed IRR requirement for oil companies.

Quantity of recoverable oil reserves

Estimating the quantity of recoverable oil reserves was done by undertaking an assessment of the realistic number of projects that can be initiated within the next 30 years in both Northwest and Southwest Greenland, i.e., it is not realistic to assume that all oil resources can be developed, even if oil prices prove to be high. Based on reserve input information supplied by Nunaoil A/S, and the application of Economic 'cut-offs' based on assessments by Nunaoil A/S, recoverable reserves estimates were arrived at for each of these projects. Note that reserves in NE Greenland were not considered due to the anticipated significant costs associated with their development, and thus the unlikelihood of these resources being the first to be developed.

Based on recent resource estimates for offshore oil production in Southwest Greenland and assumed minimum field sizes with 250 million barrels of recoverable oil (mboe), Nunaoil A/S assessed that it would be realistic to start exploration for 3 projects within the next 10 years. Offshore in NW Greenland, where ice conditions would require more capital intense technologies, the assumed minimum field size was 500 mboe, and it was assessed that it would be reasonable to assume start one such project within the next 10 years. The assumptions regarding field size, water depth, and reservoir depth are displayed in Table 21.

Parameter	unit	SW1	SW2	SW3	NW
Field size (assumed extractable)	mboe	250	250	250	650
Water depth	meters	0 - 200	0 - 200	200 - 1,500	0 - 200
Reservoir depth	meters	2,000	3,000	4,000	3,000

Table 21: Field and reservoir characteristic for the 4 fields

Proxy CAPEX and OPEX figures

Through discussions with various actors, Nunaoil A/S has developed CAPEX and OPEX estimates for potential projects depending on the field location and size, as well as water and reservoir depth. The values used for each of the 4 fields are displayed in Table 22.

Parameter	unit	SW1	**SW2**	**SW3**	**NW**
Upfront and restoration costs					
Exploration	Mio. USD	$400	$520	$800	$750
CAPEX	Mio. USD	$5,800	$6,200	$6,600	$16,800
Restoration	Mio. USD	$600	$650	$700	$1,200
Operating costs					
OPEX	USD/boe	$15	$17	$20	$25
Transport	USD/boe	$3	$3	$3	$6

Table 22: Upfront, restoration, and operation cast assumptions utilised in the IRR analysis of hypothetical oil fields SW and NW of Greenland.

In SW Greenland, it is assumed that oil production would be free of sea ice year round but would be located in a region with passing icebergs. The CAPEX & OPEX figures used thus reflect a floating production storage and offloading (FPSO) system, which involves a floating unit (often a converted oil tanker) that can produce oil from sub-sea wells via flexible pipelines, and thereby reduce the need for fixed structures (Bluewater, 2021). These numbers include construction of an FPSO system, as well as subsea development. The costs for the SW fields are anticipated to increase slightly from SW1 to SW3 due to the increasing water and/or reservoir depths.

A hypothetical project off the shores of Northwest Greenland, where there is a great deal of sea ice, is assumed to instead require a Gravity Based Structure (GBS). In addition, icebreakers will need to be employed for portions of the year, and tankers that can cope with these conditions will be required during the production phase. These aspects raise the CAPEX and OPEX figures considerably. In addition, to the construction of the GBS structure, subsea development, tankers and icebreakers, additional onshore facilities would also be required in NW Greenland to support the activities (for example a heliport), and these figures are also included in the CAPEX values.

Project timeframes and production profiles

To determine annual cash flows, it was necessary to undertake assumptions regarding the duration of various phases of the oil projects, i.e., how long preparation, exploration, and construction periods will take, as well as when production will start and cease. Based on inputs from Nunaoil A/S, durations for each period were estimated. It was assumed that the first project off SW Greenland would start preparations in 2022, with the 2nd project starting 3 years after in 2025, and if all went well with the first two, a third could start in 2028. Given the more complicated nature of the project off NW Greenland, it was assumed to first start in 2025. Due to the significant sea ice in the area, it is assumed that exploration and construction would take longer than in SW Greenland. The project timeframes assumed in the analysis are displayed in Table 23.

Parameter	unit	SW1	SW2	SW3	NW
Assumed start year	year	2022	2025	2028	2025
Preparation period	years	3	3	3	3
Exploration period	years	6	6	6	7
Construction period	years	6	6	6	8
Production period	years	20	20	20	20
Restoration / closing period	years	3	3	3	4

Table 23: Standard assumptions utilised in IRR analysis of hypothetical oil field SW of Greenland.

Annual oil production from the 4 hypothetical projects was assumed to follow a somewhat standard oil production profile, i.e., a steep ramp up phase, proceeded by a period of peak production, followed by falling production. The assumed production profile, expressed in oil annual production as a % of total production, used for all 4 projects is displayed in Figure 50.

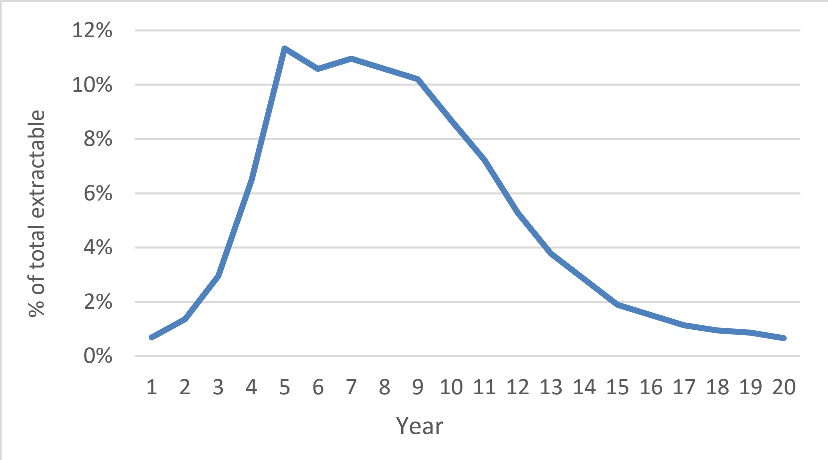

Figure 50: Simplified assumed production profile for a hypothetical oil field NW of Greenland.

Oil prices utilised

One of the most important parameters in such an analysis is the oil price, and the central price used was the Ea assessment for the potential development of oil prices from section 7.3. As was detailed previously, this price series is based on a weighted average between the 2020 World Energy Outlook Stated Polices Scenario (STEPS) and the Sustainable Development Scenario (SDS). Variations using both higher (based more heavily on STPES), and lower oil prices (in line with SDS) were also undertaken (see Figure 51).

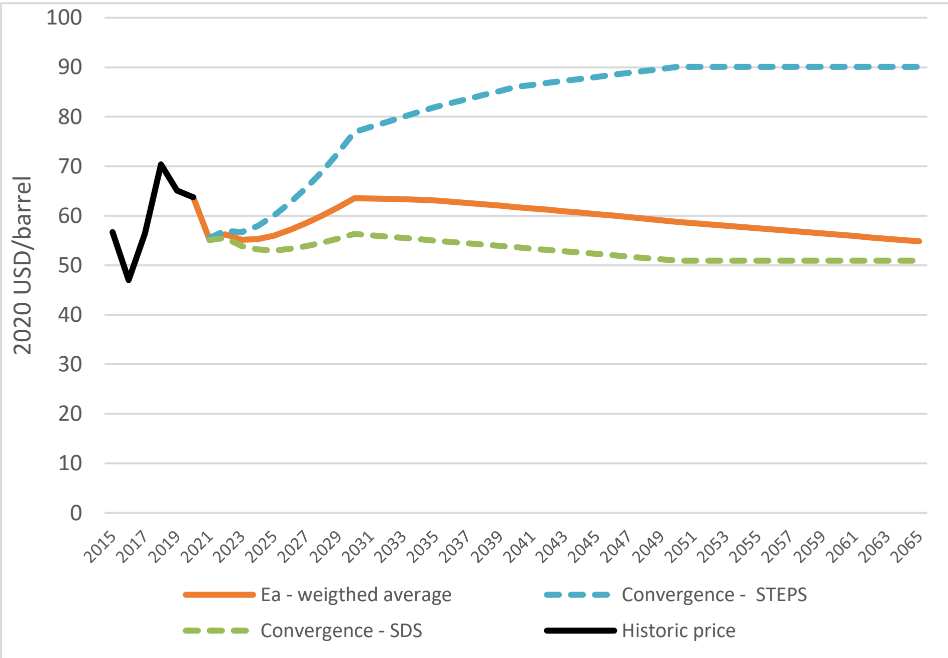

Figure 51: There oil price series utilised in the IRR analyses (2020 USD/boe).

Discount rates, IRR minimums, and Government take
In undertaking NPV calculations, discount rates used by oil companies and governments are very different, as oil companies often use rates well in excess of 10%, while governments often discount cash flows many years into the future at rates of 3 or 4%. The methodology therefore involved first undertaking Internal Rate of Return (IRR) calculations for each of the projects given varying oil prices.

For those projects that met a bare minimum threshold deemed necessary for an oil company to undertake a project, an NPV calculation of the Greenlandic portion was then undertaken. For the purposes of this analysis, a bare minimum of 10% was used. However, this element has not been researched in depth, and as was noted in the previous chapter, oil companies operating in the Arctic currently have IRR targets considerably higher than 10%, thus it could be argued that this this cut-off is set too low. In fact, all the listed target IRRs were in regions with lower government take rates than those in Greenland.

Under the current take structure in Greenland, it is Ea's understanding that oil companies essentially do not pay tax until they start generating a profit on their investments. Within the current analysis, at the point in time when a project became profitable for the oil company (i.e., non-discounted accumulated oil revenues were greater than all non-discounted investments and assumed restoration costs), the Greenlandic portion of net profits from that point forward were summed and discounted at a rate of 3%. It was assumed that from this breakeven point, the Greenlandic take would be 33.4% of net revenues.

9.2 IRR and NPV Results

An example of the annual non-discounted cash flows for the first project off the coast of SW Greenland is displayed Figure 52. The coloured bars depict the annual costs/revenues according to category, while the black dashed line displays the net annual cashflows. The oil revenues in this example are based on the central oil price. The red dashed line meanwhile depicts the accumulated cash flows (right axis). All values are in millions of USD 2021 (i.e., real terms).

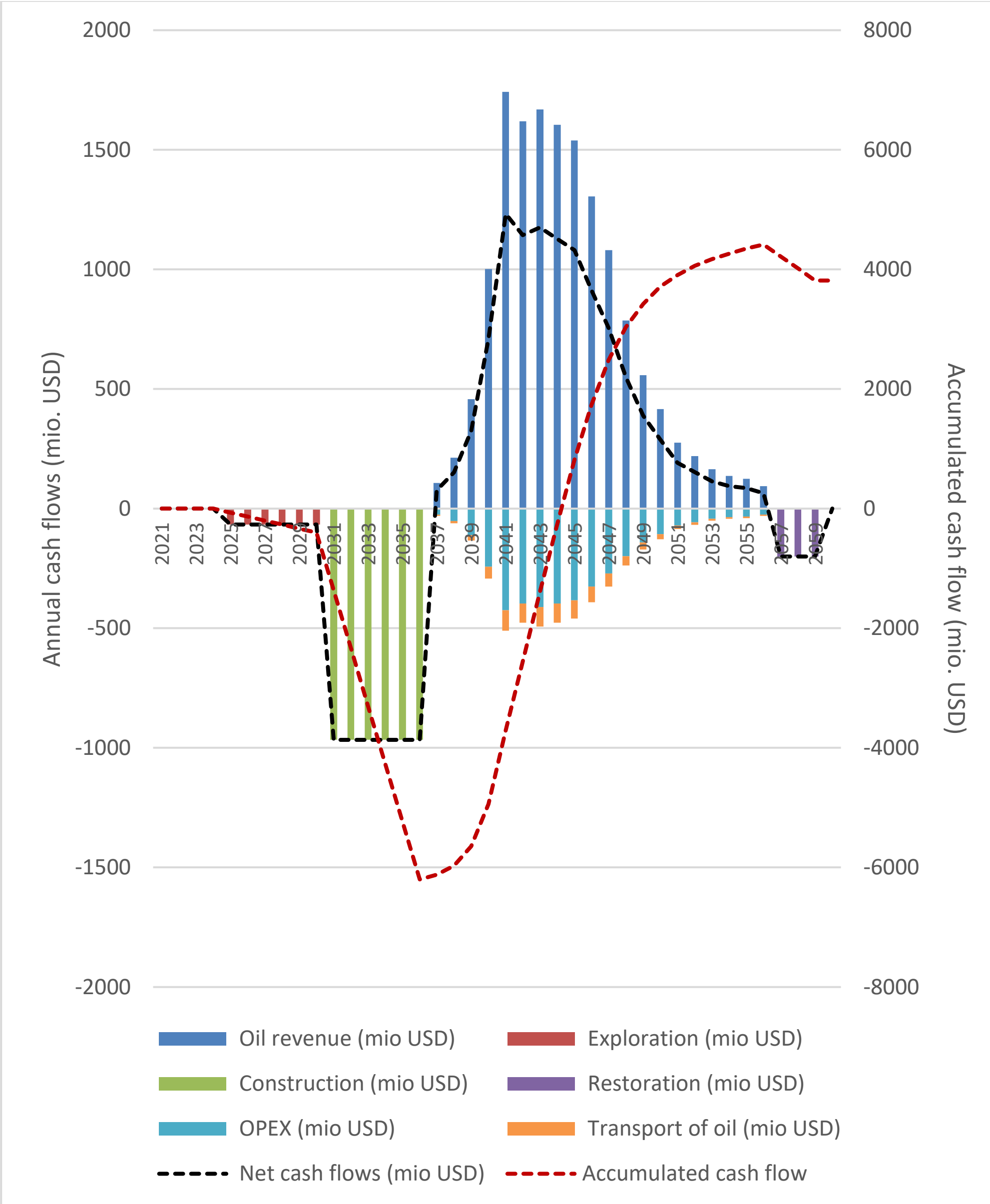

Figure 52: Non-discounted cash flows in millions of USD (real terms) for the first project off the SW cost of Greenland (SW1). The left axis expresses annual values, while the right axis depicts the accumulated cash flows.

The internal rate of return for the above project in this oil price scenario is 4.7%. I.e., with a discount rate of 4.7%, the NPV of the project would be 0.

The figure below displays the IRRs[22] for all 4 projects given 3 different oil price scenarios.

[22] Tax implications are not incorporated in the simple project IRR calculations

Figure 53: Internal rate of return (IRR) for 4 hypothetical oil projects in Greenland given 3 different oil price scenarios.

As can be seen from Figure 53, the calculated IRR did not exceed 10% for any of the projects, even in a scenario where the oil price averaged $88/barrel during the oil production years. In fact, even if the desired IRR level were lowered to 7.5% for an oil company, only the first 2 projects off the SW coast of Greenland would exceed this threshold, and only in a scenario with high oil prices.

These findings illustrate that given the assumed field sizes and CAPEX & OPEX costs, only an oil company that forecasts oil prices in excess of $90/barrel and is willing to accept anticipated returns well below the norm, would be likely to undertake investment in Greenland. In such a scenario, the NPV of the Greenlandic portion of the SW 1 project would be 1.66 billion USD, while the NPV of the SW 2 project would be 1.40 billion USD.

The figure below displays the annual discounted cash flows (at 3%) for the Greenlandic portion of oil revenues for SW 1 in a scenario with high oil prices. Note that the Greenlandic portion of discounted annual net revenues start in 2044, as this is the year that the oil company is assumed to have recovered all its investments.

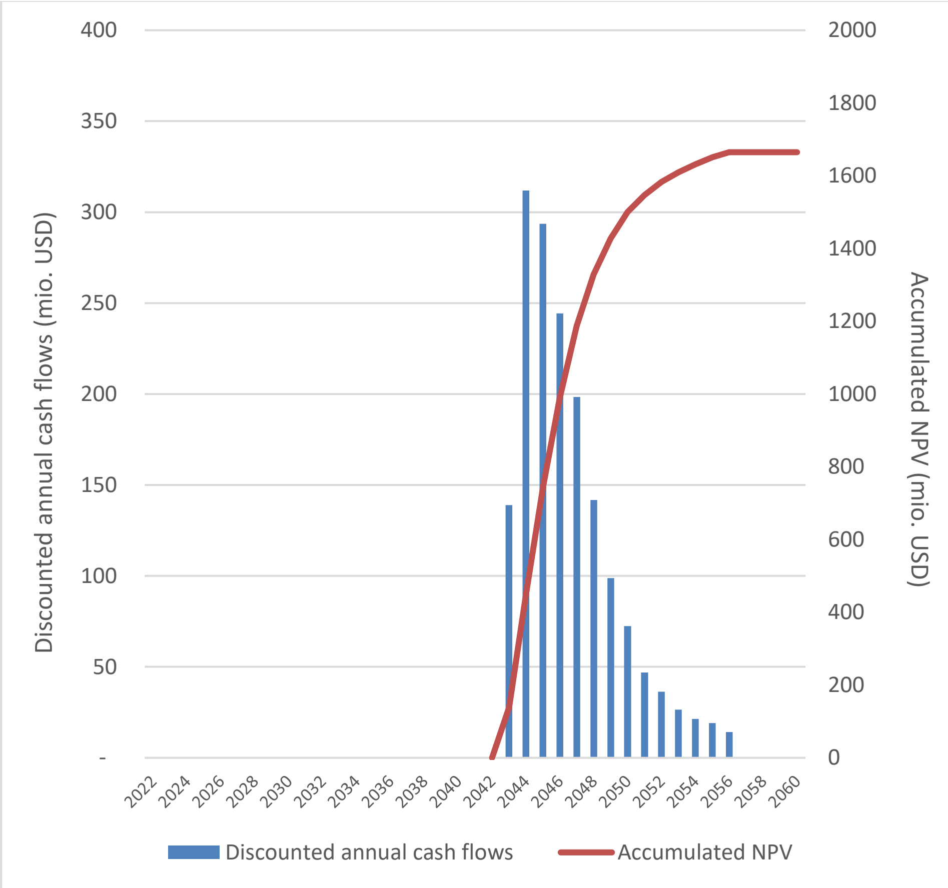

Figure 54: Greenlandic portion of oil revenues for SW 1 discounted at 3% in a scenario with high oil prices.

Altered CAPEX

The analysis above illustrates the unlikelihood of an oil company investing in oil production in Greenland given the assumptions utilised in the analysis. Given the large CAPEX values associated with oil investment in Greenland, a sensitivity analysis on the CAPEX assumptions was undertaken to see the effect on IRR and NPVs. In this exercise, CAPEX values were decreased with 25% in the low CAPEX scenario and increased with 25% in the high CAPEX scenario. The values utilised for the 4 hypothetical fields are displayed in Table 24.

CAPEX	unit	SW1	SW2	SW3	NW
High	Mio. USD	$7,250	$7,750	$8,250	$21,000
Standard	Mio. USD	$5,800	$6,200	$6,600	$16,800
Low	Mio. USD	$4,350	$4,650	$4,950	$12,600

Table 24: Standard, High, and Low CAPEX values utilised in the IRR analysis of hypothetical oil fields SW and NW of Greenland.

The resulting IRRs for the SW 1 project given varying CAPEX and oil prices are displayed in Figure 55. Given the considerable size of the CAPEX investments, it is not surprising that the IRRS are significantly improved with lower CAPEX. As can be seen from the figure, with a 25% reduction in CAPEX values, a situation with higher oil prices would provide a project return in excess of 12%.

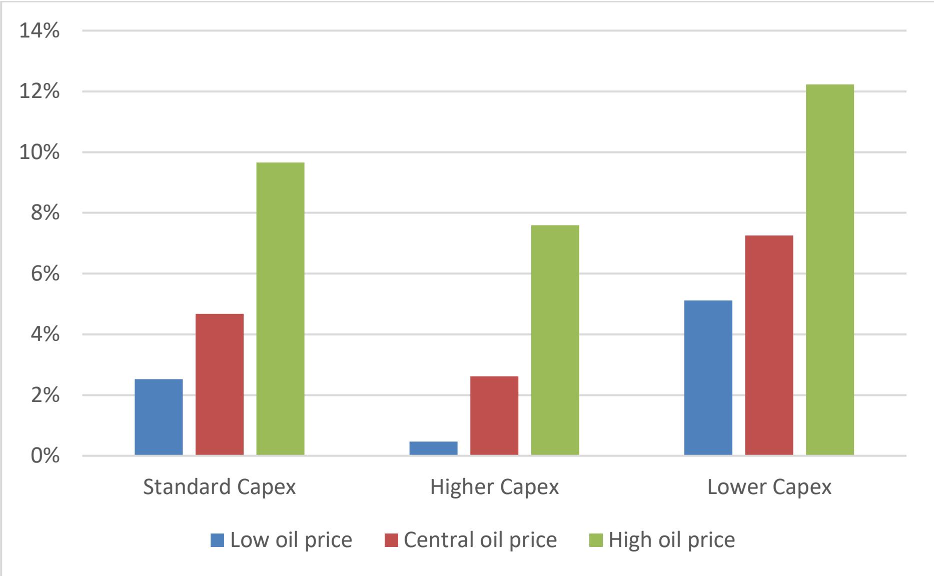

Figure 55: IRRs for the SW 1 project given varying CAPEX and oil prices

The corresponding IRRs for the NW project given varying CAPEX values and oil prices are displayed below.

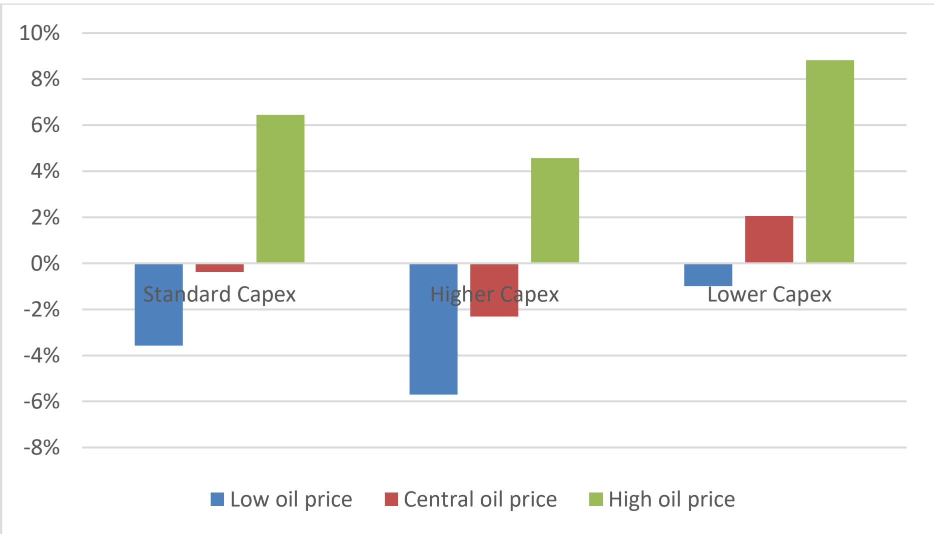

Figure 56: IRRs for the NW project given varying CAPEX and oil prices

None of the projects reached the minimum 10% IRR threshold in a situation with standard CAPEX values. The following figure therefore displays the IRRs for the various projects given varying oil price scenarios solely for a situation with lower CAPEX.

Figure 57: Internal rate of return (IRR) for 4 hypothetical oil projects in Greenland given 3 different oil price scenarios assuming lower CAPEX.

In a situation where CAPEX is reduced by 25% relative to the standard assumed values, and in a scenario assuming oil prices averaging close to $90/barrel, the first two hypothetical projects of the SW coast of Greenland would generate an IRR in excess of the assumed 10% bare minimum.

The table below displays the potential Greenlandic NPV for all 4 projects assuming both low CAPEX and high oil prices.

	Project IRR	Greenlandic NPV (billion USD)
SW 1	12.2%	$1,9
SW 2	11.1%	$1,6
SW 3	9.5%	$1,3
NW 1	8.8%	$3,1
Total all projects		$8.0
Total for projects with min 10% IRR		**$3.6**

Table 25: Standard, High, and Low CAPEX values utilised in the IRR analysis of hypothetical oil fields SW and NW of Greenland.

Conclusions

Given the assumed standard CAPEX and OPEX values and oil quantities utilised in the current analysis, it is not likely that an oil company would find it economically attractive to undertake oil investments in the hypothetical projects described within the current analysis.

If an oil company both assumed that oil prices would average roughly 90 USD/barrel (in real terms) for the production period and could achieve CAPEX roughly 25% lower than the standard values assumed here, then the Greenlandic NPV could be roughly 3.6 billion USD.

Drawbacks of analysis

It is important to note that the input data for the current IRR analyses was not very detailed, and there are several layers of detail for various components that were not available. It is therefore important to state that the findings here do not conclude that there are no fields in Greenland that may be economically attractive to explore. However, this quick screening does highlight the potential challenges that developers may have in finding economically attractive projects in Greenland.

10 SWOT analysis and conclusions

The two core questions that Ea was posed with answering in this analysis were:

1) What is the likelihood of Greenland can become an oil exporting country in the future?
2) And what are the economic potential and environmental challenges?

Due primarily to a series of economic challenges, some of which are related to the local and global environment, the analysis undertaken within the current study indicates that it is unlikely that Greenland can become an oil exporting country in the future. However, Ea suggest that there is a 3rd question that bears answering as well, namely:

3) What are the consequences of Greenland maintaining an ambitious and offensive oil strategy?

I.e., it is almost certain that Greenland is home to significant oil and gas resources, so what are the benefits and drawbacks of keeping the door to potential investment open, particularly if circumstances change in the years to come.

Whether or not to maintain an offensive oil strategy is a political decision that the people of Greenland should undertake. To support this discussion, a brief SWOT analysis was undertaken, the results of which are summarised below.

Strengths

- It keeps an option open for Greenland. Oil prices have historically been very difficult to forecast, and if very high prices occur again, Greenland would be able to capitalise
- Attractive cooperation partner for US, China, Russia, and others.
- Time, effort, and funding spent on developing the current knowledge base are not lost.

Weaknesses

- If interest continues to be very low, it could be a futile effort, and would therefore take focus, funding, and efforts from other strategic areas.
- Continuing to promote the possibility might be perceived as unrealistic government dreaming.

Opportunities

- Ensures that opportunities for workplaces and income streams are not lost, even if the chances of largescale oil export are small.

Threats

- Greenland has a chance to be branded as an "Environmentally friendly state". An ambitious oil strategy might jeopardise this in the eyes of those in Greenland, and abroad, particularly amongst younger people.
- If development is undertaken, the risk of environmental damage and economic effects on fishery, hunting and tourism of a large oil spill are quite low, but if a spill did occur, the effects could be catastrophic.

Annex 1 – Data, input, and methodology for

Data and input

The input to the assessment project is all available data acquired by industry, academia, GEUS, the Ministry and NUNAOIL, and interpretations from industry, GEUS and NUNAOIL and mapped leads/prospects by industry, GEUS and NUNAOIL.

Where data from Greenland is not available, data from analogue areas e.g., the conjugate margin of Norway and Canada have been used.

As an initial part of the project, a post-well analysis has been performed on all the drilled wells to establish the failure mechanism for a dry well or alternatively the success of a technical discovery. This also gives the first indications of where there are high risk elements in the individual play segment.

Since the Greenland Continental Shelf is more than 2 million km^2 and consists of unique geological provinces, the shelf area is segmented into seven assessment units, each characterised by their unique geological evolution. A map displaying the seven assessment units is shown below and the individual size of each assessment unit is shown in the table below.

Order	Assessment Unit	Area (km^2)	Status
1	Davis Strait and Labrador Sea	470,886	Finalised
2	Baffin Bay	159,062	Finalised
3	Nuussuaq Basin and Disko West	175,430	Finalised
4	Northeast Greenland	412,216	Expected release: spring of 2021
5	Central East Greenland	369,042	Expected release: autumn of 2021
6	Southeast Greenland	515,039	Expected release: end of 2021
7	North Greenland	329,558	Expected release: spring of 2022
Total area		**2,431,233**	

Table 26: Order of assessment chronology, name of assessment units, their size and their status for delivery.

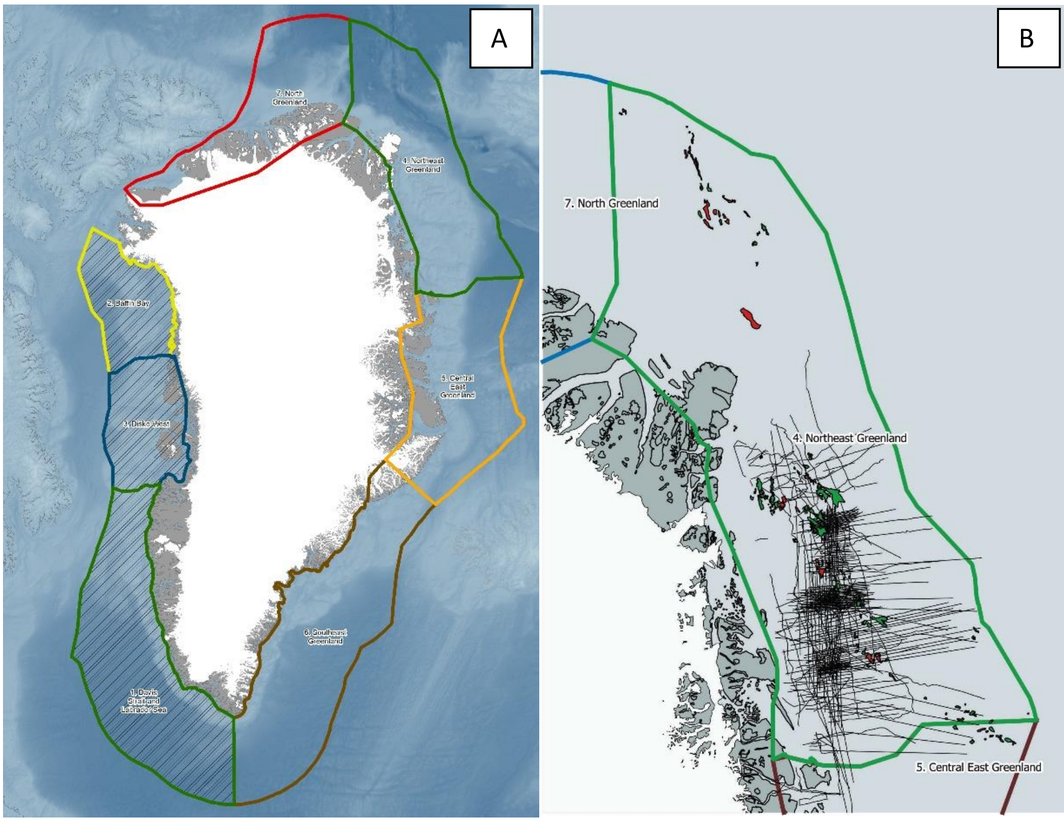

Figure 58: A) Map showing the seven assessment units for the whole of Greenland resource assessment project. The three assessment units with the hatched symbology have been finalised at time of writing. B) Map zoomed into AU4 – Northeast Greenland with all the Norwegian oil and gas fields of the North Sea and Mid Norway inserted to show the scale of some of the assessment units.

Assessment Process - Methodology

The resource assessment project uses a quantitative play-based methodology, a methodology internationally recognised and the *a priori* standard in the oil industry today and used by the largest international oil companies in the world.

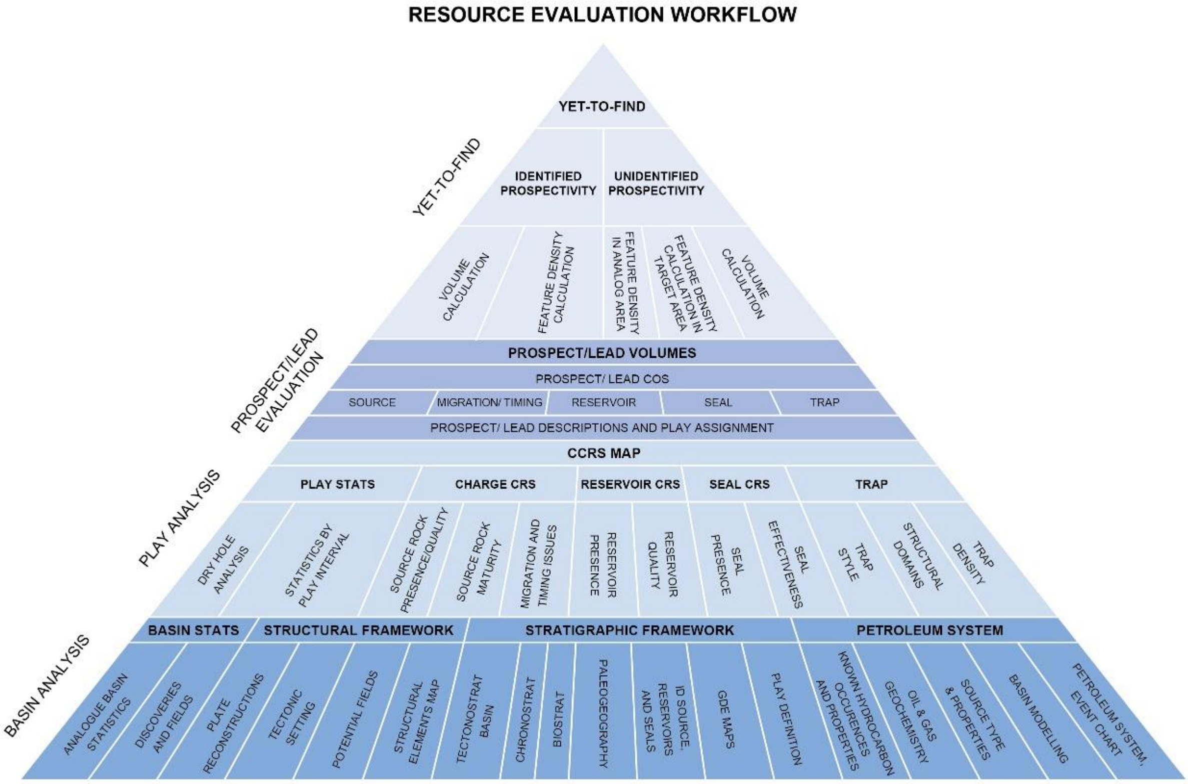

Figure 59: The resource assessment follows the workflow as depicted by the resource evaluation triangle. To proceed to the next level all elements in the level below must be addressed, so all elements in the Basin Analysis must be dealt with before moving to the Play Analysis stage.

The project uses the GIS-PAX Player® software ArcGIS plugin and hence the analysis is done on geospatial maps and calculations are done via maps and surfaces within ArcGIS.

From the onset of the project start it was decided to only include mapped structural traps (3-way and 4-way structures) and *not* include stratigraphic traps and fractured basement due to the complexity and uniqueness of these types of traps.

Based on the regional geological knowledge, a total of 17 play intervals are present on the shelf area, but not all plays are present in every assessment unit.
Basin evaluation is the basic activity describing the structural and stratigraphic framework leading into construction of Gross Depositional Environment (GDE) maps and identification of source rocks, reservoirs and regional seals that form the basis for definition of the plays. Figure 60 below displays an example of the

regional stratigraphic scheme used to separate the geological succession into 8 play levels on the West Greenland Shelf.

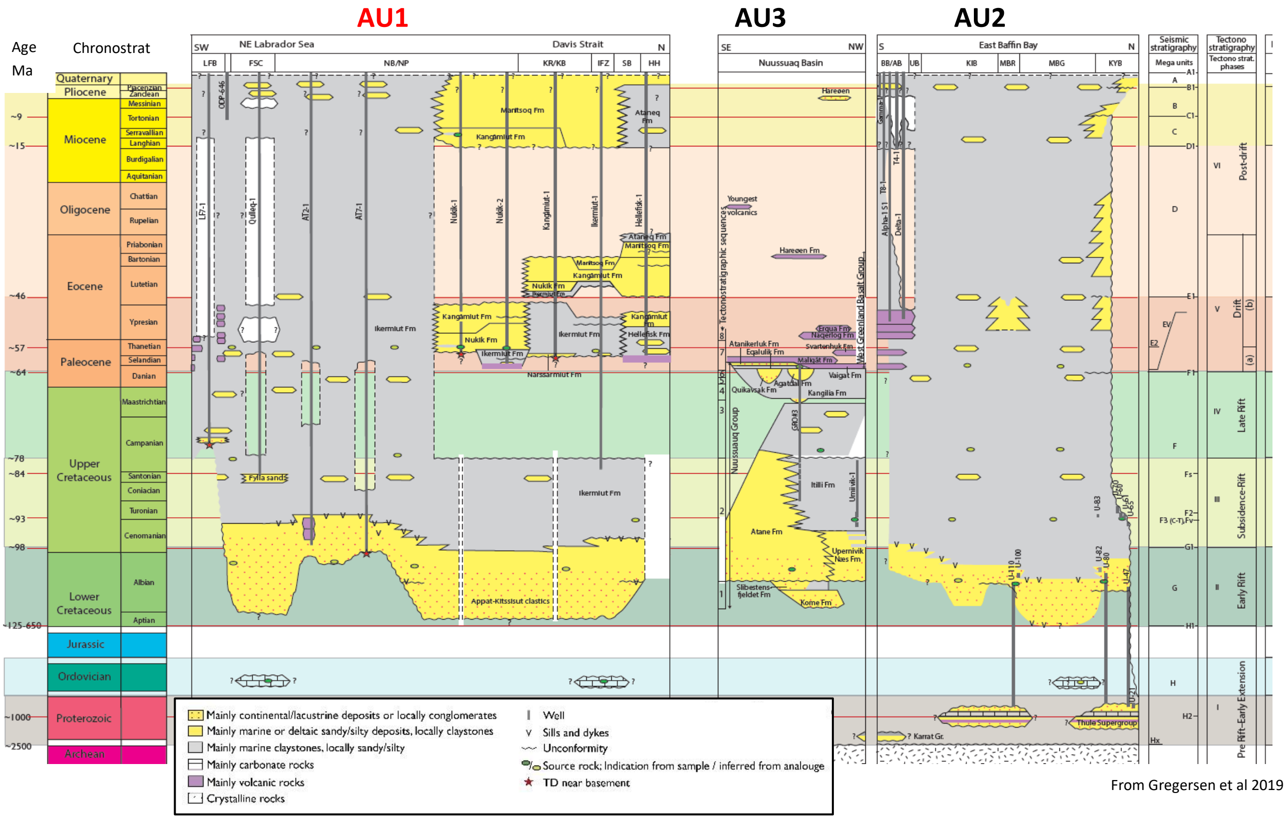

Figure 60: Regional stratigraphic scheme used to divide the succession into play levels, here for the West Greenland Shelf (AU1-AU3) where there are a total of 8 plays.

A vital part of a play-based resource assessment is estimating source rock maturity and charging, and for this a new regional 3D basin reference model has been constructed for each assessment unit.

The results from the basin evaluation feed into the play analysis, and for each play interval a set of numeric Common-Risk Segment (CRS) maps and Composite Common Risk Segment (CCRS) maps are constructed based on all available geological and geophysical knowledge. Both onshore and offshore and analogue areas are populated with risking values.

The following play risk elements have been assessed: Reservoir Presence (based on GDE maps), Reservoir Effectiveness (based on depth to interval maps), Seal Effectiveness (based on overburden thickness maps) and Charge-Migration (based on maturity and drainage maps).

In case of more than one source rock (which is the case for most of the assessment units), a multiple charge scenario is applied for each play. This means that for each play a specially designed composite charge workflow is applied to assess the charge-migration risk.

The project uses a split risk methodology – *play risk* and *conditional risk* – making it possible to assess which data collection will de-risk the most volumes and hence giving an estimate of which data collection has the most value commercially. In a split-risk method, each polygon of the CRS maps is given two risk values – one for the *play risk* – the chance of the play being successful within that specific polygon and a *conditional risk* – the chance that once the play is successful – what is the chance that it is successful everywhere within that polygon (representing repeatability).

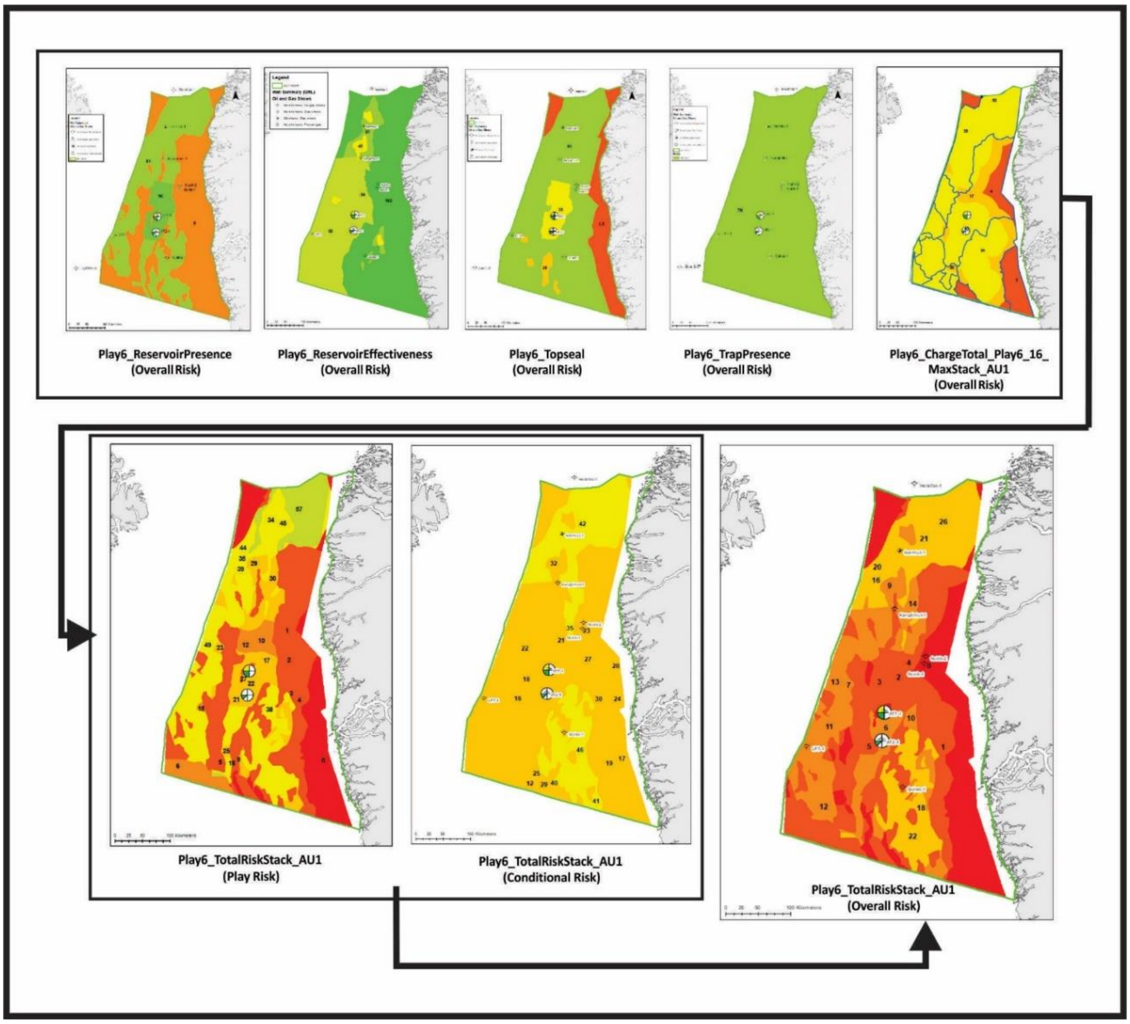

Figure 61: Workflow schematics for how a Total Risk Stack is constructed for each play within the assessment unit AU1.

Volumes for leads mapped by the industry, GEUS and NUNAOIL is integrated into the play evaluation and the identified prospectivity is calculated. For the volume calculations of individual leads the oil-water contact has been picked halfway between the top of the structure and spill point, since source rock analysis does not support fill-to-spill scenarios.

The known prospectivity appears from integrating the calculated identified lead volumes with the CCRS maps providing the risked volumes for the mapped leads.

The Yet-to-Find (YTF) analysis is based on a feature (lead) density calculation approach for each of the identified play intervals calibrated with data from the most extensively explored previous licence areas (analogue areas).

Based on these analogue areas, the unidentified prospectivity is calculated for the underexplored areas. Once the identified and unidentified prospectivity has been calculated, the Mean Case Risked MMBOE (million barrels of oil equivalent) Recoverable per unit can be estimated and the roll-up of all the play intervals provide the Total Mean Case Risked MMBOE for the assessment unit. Dividing the assessment area into blocks of equal area, normalizes YTF/area and allows to point out which of the blocks that are most prospective (Figure 63).

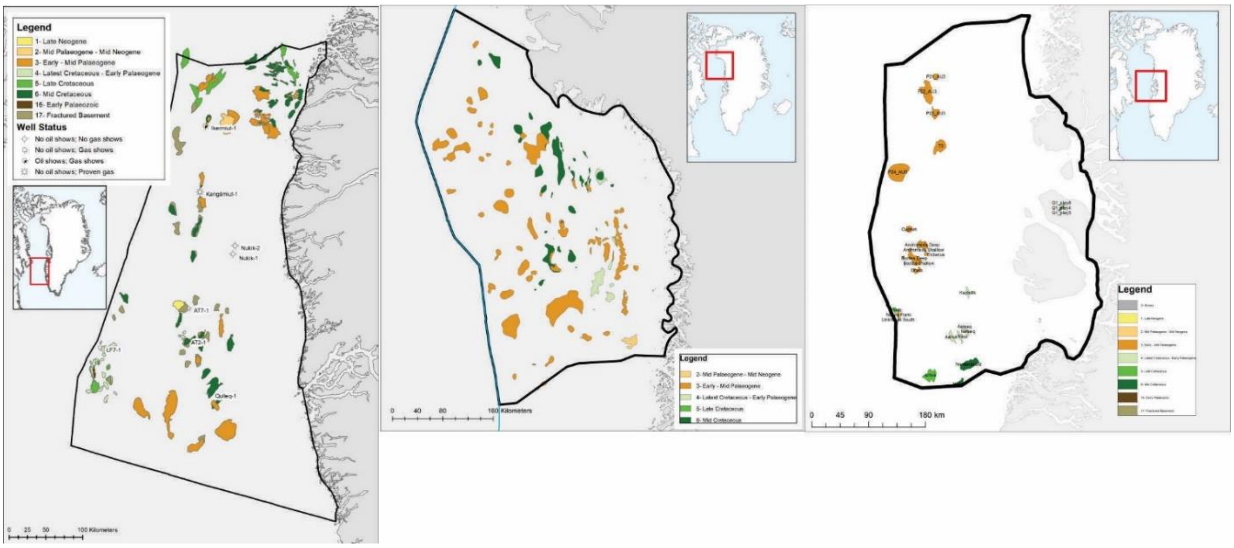

Figure 62: Maps of the identified (mapped) leads within each assessment unit (AU1 - North, AU2 and AU3) and split into their respective play interval (the different coloured blobs).

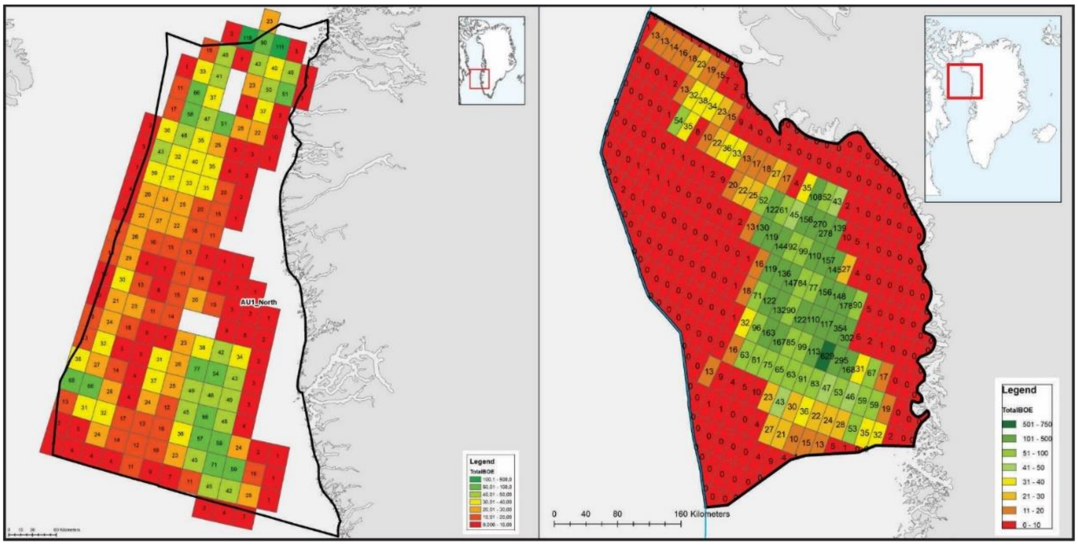

Figure 63: Total risked mean case MMBOE/Block recoverable for AU1 and AU2. Green colours are high values while red is low.

Besides a Total Mean Case Risked MMBOE, the play-based methodology can also provide estimates of each individual play and point to which of the play intervals that are most prospective and should be focus of exploration.

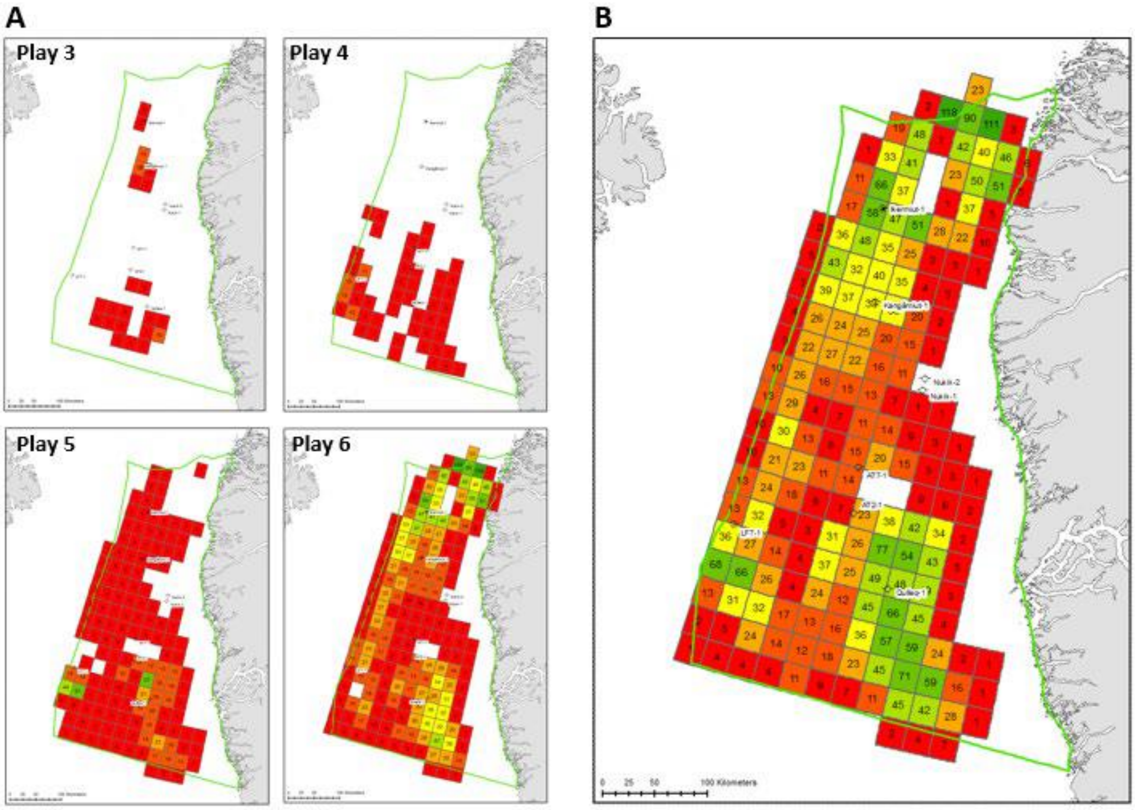

Figure 64: An example from AU1 northern area of how the risked mean recoverable (MMBOE) per block is split into individual plays (A) and the total roll-up for all four (3-6) plays (B).

Yet-to-Find and Volumetrics

At present, Yet-to-Find (YTF) volumetrics has been estimated for three assessment units (AU1, AU2 and AU3) and represents the whole of the western part of the Greenland Continental Shelf.

The first step in the Yet-to-Find assessment is to make Gross-Rock Volumes for the leads mapped by the industry, GEUS and NUNAOIL. Calculations of Gross-Rock volume were made in the software package Player® based on area-depth pairs from the top of the structure to the spill point. Area-depth pairs were derived from either 1) mapping of the structures in Petrel (seismic software package) or 2) digitizing of closure and contour lines in ArcGIS from company reports.

For the hydrocarbon volume calculations, the following input parameters have been considered for all leads: 1) porosity, 2) gross and net sand thickness and net-to-gross ratio. 3) oil saturation, 4) oil formation volume factor, 5) recovery factor and 6) gas expansion factor.

These input parameters are based on well data, information about water depths, interpretation of petrophysical well logs, saturation curves and information from publications, etc.

The outcome is the unrisked Yet-to-Find result, which is then integrated with the risk derived from the CCRS maps and the resulting risked Yet-to-Find volumetrics is the outcome. It is the risked Yet-to-Find volumetrics which is the key result and the result from which any economical assessment is derived.

Annex 2 - Oil Spills in the Strategic Environmental Impact Assessment

Oil Spills in the Strategic Environmental Impact Assessment

The following section is copied from the Strategic Environmental Impact Assessment for the Baffin Bay in Northwest Greenland.[23]

Accidents – oil spills

"The accident due to the activities described above with the most severe environmental consequences is a large oil spill. Such oil spills may occur either during drilling (blowouts) or from storing or transport of oil. Nowadays, large oil spills are rare due to the technical progress and the improving HSE policies. However, the risk cannot be eliminated and in an area with the presence of sea ice and icebergs, such as Baffin Bay, the probability of an accident is increased. 12 Large oil spills have the potential to impact the marine ecosystem on all levels, from primary production to the top predators. A large oil spill represents a threat at population level (AMAP 2010), and the impacts may last for more than 20 years as documented in Prince William Sound in Alaska after the Exxon Valdez spill in 1989. Oil spills have the potential to drift with winds and currents and impact shores and waters far from the spill site. In case of a spill from a well in one of the licence blocks in the assessment area, coast and waters not only in Greenland but also in Canada will be threatened. Effects of an oil spill may also be intensified because of the much more difficult operating conditions for an oil spill response in the Arctic. Only 14% of the oil was recovered/burnt off during the Exxon Valdez oil spill and 25% during and after the Deepwater Horizon spill in the Gulf of Mexico. The ice is one major obstacle, the lack of infrastructure is another and the winter darkness is a third major factor contributing to reduce the efficiency of an oil spill response in the Baffin Bay. Recovery lasted more than 20 years in Prince William Sound. It will take much longer time in the Baffin Bay assessment area due to the Arctic conditions, and the more difficult and limited ways to clean up spilled oil there – with the risk of leaving much more oil in the environment – will also contribute to longer effects.

Primary production and plankton

It is expected that a surface oil spill in open waters far from the coast of the assessment area will have only low impacts on primary production due to the large temporal and spatial variation of the primary production. Localised high primary production may be reduced; however overall production will probably

[23] The full report can be found at: https://dce2.au.dk/pub/SR218.pdf

not be significantly impacted due to the large areas where the primary production takes place. The same may be true for localised concentrations of plankton and fish/ shrimp larvae if they occur in the uppermost part of the water column. However, on a broad scale, no or only minor effects are expected on these ecosystem components. If subsea plumes of dispersed oil are generated in the Baffin Bay area, as observed during the Deepwater Horizon-blowout, impacts on primary production, zooplankton and fish/shrimp larvae in the water column are more likely to occur compared with the surface spill situation.

Impacts on the seabed

Bottom-living organisms such as bivalves, crustaceans or fish are vulnerable to oil spills; however, no effects are expected in the open sea unless the oil sinks to the seabed. In shallow waters (< 10-15 m), highly toxic concentrations of hydrocarbons can reach the seafloor with possible severe consequences for local benthos and thus also for species utilising the benthos – especially walrus, eider and king eider. Again, a subsea spill with the size and properties of the spill from the Deepwater Horizon incident in the Mexican Gulf, which produced large subsurface plumes of dispersed oil, holds the potential also to impact the seabed communities in deep waters.

Impacts on fish

A surface spill is not expected to impact adult fish stocks in the open sea. Adult fish will avoid the oil, but very small oil concentrations may lead to tainting, rendering such oil-exposed fish impossible to sell. An oil spill in ice- 13 covered waters may pose a risk to populations of polar cod, an ecological key species. Any significant impacts on polar cod stocks may be transferred up in the food web (to other fish, seabirds and marine mammals). Another exception is a subsea spill, which could impact the fish both directly or through the food. Greenland halibut will also be exposed in both ways because they move up in the pelagic waters to feed. In coastal areas, fish stocks may be impacted from oil spills, and here especially stocks of capelin, lumpsucker and Arctic char are at risk. Capelin and lumpsucker can be exposed when they spawn in the tidal zone or in shallow waters right off the coast and Arctic char when they migrate to and from the river where they spawn and winter.

Impacts on seabirds

In the open sea, seabirds are usually more dispersed than in coastal habitats. However, in the assessment area there are some very concentrated and recurrent seabird occurrences for example in polynyas and in the shear zone. Post breeding concentrations of staging birds (such as thick-billed murres, Box

5) may also be vulnerable. Such concentrations of seabirds are extremely sensitive to oil spills and population effects may occur in case of oil in one of these habitats. The most important concentrations are the breeding thick-billed murres, the breeding little auks and migrating thick-billed murres (especially those on swimming migration). Migrating little auks may avoid the most oil polluted areas because they quickly move to the Canadian side of Baffin Bay. There are many other breeding concentrations of seabirds inside the assessment area, and some of the populations of less common species (such as Atlantic puffin) are very vulnerable to oil spills. Several nationally red-listed (threatened) species occur in the marine environment and populations of these will be exposed to potential oil spills in the assessment area. The little auk is not red-listed, but it is a national responsibility species in Greenland, because a vast majority of the world population is found within the assessment area. A major oil spill could seriously affect the viability of this population.

<u>Impacts on marine mammals</u>

Among the marine mammals, the polar bear is most sensitive to oiling, and several individuals may become fouled with oil in case of a large oil spill in the marginal ice zone. The impact of an oil spill may add to the general decrease expected for the polar bear population (therefore listed as threatened both nationally and internationally) as a consequence of reduced ice cover (global warming) and long-term over-exploitation. Whales, seals and walruses are also vulnerable to oil spills, particularly if they have to surface in oil slicks. Baleen whales may get their baleens smothered with oil and ingest oil. The extent to which marine mammals will actively avoid an oil slick and how harmful the oil will be to fouled individuals is not known, but whales have been observed moving directly into oil spills. Whales and seals are sensitive to inhaling oil vapours, and particularly narwhals, white whales, bowhead whales, walrus, ringed seal and bearded seal could be vulnerable during an oil spill in winter when the availability of open waters is limited by the sea ice. There is also a risk of indirect impacts on walrus and bearded seal populations through contamination of benthic fauna, especially at shallow (< 10-15 m) feeding grounds where oil may reach the seafloor.

<u>Impacts on fisheries and hunting</u>

An oil spill in the open sea will affect fisheries mainly via temporary closure in order to avoid contamination of catches. The duration of the closure will depend on the duration of the oil spill, weather conditions, etc. Even though the offshore fisheries for Greenland halibut within the assessment area are small (compared with other Greenland fisheries for this species), a closure zone will probably extend further south and cover a much larger area, including both

Greenland and Canadian fishing grounds. Oiled coastal areas would also be closed for fisheries for a period. There are examples of closure for many months due to oil spills, particularly if oil is caught in sediments or on beaches. The inshore fishery for Greenland halibut within the assessment area is important on a national scale, and a closure of these fishing areas will have significant economic consequences. Hunting in oil spill-impacted areas can be affected by closure zones and by changed distribution patterns of quarry species.

<u>Impacts on tourism</u>
The tourist industry in the assessment area will also experience negative effects from a large oil spill.

<u>Oil in ice</u>
Another especially vulnerable feature is ice-covered waters. Spilled oil will be contained between the ice floes and on the rough underside of the ice. In this case, oil may be transported in an almost un-weathered state over long ranges and may impact the environment, for example seabirds and marine mammals, far from the spill site when the ice melts. Oil may also be caught along ice edges and in the shear zone where sensitive species and ecosystem elements, such as primary production, zooplankton, polar cod, seabirds and marine mammals, aggregate. Particular concern has been expressed for polar cod stocks. This fish spawns in late winter, and the eggs accumulate just below the ice where spilled oil will also accumulate.

<u>Long-term impacts</u>
If an oil spill reaches the coasts of the Baffin Bay assessment area, long-term effects of residual oil buried in the beach sediments must be expected, as described for Prince William Sound."

Oil Spill Response in the Strategic Environmental Impact Assessment
The following section is copied from the new Strategic Environmental Impact Assessment for the Greenland Sea in Northeast Greenland. The report has not been published yet but has been in a public hearing in late 2020.[24]

"The best way to mitigate oil spills is by prevention and mitigation. To prevent and avoid oil spill accidents from for example exploration drilling, the highest health, safety and environment (HSE) standards and technical standards (BEP

[24] The report can be found at the following link:
https://naalakkersuisut.gl/~/media/Nanoq/Files/Hearings/2020/Strategisk%20miljoevurdering/Documents/SR375_SEIA.pdf

and BAT) must be applied together with strict regulations by the authorities, and careful planning of the entire process.

If a spill happens, there are three overall oil spill response technologies available for combatting oil spills in the marine environment: mechanical recovery, chemical dispersion and in situ burning. All three methods have their limitations in an arctic environment with drifting ice, such as in the assessment area. Recovery of oil from a sea surface covered with more or less ice is challenging and not a realistic option for a large spill in the assessment area. Ice edges can act as barriers containing oil in thicker layers suited for burning, a method which has proved very successful in experiments but is not yet developed and implemented in full operational scale. So far, no effective response methods have been developed for recovering or removing a large oil spill from waters with dynamic drift ice.

Oil spill response is also challenged by the dark winter period, the general weather conditions and the remoteness of the assessment area. It is therefore likely that very little - if any - oil can be recovered in case of an oil spill in the ice-covered parts of the assessment area.

The potential for biodegradation in Arctic areas is generally unknown, but several factors such as low temperatures, sea ice and low nutrient amounts may limit the ability of the microbes to degrade oil. The issue was therefore studied under the Strategic Environmental Study Program for Northeast Greenland.

The study showed that there is a biodegradation potential in the water column at the shelf break if the intrinsic microbial degraders can be activated, but the degradation will be hampered by nutrient limitation. The study also showed that the intrinsic potential for oil biodegradation in the water column and sediment on the shelf was very low, even when mineral nutrients were not a limiting factor.

The study clearly showed that, in general, in situ concentrations of mineral nutrients in the Greenland Sea during autumn are strongly limiting for biodegradation of oil. This most likely applies to the entire area and for most of the year. Natural degradation of oil will thus be very limited in the water column and is not a removal process to be counted on."

Annex 3 – Convergence path methodology

On behalf of the Danish Energy Agency for use in calculating its annual socioeconomic fuel prices, Ea Energy Analyses has developed a methodology that incorporates both short term market-based oil price estimates with long term forecasts from the IEA's World Energy Outlook. Referred to as a convergence pathway, the methodology provides for a gradual link between short/medium term market-based price projections (forward/futures' prices) and long-term IEA WEO price projections in a way that puts more weight on future/forward prices in the beginning of the convergence period, and shifting to exclusive reliance on the IEA WEO prices towards the end of the convergence period (see textbox for more detail).

Convergence pathway methodology

The 'convergence prices' in the context of this methodology are to be understood as short/medium-term price projections that are a combination of forward/future prices and the IEA WEO long-term prices for a given period of time. The convergence prices are produced as a weighted mean between IEA prices and IEA-scaled Future/Forward prices.

The World Energy Model (WEM), the main tool used in the development of the IEA WEO scenario projections, operates under the assumptions of long-term equilibrium, i.e., a state of the economy where the general price level is fully reflecting – and adjusted to - the existing set-up of the main price drivers and market factors (as opposed to short-term equilibrium or cyclicality where the price level might not be fully adjusted to the concurrent situation in the market due to different short-term market factors and distortions/fluctuations). As such, it is reasonable to apply the WEM in price projections in the medium/long-term based on fundamental supply and demand dynamics (subject to the realisation of the assumptions regarding these dynamics in the respective scenarios).

The figure below displays the convergence pathways for oil based on oil future/forward prices from Feb 14th, 2021, and oil prices in 2040 from the 2020 WEO's three primary scenarios. At the time of writing, oil futures prices were available until the year 2028, and these prices are indicated by the black dotted lines. As can be seen from the figure, at the current time those operating in oil futures markets are anticipating oil prices to fall (in real terms). The future oil prices from the WEO scenarios are marked with dots in the figure (2025 and 2040 for the Sustainable development and Delayed Response Scenarios, and 2025, 2030, 2035 and 2040 for the Stated Polices Scenario), and a simple linear interpolation was undertaken between data points.

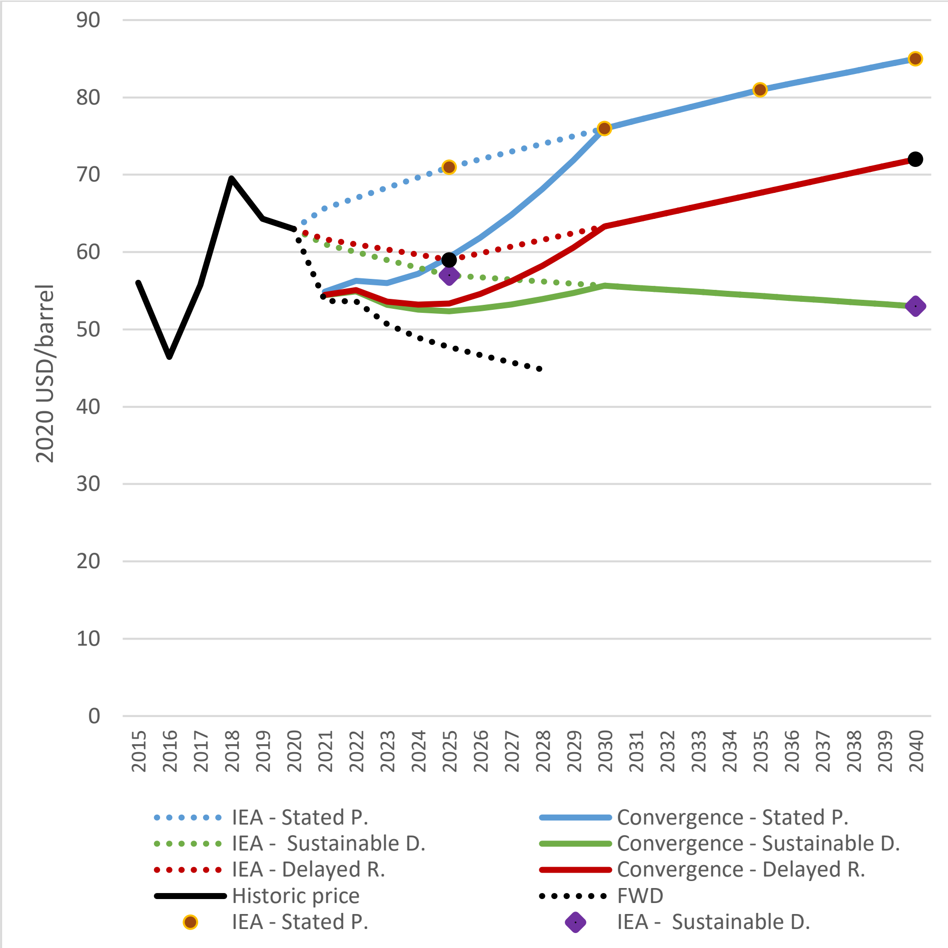

Figure 65: Convergence prices for oil based on oil futures prices from Feb 14th, 2021 and the 2020 WEO oil prices from the Stated Polices, Sustainable Development, and Delayed Response scenarios.

Annex 4 – Geographical presence of selected companies in Arctic regions

Gazprom

The majority state-owned Russian NC Gazprom has broad presence in the Russian Arctic, with both oil and gas producing fields. The map shows the oil and gas fields with largest production, accounting for at least 70% of its production by 2019.

Gazprom Group's fields in Russia with the largest production of natural gas and oil

	The largest fields by natural gas production		The largest fields by oil production
1	Zapolyarnoye	1	Priobskoye
2	Bovanenkovskoye	2	Novoportovskoye
3	Urengoyskoye	3	Prirazlomnoye
4	Yamburgskoye	4	Vyngapurovskoye
5	Yuzhno-Russkoye	5	Eastern block of the Orenburgskoye OGCF
6	Yamsoveiskoye	6	Sutorminskoye
7	Astrakhanskoye	7	Zapadno-Chatylkinskoye
8	Orenburgskoye	8	Vyngayakhinskoye

Note. The map shows Gazprom Group's hydrocarbon fields (excluding entities in which Gazprom has investments classified as joint operations) with combined production accounting for 70% or more of total natural gas and oil production in 2019.

Novatek

The Russian independent company Novatek owned 66 licences in the Russian Arctic as of 2019, with a strong presence in the Yamal-Nenets Autonomous region.

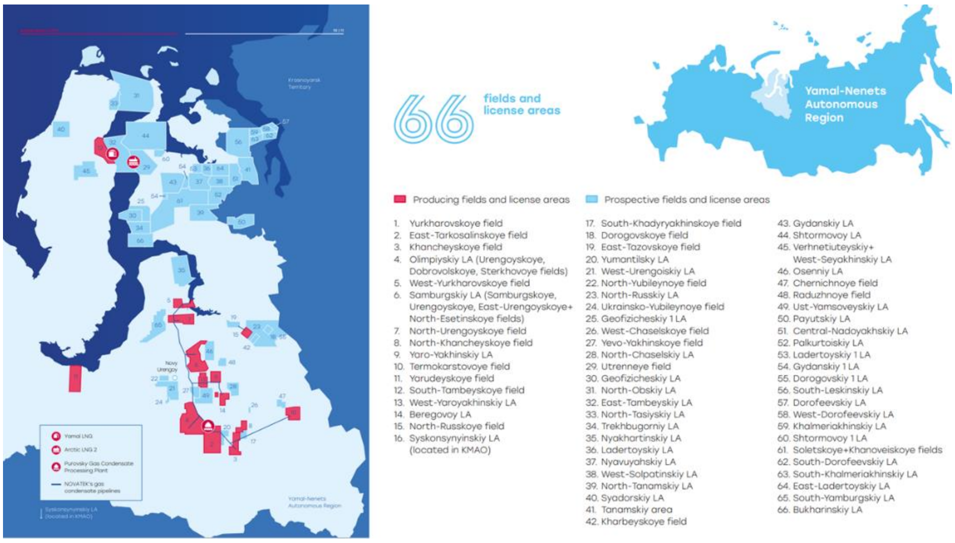

Figure 66: Novatek's licences in the Arctic (exploration and production). Source: Novatek (Novatek, 2020)

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