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UNCONVENTIONAL OIL & GAS ASSETS IN THE NET ZERO TRANSITION: HOW TO PRIORITISE THEIR PHASE-OUT WHILE MEETING ENERGY NEEDS

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EXECUTIVE SUMMARY

The net zero transition will require a major shift away from all hydrocarbons, and towards low and zero-carbon solutions, over the next 30 years. Though a range of 1.5°C pathways exist, from the IPCC, intergovernmental institutions and the private sector, there is consensus on the necessary phasedown of fossil fuels. These pathways align around an average decline in oil and natural gas demand of 80% and 70% by 2050, respectively, though there is a degree of spread within these projections.[1] A key implication from such declines is that, in a 1.5°C scenario, there is no requirement to develop new oil and gas reserves going forward. This conclusion initially emerged from the IEA Net Zero Emissions by 2050 (NZE) scenario, however it is consistent with other net zero pathways.[1]

To achieve net zero and keep the rise in the global average surface temperature to 1.5°C above the pre-industrial average, policy makers, oil and gas companies, and financial institutions – those seeking to reallocate their capital and manage risk accordingly – must determine how to effectively ramp down existing oil and gas production while ramping up decarbonised sources of energy. This should be based on break-even cost as well as other asset-specific factors, such as greenhouse gas emissions intensity and the likelihood of local environmental harm (which could translate into cost via carbon taxes and environmental regulation), as well as broader considerations around global and regional energy security.

One form of oil and gas – so-called "unconventional" assets – have met an increasing share of hydrocarbon supply over the last 20 years, and now represent roughly 34% of global oil and gas production.[2] Critics oppose the use of unconventionals because of environmental risks associated with their extraction[3], whilst supporters claim that unconventionals help to diversify supply and can provide other critical advantages such as regional energy security, shorter capital recovery cycles, and greater flexibility. There are different ways to define unconventional assets, but for this paper we include **extra-heavy oil and oil sands, Arctic oil and gas, ultra-deepwater oil and gas, and shale oil and gas extracted via hydraulic fracturing (a.k.a. "fracking")**.[4]

Unconventional oil and gas assets do not form a homogeneous group, and they differ significantly by (a) their break-even cost (including capex intensity, cycle duration, and operating costs), (b) their emissions intensity, (c) their capacity to cause local environmental harm, (d) the proportion of developed oil and gas reserves that they represent, and (e) their potential to improve energy security.

As an overall asset class, unconventionals are often (but not always) a lower quality supply source than conventionals, principally due to their increased environmental risks.[5] In a declining demand 1.5°C scenario, therefore, their prioritised phase out ahead of conventional assets can be viewed as preferable. In this paper we define a prioritised or accelerated phase out as one happening by 2035 at the latest, assuming it takes roughly 10-15 years to orchestrate a ramp down to zero. In

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[1] IISD (2022) *Navigating Energy Transitions: Mapping the Road to 1.5°C*. Scenarios considered in the analysis include: 26 selected 1.5°C IPCC scenarios, IEA NZE, BP Net Zero, the One Earth Climate Model (OECM), Navigant, the DNV Net Zero Pathway, and the IRENA WETO scenario. Scenarios align on an average oil demand decline of 80% by 2050, with projections ranging from 75%-98%. The average decline in natural gas demand is 70% by 2050. Ranges for natural gas declines are broader, with some scenarios clustering around a 50% decline by 2050 and others moving closer to 70%-80% and even 100% by 2050.

[2] In this respect, many argue these assets are now hardly "unconventional". However, for the purposes of this paper we use this term.

[3] See, for example: Urgewald/GOGEL (https://gogel.org/); WWF (https://www.arcticwwf.org/threats/oil-and-gas/); Greenpeace (https://www.greenpeace.org.uk/challenges/fracking/) [Accessed October 2022]

[4] Note that whilst we explicitly call out Arctic oil and gas for investigation within this paper, given its share of global production, we also recognise the importance of protecting other critical areas of environmental and social value, for example the Amazon Biome, UNESCO World Heritage Sites, and Ramsar Wetlands.

[5] We recognise that all conventional oil and gas exploration and production comes with environmental risks. Furthermore, we recognise that very poorly managed conventional assets can have major local environmental impacts. Key examples include poorly maintained assets in Russia, where even by government estimates the country is the worst oil spill polluter in the world, and assets in Nigeria which are often subject to theft, sabotage, and insurgent attacks. This study puts such cases of gross operational negligence or security risks to one side, instead focusing on, all else being equal, whether similarly managed unconventional assets display greater fundamental environmental risks than conventional assets due to either their location of operation (Arctic, ultra-deepwater) or their extraction practices (shale, oil sands and extra-heavy oil).

some cases, this can be done without disrupting global or regional energy markets, however in others it is likely that it cannot. Since there are wide variations between different unconventional types, the position is – as ever – nuanced.

Based on a detailed assessment of conventional and unconventional asset types, this paper draws the following conclusions:

Extra-heavy oil and oil sands generally have higher break-even costs, higher emissions intensities, and greater local environmental impacts than conventional assets. As a result, they face significant transition risks. They can be phased out in an accelerated manner without materially impacting global or regional security of supply.

- With existing production asset break-even prices of $33/bbl for extra-heavy oil and $39/bbl for oil sands these asset types can be more expensive, given their higher energy requirements, than conventional oils, which tend to be in the range of $8-36/bbl. However, we note that some of the most competitive extra-heavy oil and oil sands assets operate between $20-30/bbl and so could remain active throughout the 2030s and beyond.
- These asset types are strong candidates for an accelerated phase out[6] as global oil demand declines due to their high emissions intensity (30% higher on average than other oil types) and high risk of local environmental harm. Their upstream carbon intensity and high abatement costs make them particularly vulnerable to carbon taxes.
- In a 1.5°C scenario there is a global oversupply of oil based on existing developed reserves, with an estimated 9 Mb/d surplus by 2030.[7] Collectively, oil sands and extra-heavy oil represent 5% of global developed reserves and 7% of annual oil production. An accelerated phase out of these asset types could see production fall by approximately 3 Mb/d by 2030. Accordingly, these asset types can be phased out without materially impacting global security of supply.
- Regionally, oil sands production is concentrated in Canada, and extra-heavy oil is concentrated mostly in Venezuela and Mexico. We conclude that an accelerated phase out does not materially impact energy security for these markets, in a 1.5°C scenario, as other domestic resources can supply up to 84-93% of local oil demand by 2030-2035.

Arctic oil and gas assets have mixed cost-competitiveness depending on location and asset type. They do not typically display higher emissions intensities versus conventional assets but can have significant negative environmental impacts. Arctic oil can be phased out without materially impacting global or regional security of supply, however Arctic gas cannot.

- Due to a challenging operational environment Arctic production can be expensive, with US and Russian Arctic oil assets displaying break-even prices up to $50-70/bbl. However, after significant efficiency investments Norway claims its next-gen Arctic assets are now highly cost-competitive, with break-even prices as low as $25-35/bbl. Arctic gas, concentrated principally in Russia, is also cost-competitive, with an average break-even price of $1.7/MBtu. Conventional gas break-even prices typically range between $0.9-2.8/MBtu.
- In general Arctic assets do not display higher emissions intensities versus conventional assets. However, they should still be prioritised for early phase out owing to the risk of accidents and oil spills and the significant impact these can have on local ecosystems. These factors are reinforced by the need to reduce black carbon deposits from oil and gas flaring which accelerate Arctic ice-melt.

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[6] In this paper we define a prioritised, or accelerated phase out as the production of these asset types reaching zero by 2035, assuming it takes broadly 10-15 years to manage such a decline.

[7] This definition includes both developed (i.e., producing) oil and gas reserves and those under-development and due to come online in the near-term, having received final investment decision (FID) on or before 31st December 2021.

- Arctic oil makes up 3% of global developed oil reserves and 3% of annual oil production, and so can be phased out with materially impacting security of supply. Arctic gas reserves are more significant, however, representing 20% of global developed gas reserves and 14% of annual gas production. These cannot be phased out in an accelerated manner unless replaced with new sources of conventional gas, with associated lead times and infrastructure lock-in/stranded asset risks.
- At a regional level, Arctic oil and gas production is concentrated in Russia, which represents over 90% of global Arctic supply. Arctic oil makes up 20% of total Russian oil output and can be substituted with significant local conventional reserves, the annual production of which equates to almost three times domestic oil demand, enabling an accelerated phase out. Arctic gas, however, makes up 80% of Russian gas production and roughly 50-60% of this is required to meet domestic needs, meaning a full phase out would have local energy security implications, though a partial phase out might be possible. We disregard much of the potential impact on European energy supply given the hydrocarbon decoupling between these regions following the invasion of Ukraine.[8]

Ultra-deepwater oil and gas assets are cost-competitive and do not typically display higher emissions intensities versus conventional assets. However, they can have significant environmental risks. These asset types can be phased out at a global level, but there may be energy security complexities at a regional level.

- Ultra-deepwater assets (i.e., those which have a water depth greater than 1,500m)[9] are increasingly cost-competitive, with break-even prices of $24/bbl for oil and $1.8/MBtu for gas.[10]
- Like Arctic assets, they do not have higher emissions intensities, on average, than conventional oil and gas, but they can have significant environmental consequences in cases of accidents and oil spills, albeit these are low likelihood events (e.g., Deepwater Horizon).
- Ultra-deepwater assets make up just 3% of worldwide developed oil and gas reserves and annual production, and so can in theory be phased out at a global level.
- However, there may be some regional security of supply considerations which would instead favour a partial phase out. For example, over 90% of global ultra-deepwater oil is in the US Gulf of Mexico and offshore Brazil, though whilst it only represents 5% of US oil supply, it makes up a much larger portion – 30% – of Brazilian domestic supply.
- For ultra-deepwater gas, there may also be some regional complexities. For example, the Tamar/Leviathan fields in the Mediterranean are now deemed by some to be strategically important for Israeli and broader European gas supplies, on the heels of reduced flows coming from Russia.

Shale oil and gas assets are increasingly cost-competitive and do not display higher emissions intensities, on average, than conventional assets. They have greater local environmental risks, but these are deemed to be less sizeable than for other unconventional asset types. Shale gas can't be phased out without impacting global and regional security of supply. The case is less compelling for shale oil, which can be phased out globally, though there could be some regional energy security complexities.

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[8] We note that whilst pipeline imports of Russian Arctic gas have reduced significantly since the invasion of Ukraine, Europe is still purchasing Russian Arctic LNG, and indeed import volumes of LNG have gone up year on year. However, these LNG imports are an order of magnitude smaller than Russian pipeline imports at 10-15 Bcm per annum versus 100 Bcm+ for pipeline gas. Accordingly, we still see a much-reduced role for Russian Arctic gas in European markets going forward. See Politico (2022) *The Russian gas habit Europe can't quit: LNG*.

[9] Ultra-deepwater thresholds have evolved over time as technological improvements have enabled operators to push to even greater offshore depths. There is therefore a degree of variation is how it is defined, with some sources such as the IEA claiming 2,000m+ (see 2018 World Offshore Energy Outlook) and others such as the EIA, NGOs, and data providers such as Rystad, WoodMac and IHS opting for 1,500m+. For the purposes of the analysis in this white paper we adopt a 1,500m+ definition.

[10] Note that these average break-even prices include both deepwater and ultra-deepwater assets.

- The costs of shale assets have come down significantly in recent years with average break-even prices for existing production assets now reaching $22/bbl and $1.4/Mbtu for oil and gas, respectively.
- Shale assets are not typically more carbon intensive than conventional assets (particularly when methane emissions are well-managed). We see valid local environmental concerns about hydraulic fracturing, or "fracking", which could justify an accelerated phase out. However, we view these as generally more manageable, with strong regulation and robust oversight, than environmental risks linked to other asset types such as oil sands and Arctic assets.
- Shale gas represents 16% of global developed gas reserves and 27% of annual production, so it cannot be phased out globally without replacement sources of new conventional gas. At a regional level, shale gas represents 85% of US domestic supply meaning an accelerated phase out would have significant implications for local energy security, noting also that the EU and other blocks are likely to be more dependent on exported LNG from shale resources for the short-to-medium term.
- In general, the case for continued production of shale gas is stronger than for shale oil given logistical considerations and a longer plateau for gas demand. Shale oil represents 8% of global developed oil reserves and 14% of annual production, and much of this can be phased out in an accelerated manner without materially impacting global security of supply, given anticipated levels of oversupply by 2030. Oil is traded globally, so regional security of supply is less of an issue than for gas. Nonetheless, we do note that shale oil currently represents 65% of US oil production, and a similar level of domestic demand. An accelerated phase out, therefore, could raise local energy security risks. However, as US domestic demand declines in line with the requirements of a net zero pathway, the case for phasing down US shale oil production, especially those reserves which are not closely linked to shale gas production, would correspondingly strengthen.[11]

In summary, while there are variations in break-even cost and carbon intensity across asset types, the main argument for the accelerated phase out of unconventionals is due to environmental concerns (with the associated risk of increased regulation/costs to address these). We believe extra-heavy oil and oil sands, the most carbon intensive and environmentally impactful asset type, can be phased out without materially impacting global and regional energy security. The story for other unconventionals, however, is more complex. Arctic oil can be phased out, but Arctic gas is still needed at a global level during the energy transition. Ultra-deepwater oil and gas can be phased out globally, but there may be regional energy security considerations which would instead favour a partial phase out. Shale gas cannot be phased out without impacting global and regional security of supply. Shale oil can be phased out globally, but there may be some regional energy security complexities.

Where accelerated phase outs are considered feasible, local social and economic issues will need to be carefully managed. For example, whilst the oil and gas sector generates around 5% of Canada's overall GDP, it represents over 20% of the province of Alberta's GDP, where oil sands production is concentrated.[12]

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[11] There is a technical challenge around deploying an accelerated phase out for oil and not gas, as the two products are often found in reservoirs together, but there are approaches to managing this. One solution is to use a production threshold. For example, consider shale oil and gas. We may label a shale asset as "gas" if >50% of combined production (in boe) is gas, and vice versa for oil. This will always result in some oil being produced but it will enable a degree of segmentation. An analysis of shale oil and gas fields (using RMI OCI+ data) shows that a 50% production threshold enables the capturing of fields currently producing 88% of shale gas and only 18% of shale oil as a by-product. If the gas production threshold is decreased to 20%, then assets providing 97% of gas supply and 54% of oil supply are captured.

[12] Canada National Statistics (2021) *The oil and gas sector in Canada: A year after the start of the pandemic.*

Our integrated conclusions are summarised in the image below:

Resource	Type	Cost of Production (vs. Conventionals)	GHG Emissions Impact (vs. Conventionals)	Environmental Impact (vs. Conventionals)	Required Due to Global Supply Needs	Potential Regional Energy Supply Concerns	Accelerated Phase Out Conclusion
Extra-heavy Oil & Oil Sands	**Oil**	Mid-High	Consistently Higher	High (Rank 4)	No	No	**Yes**
Arctic Oil	**Oil**	Mixed (Low/High)	Not Consistently Higher *(Driven by Operational Practices)*	High (Rank 3)	No	No	**Yes**
Ultra-Deepwater Oil	**Oil**	Competitive		High (Rank 2)	No	Partially	**Partially**
Shale Oil	**Oil**	Competitive		Mid-High (Rank 1)	No	Yes	**Partially**
Arctic Gas	**Gas**	Competitive		High (Rank 3)	Partially	Yes	**Partially**
Ultra-Deepwater Gas	**Gas**	Competitive		High (Rank 2)	No	Partially	**Partially**
Shale Gas	**Gas**	Competitive		Mid-High (Rank 1)	Partially	Yes	**No**

NOTES: Environmental impact vs. conventional assets shows a ranking from 1-4 in order of impact, with 4 being the most impactful and 1 being the least impactful. Based on our qualitative impact assessment, ranking unconventional asset types from greatest to least environmental impact has oil sands and extra-heavy oil as number one, followed by Arctic oil and gas, ultra-deepwater oil and gas, and then shale oil and gas.

When interpreting these conclusions, it is important to remember that a 1.5°C pathway does not require, at a global level, any new oil and gas fields to be developed.[13] Both conventional and unconventional oil and gas asset classes will phase down over time given declining demand. When discussing an "accelerated" phase down or phase out, therefore, we are referring to which specific asset classes should be prioritised for early phase down, and potentially a full phase out, ahead of the broader sector declines. Additionally, whilst for this analysis we have chosen to focus specifically on unconventionals as an asset class, we encourage the use of our assessment framework when evaluating all oil and gas investments to minimise negative externalities and transition risks across the board.

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[13] We note that the term 'field', whilst well defined for conventional assets, is somewhat nebulous for shale oil and gas developments which can cover an expanse of land only partially covered by extraction wells. Continuous development of new wells is often needed given high decline rates. A degree of continued expansion within existing areas is recognised and consistent with 1.5°C pathways.

We recognise there are both valid geographical concentration and climate equity concerns associated with the managed decline of hydrocarbon supply over the course of the energy transition. Both questions, of course, involve considerations which go well beyond this paper, which focuses on the optimal approach to an accelerated phase-down of unconventional hydrocarbon assets. With regard to geographic concentration concerns, the paper has explicitly incorporated local energy security factors in its phase-down pathway design. We also note the risk that if the world does not reduce hydrocarbon demand rapidly, then both energy and climate security will be severely compromised. The first-best route to solving both security challenges remains greater investment in clean energy supply, accelerated electrification of energy demand and greater focus on energy efficiency. With regard to climate equity, the question of whether countries in the Global South, in particular Sub-Saharan Africa, should develop new hydrocarbon reserves, is a critical energy transition topic, but one that falls outside the scope of this paper. That said, the development of any field (whether conventional but especially unconventional) needs to be challenged (in all geographies) given the risk that this expands supply into markets which, in 5-10 years, should be in long-term decline if we are to stay on/near a 1.5°C pathway.

Despite recognising the potential need for near-term flexibility in the energy transition, we stress this should not be used as an excuse to abandon the pursuit of a 1.5°C world or delay the move away from hydrocarbons. Bridging the gap to a 1.5°C pathway requires an immediate and rapid scale up in the deployment of clean energy and other low-carbon solutions. To deliver the energy transition, global investment into renewable energy, low-carbon fuels, energy efficiency, electric vehicle charging infrastructure, and grid and battery infrastructure needs to increase from $1.2tn today to $4.2tn by 2030.[14] Such green investments must be a global priority with particular attention made to financing mechanisms which can enable the Global South to participate fully in the opportunity presented by the clean energy revolution.

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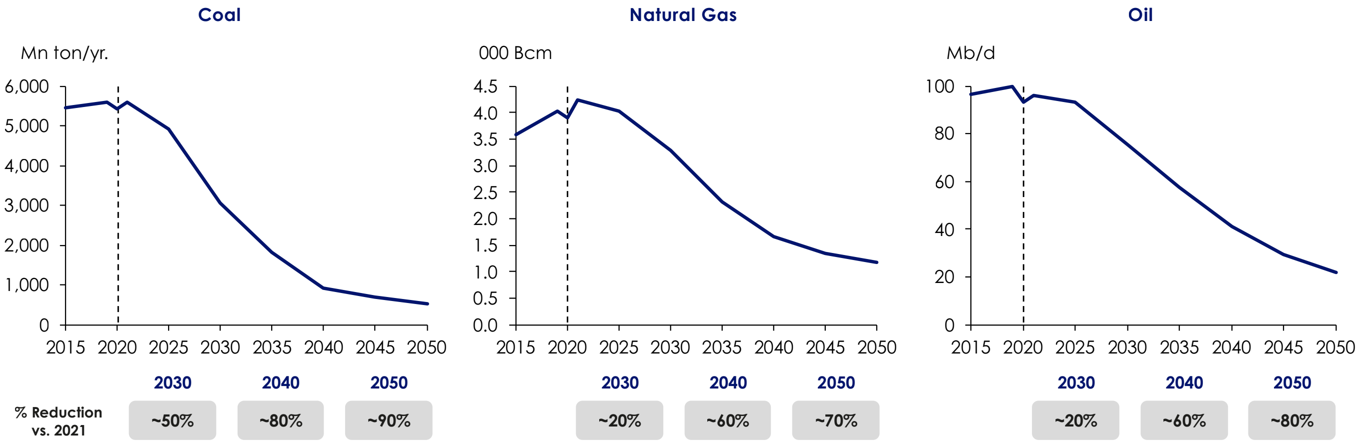
[14] IEA (2022) *World Energy Outlook.*

INTRODUCTION

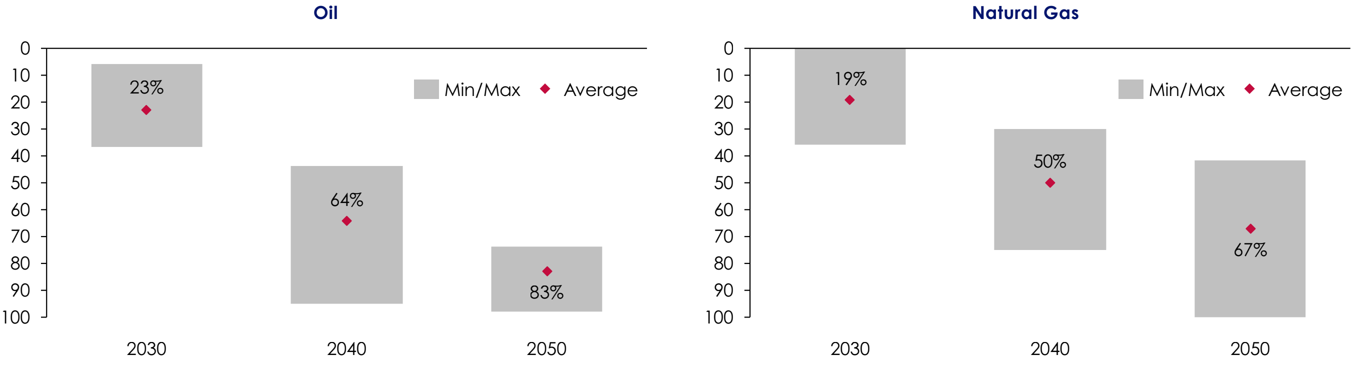
The global pathway to net zero requires a deep and rapid move away from fossil fuels alongside accelerated investment into a clean energy system. Though a range of possible net zero end states exist, every modelled IPCC pathway sees steep declines in hydrocarbon demand going forward.[15] A recent study from the International Institute for Sustainable Development (IISD) compared 26 IPCC 1.5°C scenarios as well as a host of scenarios from intergovernmental and private sector organisations, such as the International Energy Agency (IEA) and the International Renewable Energy Agency (IRENA), and found a strong degree of consensus on hydrocarbon phase down. Collectively, these scenarios point to the urgent need for oil and gas demand to decline by 80% and 70%, respectively, between now and 2050 (see Exhibit 1).[16]

Exhibit 1: *Fossil fuel demand outlook to 2050 under IEA Net Zero and a range of other 1.5°C-aligned scenarios*

PANEL A: Global production of fossil fuels (IEA NZE Scenario)



PANEL B: Oil and gas projected demand declines in a range of 1.5°C-aligned net zero scenarios



NOTES: Panel A shows the projected production declines for coal, natural gas, and oil out to 2050 in the IEA NZE scenario. Panel B compares the projected declines for oil and natural gas across a range of broadly 1.5°C-aligned scenarios for 2030, 2040, and 2050. The boxes show the min and max decline rates for the scenario group each year whilst the red points show the group average. The following scenarios are included: (i) the median of 26 IPCC 1.5°C scenarios (as selected by the IISD – see sources), (ii) the IEA NZE Scenario, (iii) the UTS OECM Scenario, (iv) the IRENA WETO 1.5°C Pathway, (v) the Navigant Pathway to Net Zero, (vi) the DNV Pathway to Net Zero, and (vii) the BP Net Zero Scenario.

SOURCES: BP (2021) *Statistical Review of World Energy*; IEA (2021) *Net Zero by 2050*; IEA (2022) *World Energy Outlook;* IISD (2022) *Navigating Energy Transitions: Mapping the Road to 1.5°C.*

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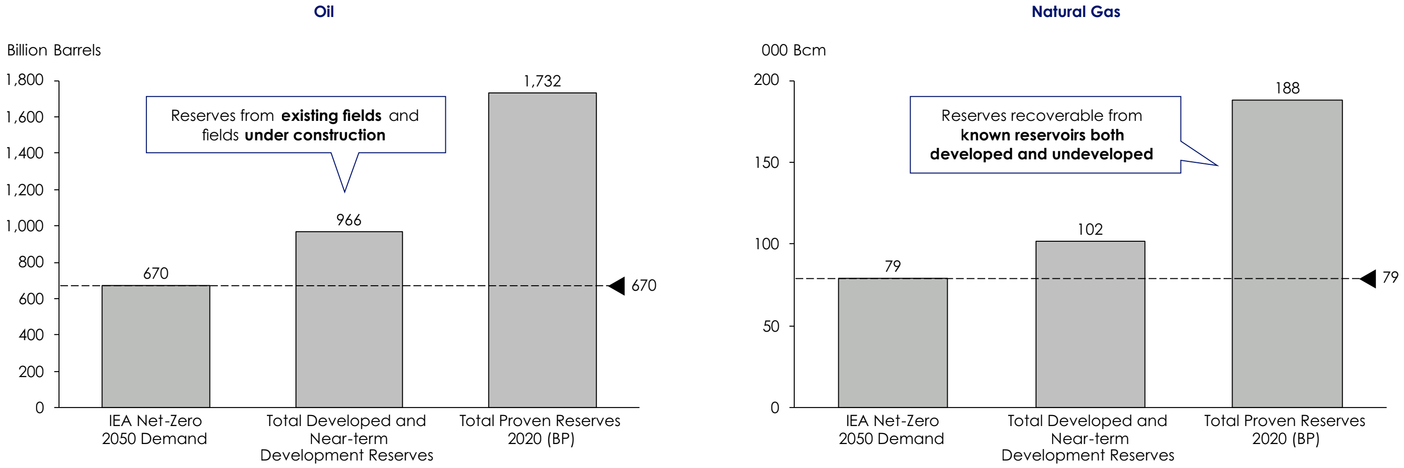
[15] The Sixth Assessment Report from the Intergovernmental Panel on Climate Change (IPCC).

[16] IISD (2022) *Navigating Energy Transitions: Mapping the Road to 1.5°C*. Scenarios considered in the analysis include: 26 selected 1.5°C IPCC scenarios, IEA NZE, BP Net Zero, the One Earth Climate Model (OECM), Navigant, the DNV Net Zero Pathway, and the IRENA WETO scenario.

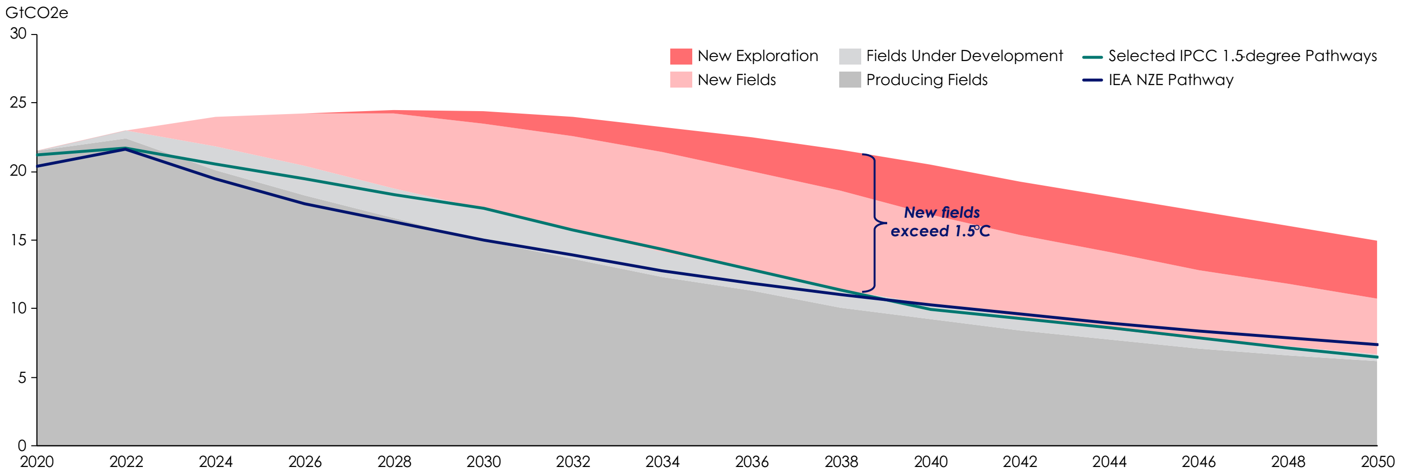
The IEA is widely acknowledged as a leader in energy system analysis and its Net Zero Emissions by 2050 (IEA NZE) scenario is one of the most credible published climate pathways. On this basis we have selected it to anchor the analysis in this paper. The IEA NZE is broadly aligned with the IISD scenario group average, with oil and gas production down by 20% from 2021 levels in 2030, and by 80% and 70% respectively by 2050 (see Exhibit 1).[17]

Exhibit 2: *Oil and gas demand outlook to 2050 in IEA Net Zero and selected 1.5°C IPCC pathways compared with developed reserves and new versus existing fields*

PANEL A: Cumulative oil and gas demand to 2050 in IEA NZE vs. existing developed and proven reserves



PANEL B: Projected oil and gas production based on selected IPCC and IEA 1.5°C pathways vs. existing and new fields (Source: IISD)



NOTES: Panel A shows IEA NZE cumulative demand to 2050 versus existing developed and proven reserves. Total proven reserves of oil and gas are generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions (i.e., already discovered fields). Reserves include gas condensate and natural gas liquids (NGLs) as well as crude oil. Total developed reserves taken from Trout et al. (2022), as of January 2018, and total near-term development reserves taken from GOGEL (2022) based on a review of global oil and gas expansion project commitments as of 2021. Total proven reserves from BP Statistical Review of World Energy include developed reserves, reserves under development, and undeveloped but discovered reserves. Panel B shows global oil and gas production based on selected IPCC pathways and IEA NZE versus existing and new fields – it is recreated from IISD (2022) Navigating Energy Transitions: Mapping the Road to 1.5°C.

SOURCES: BP (2021) *Statistical Review of World Energy*; IEA (2021) *Net Zero by 2050*; IEA (2022) *World Energy Outlook*; Trout et al. (2022) – *Existing fossil fuel extraction would warm the world beyond 1.5°C*; Global Oil and Gas Exit List, GOGEL (2022); IISD (2022) *Navigating Energy Transitions: Mapping the Road to 1.5°C*; Systemiq analysis (2022).

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[17] Over the period to 2030 this oil and gas demand reduction is principally driven by (i) reduced use of fossil fuels for electricity production, (ii) the electrification of transport (EVs) and buildings (heat pumps), (iii) improvements in energy efficiency, and (iv) behavioural changes through the use of targeted policies to reduce energy needs, particularly in the developed world, for example to encourage the use of more efficient vehicles, the greater use of public and low-carbon transport, greater working from home, energy-saving measures with respect to building heating, and reduced demand for aviation through frequent flyer levies and reduced business travel.

One of the more important conclusions from the IEA NZE is that demand for oil and gas between now and 2050 can be met by existing fields[18] and, as a result, further expansion of oil and gas supply is inconsistent with limiting the rise in global average surface temperature to 1.5°C above the pre-industrial average. This conclusion is supported by other 1.5°C-aligned scenarios, as well as our own analysis (Exhibit 2).

The decline in demand for fossil fuels in net zero scenarios carries profound implications for hydrocarbon producers and raises the question of where, and how, supply will be phased down. Market forces are likely to push out highest cost supply first. However, there are other important considerations to be factored into decision-making by policy makers, financial institutions, and energy companies; in particular, the emissions intensity of resource production, refining, transportation, and consumption[19], local environmental impacts, asset flexibility and payback, and regional energy security.

"Unconventional" oil and gas resources have played an increasing role in global hydrocarbon supply over the last 20 years. Conventional oil and gas resources are defined as having relatively easy-to-reach hydrocarbons, where the natural pressure from the well is all that is required for said hydrocarbons to flow. There is no universally agreed upon definition of "unconventional" oil and gas resources, however they can broadly be considered as those that are technically more challenging to extract than conventional oil and gas. This can be because they are in hard-to-reach locations or because they are difficult to recover due to geological constraints. For example, extra-heavy oil, oil sands and shale resources require the use of enhanced extraction techniques, such as surface mining, in-situ extraction[20], and hydraulic fracturing, given the nature of the underlying rock formations. Ultra-deepwater offshore and Arctic resources, on the other hand, can utilise conventional extraction processes but must couple these with advanced drilling and other technologies given the challenging operating conditions of their respective environments. For the purposes of this report, we define "unconventionals" as extra-heavy oil and oil sands, resources in the Arctic, resources in ultra-deepwater, and shale oil and gas (see Exhibit 3).[21] These asset types account for most unconventional production today.[22]

Growth in unconventional hydrocarbon supply over the last 20 years reflects advances in relevant technologies and declining costs. In 2020, unconventionals accounted for around 34% of global hydrocarbon production, and they represent around 50% of current reserves under development.[22] As their presence has grown, unconventionals have become an increasingly important part of global, and particularly Western[23], supply, however they have also attracted criticism from NGOs owing to perceived environmental issues associated with their production.

In this paper we explore the role of unconventionals in the energy transition. We first consider how they might be ramped down in a declining demand scenario based on production costs. We then consider the case for accelerated phase outs based on climate and environmental impacts versus conventional assets. Finally, we consider the impact of accelerated phase outs on global and regional energy security.

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[18] Defined as hydrocarbon projects currently producing or currently under development and expected to come online in the coming years where final investment decision (FID) was taken on or before 31st December 2021.

[19] Oil and gas emissions intensity covers upstream, midstream, and downstream. Upstream emissions come from hydrocarbon production and processing, midstream emissions come from refining processes and storage, and downstream emissions come from transportation and consumption.

[20] In-situ extraction techniques for extra-heavy oil and oil sands resources can include Steam Assisted Gravity Drainage (SAGD), Cyclic Steam Simulation (CSS), Toe to Heel Air Injection (THAI), and Vapour Extraction Process (VAPEX).

[21] This definition excludes biofuels, gas hydrates, oil shales (kerogen) and liquid synthetic derivatives of coal and gas.

[22] Global Oil and Gas Exit List, GOGEL (2022); an Urgewald project, and Systemiq analysis (2022).

[23] For example, most developed oil sands and shale oil and gas reserves sit in North America.

Exhibit 3: *Conventional and unconventional hydrocarbon definitions*

	Resource	**Estimated % Share of O&G Production**			**Main Production Location(s)**	**Characteristics**
		Oil	**Gas**	**O&G**		
Unconventionals	Extra-heavy Oil & Oil Sands	7%	--	**4%**	Canada, Mexico, Venezuela	Crude oil grades with API gravity of 10.0 or below. Oil Sands (also called natural bitumen) is deemed a sub-set of Extra-heavy Oil
	Arctic Oil & Gas	3%	14%	**7%**	Arctic (Russia, Norway, US)	Multiple definitions exist. The main two include hydrocarbons recovered from within the Arctic Circle (66°33'N), or within the AMAP region[24]
	Ultra-Deepwater Oil & Gas	3%	3%	**3%**	**Oil:** US, Brazil **Gas**: US, Brazil, Mozambique, Israel, Egypt	Multiple definitions exist, but usually defined as hydrocarbons recovered from offshore reservoirs in which the water depth exceeds 1,500m[25]
	Shale Oil & Gas	14%	27%	**19%**	US, Canada	Hydrocarbons recovered from tight rock formations via hydraulic fracturing (includes tight oil and gas)[26]
Conventionals	Conventional Oil & Gas	73%	56%	**66%**	Global	Any hydrocarbons recovered via a well drilled into a geological formation in which the reservoir and fluid characteristics permit the oil & gas to readily flow to the wellbore

SOURCES: Global Oil and Gas Exit List, GOGEL (2022); American Petroleum Institute; Arctic Monitoring and Assessment Programme (AMAP); Systemiq analysis (2022).

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[24] The AMAP (Arctic Monitoring and Assessment Programme) region is a much more expansive geographical definition than the Arctic Circle, covering a greater proportion of northern Canada, Alaska, and Russia (see comparison here: https://www.amap.no/about/geographical-coverage). However, in terms of developed Arctic hydrocarbon assets currently in production the two definitions are broadly comparable – most large assets are concentrated in northern Russia near and within the Arctic Circle (see here: https://reclaimfinance.org/site/arctic-map/). [Accessed October 2022]. For the purposes of the analysis in this white paper we adopt the Arctic Circle definition.

[25] Ultra-deepwater thresholds have evolved over time as technological improvements have enabled operators to push to even greater offshore depths. There is therefore a degree of variation is how it is defined, with some sources such as the IEA claiming 2,000m+ (see 2018 World Offshore Energy Outlook) and others such as the EIA, NGOs, and data providers such as Rystad, WoodMac and IHS opting for 1,500m+. For the purposes of the analysis in this white paper we adopt a 1,500m+ definition.

[26] It is noted that some conventional oil and gas fields deploy hydraulic fracturing techniques to enhance hydrocarbon recovery (particularly at aging fields). Our analysis still treats these fields as conventional assets.

ANALYSIS 1: BREAK-EVEN COSTS

In Exhibit 4 we show high-level information on the average and range of break-even prices for different operational conventional and unconventional asset types. This information helps to indicate which asset types might first become uneconomic in a declining demand scenario. It should be noted that these prices do not include the externalities considered elsewhere in this paper (e.g., carbon emissions/tax).

Exhibit 4: *Break-even prices for existing oil and natural gas production assets*

PANEL A: Break-even oil prices

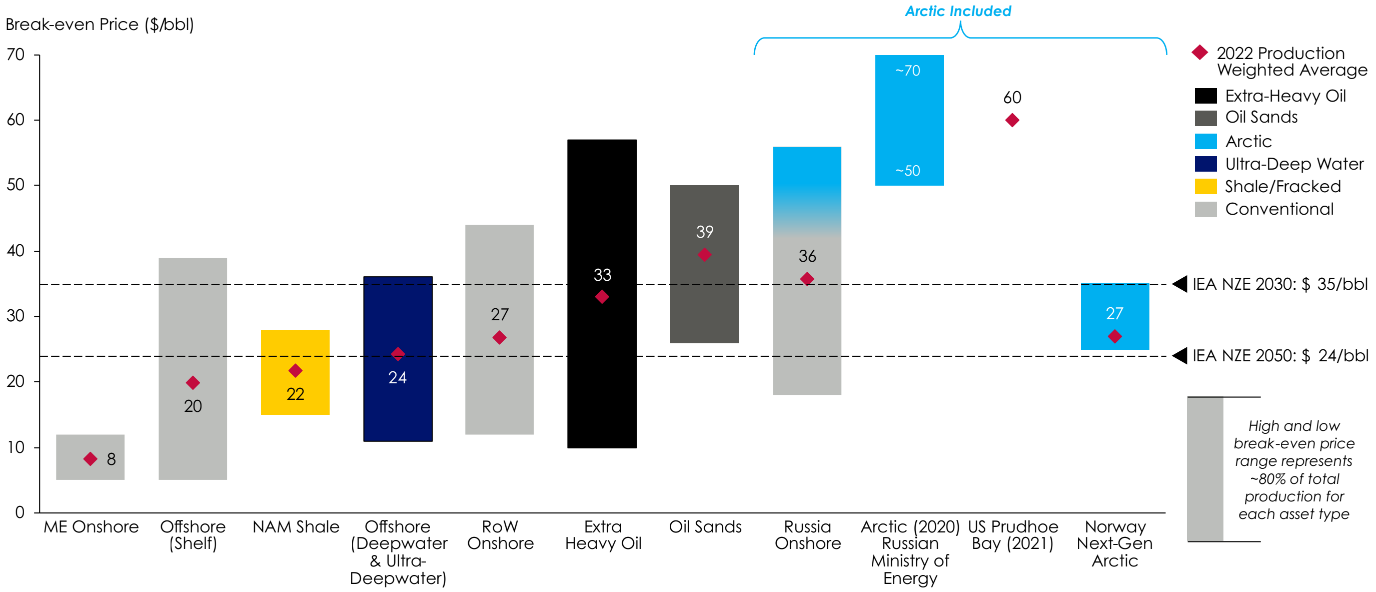
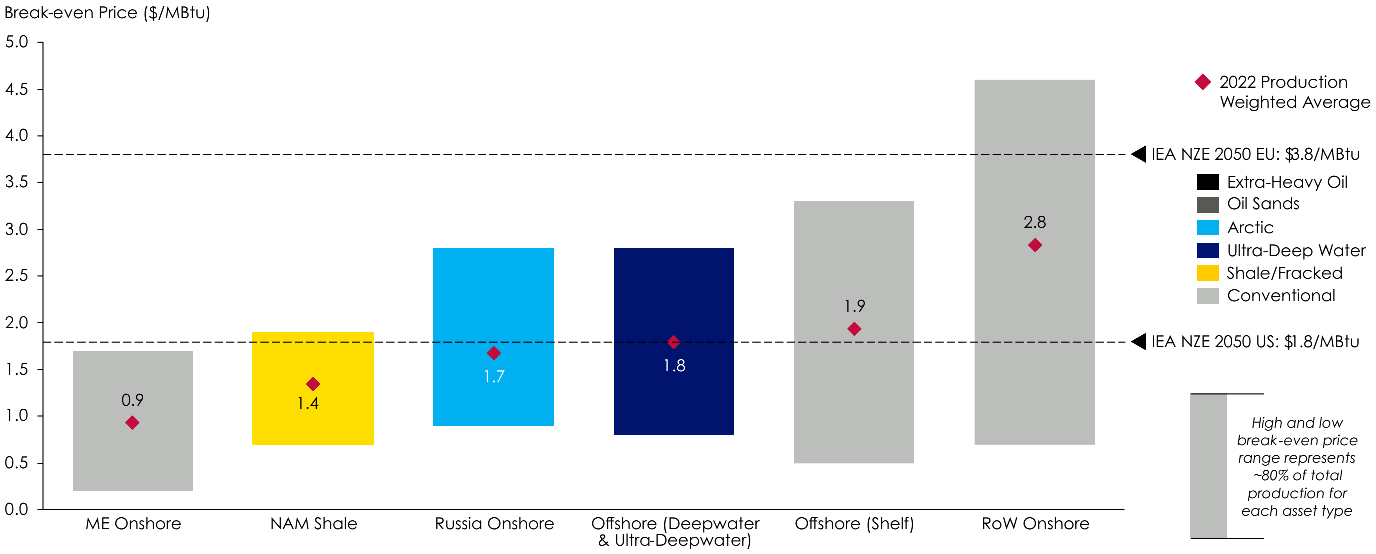


Exhibit 4b: Break-even natural gas prices for existing production assets

PANEL A: Break-even natural gas prices



NOTES: Break-even oil prices for existing assets, based on 2022 Rystad data except for additional Arctic assets, where stated. Russian onshore break-even prices will include, towards the top end, the break-even prices for Arctic assets, however these are not split out. In addition, Arctic break-even prices from the Russian Ministry of Energy, US Prudhoe Bay, and for Norway Next-Gen projects are shown. ME = Middle East. NAM = North America. RoW = Rest of World.

SOURCES: Rystad (2022) with Systemiq analysis; OilPrice.com (2017) *Norway Doubles Down on Arctic Oil*; Chanysheva A et al. (2021) *The Future of Russian Arctic Oil and Gas Projects: Problems of Assessing the Prospects*; IEA (2022) *World Energy Outlook*; BP Prudhoe Bay Royalty Trust (2021).

After seeing sustained cost reductions over the last decade, existing deepwater/ultra-deepwater oil and shale oil assets are cost-competitive with many conventional assets, with an average break-even price of $22-24/bbl. All these assets currently operate below the projected IEA NZE oil price in 2030 of $35/bbl, and it is likely that a significant proportion will also be in the money in 2050 when the IEA NZE oil price is $24/bbl. This means that shale oil and ultra-deepwater oil could feature throughout the energy transition, based on economics alone. The same is true for shale and deepwater/ultra-deepwater gas assets, which have average break-even prices between $1.4-1.8/MBtu, in line with or well below IEA NZE gas price projections for the US and Europe of $1.8/MBtu and $3.8/Mbtu in 2050, respectively.

Oil sands and extra-heavy oil assets are generally more expensive, operating at an average break-even price range of $33-39/bbl today, though they are still cost-competitive with many conventional Russian assets (average break-even price of $36/bbl). This higher price makes it more likely that oil sands and extra-heavy oil will be phased out earlier in the transition, though some of the most competitive assets could still be around through to the 2030s and beyond.

The story for Arctic assets is mixed. Given a technically challenging operational environment, Arctic production has historically been deemed higher cost than many other asset types. Arctic oil production is mostly concentrated in Russia, which has some of the highest break-even prices globally. Figures from the Russian Energy Ministry give a break-even development price range of between $50-70/bbl. In the US, the break-even price for Prudhoe Bay, one of the largest Arctic oil assets in North America, is $60/bbl. Norway, however, claims that after significant efficiency investments and tax incentives, the break-even price of its next-generation Arctic assets is now as low as $25-35/bbl, down from $70/bbl in 2013.[27]

Although Russian Arctic oil might be relatively expensive to extract, Russian Arctic gas is much more competitive. Making up around 80% of total Russian gas production, it has an average break-even price of approximately $1.7/MBtu. This is well in the money relative to natural gas prices under IEA NZE which fall to $1.8/MBtu in the US, and $3.8/MBtu in Europe by 2050. This suggests some Arctic assets are likely to be cost competitive throughout the 2030s and 2040s.

In summary, based solely on a consideration of break-even costs in a declining demand scenario it is likely that cost-competitive unconventionals, such as ultra-deepwater and shale, will continue to play a role in the 2030s and beyond. Extra-heavy oil and oil sands represent some of the most expensive asset types, which would imply an earlier phase out. For Arctic the story is mixed: expensive US and Russian oil assets could be phased out early in the energy transition, whereas some highly cost-competitive oil assets in Norway and gas assets in Russia could continue to feature over the long-term.

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[27] OilPrice.com (2017) *Norway Doubles Down on Arctic Oil.*

ANALYSIS 2: CARBON INTENSITY

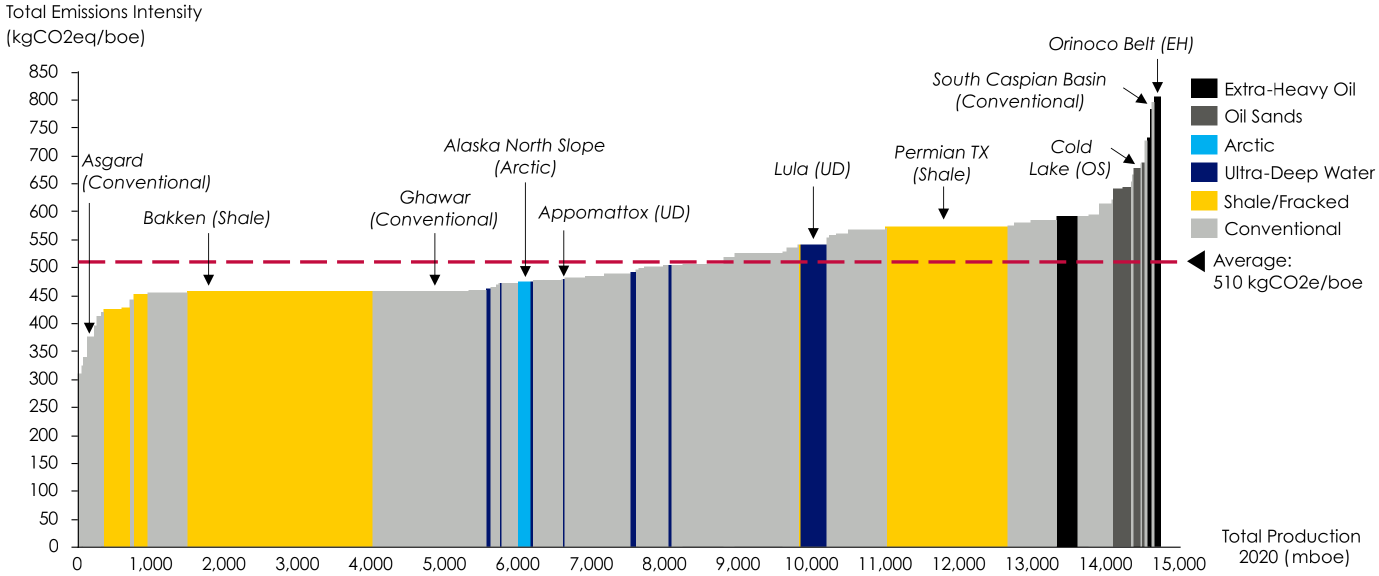
The climate impact of different hydrocarbon resources can be determined by examining their lifecycle greenhouse gas (GHG) emissions intensities. These emissions intensities can vary considerably depending on how the oil and gas is extracted, processed, refined, transported, and used. In Exhibit 5, we show the modelled lifecycle emissions intensities (covering upstream, midstream, and downstream[28]) for 135 oil and gas fields around the world, separated across conventional and unconventional resource types, as defined in Exhibit 3. This analysis uses data from the Rocky Mountain Institute (RMI) OCI+ database, which covers approximately 50% of global oil and gas production as of 2020.[29]

Extra-heavy oil and oil sands display some of the highest emissions intensities of all asset types, up to four times higher than the lowest emission oil fields and 30% more carbon intensive than the oil field average. This is principally because oil sands and extra-heavy oil require more energy to be extracted and refined (via deep conversion) than other oil types, and because they have high-carbon by-products (further detail later in this section).

No other unconventional assets have a clearly higher climate impact than conventional resources, and some are even less carbon intensive. For example, the Bakken shale field in North America has a lower lifecycle emissions intensity than other conventional oil plays, operating 11% below the oil field average. The Tamar (Israel ultra-deepwater), Marcellus (US shale), and Snøhvit (Norwegian Arctic) fields also have lower emissions intensities than many conventional gas plays, ranging from 15%-45% below the gas field average.

Exhibit 5: *GHG emissions intensity by oil and natural gas field for conventional and unconventional resource types 2020 (50% of global production)*

PANEL A: Oil Fields



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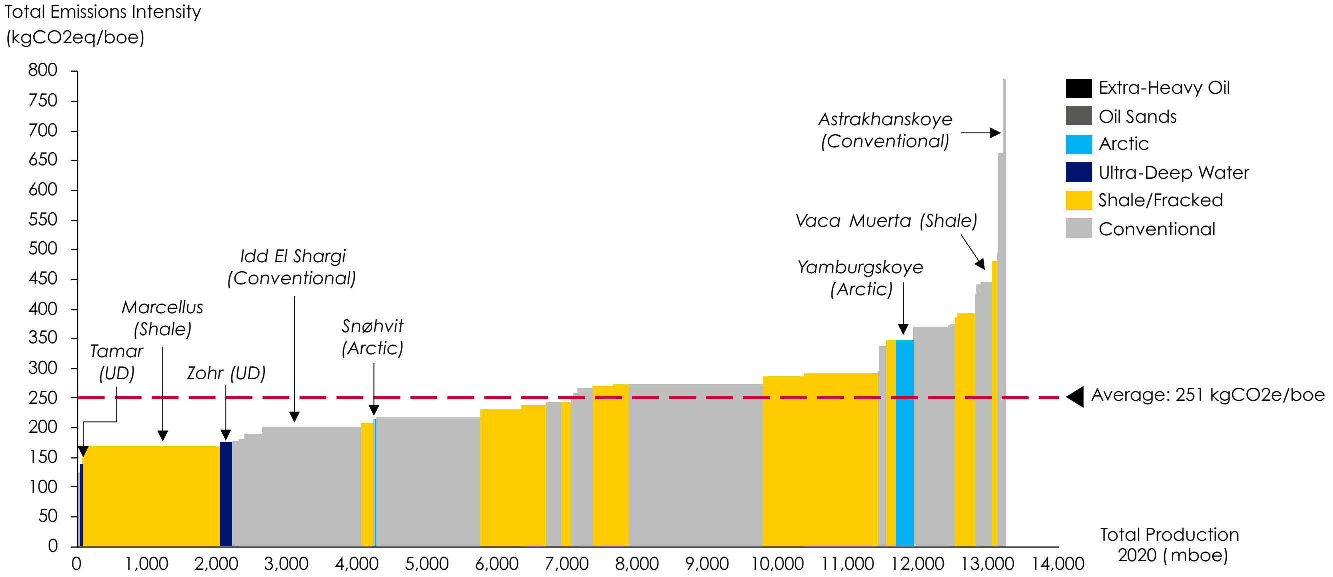
[28] Upstream emissions come from hydrocarbon production and processing, midstream emissions come from refining processes and storage, and downstream emissions come from transportation and consumption.

[29] The dataset is not yet complete and around 30% of the assets are from North America, which increases the potential for skew. Furthermore, there is a limited sample size for some asset types, such as Arctic and ultra-deepwater, where there were only 3 and 7 fields respectively to analyse. Recognising these limitations, the database still provides the most extensive publicly available coverage for oil and gas assets worldwide, covering both small and large fields across 41 countries, and using comprehensive, bottom-up and peer reviewed emissions models. We believe it is therefore the most robust foundation available, using public data, on which to conduct our analysis.

PANEL B: Natural Gas Fields



NOTES: Data shown for 50% of the world's oil and gas production in 2020 including condensates. Emissions intensity calculated using Global Warming Potential (GWP) over 100-year period for total lifecycle emissions (upstream, midstream & downstream). Average refers to production weighted mean across all fields. Arctic defined here as the 'Arctic Circle', latitude of 66.33° north of the Equator. UD = Ultra-deepwater; EH = Extra-heavy oil; OS = Oil sands.

SOURCES: RMI (July 2022) – Oil Climate Index + Gas Model v.1.0, 2022; Systemiq analysis (2022).

The analysis in Exhibit 5 shows emissions intensities using a 100-year GWP conversion factor for non-CO_2 gases, as per IPCC guidance. The Appendix shows the same charts using a 20-year GWP conversion factor, which emphasizes the impact of other GHG emissions, particularly methane. Under these conditions the story remains the same, with extra-heavy oil and oil sands assets clustering at the top end of the carbon intensity spectrum and no clear trend emerging for the remaining asset types.

Emissions mitigation strategies exist for extra-heavy oil and oil sands; however, they are challenging to implement. These resources currently require considerably more heat, steam, and hydrogen for their extraction, transportation, and conversion into high-value products such as gasoline or diesel.[30] In addition, they yield higher shares of petcoke in their refining process, which is a low-value but high-carbon by-product used in deep conversion coking refineries and to produce energy in countries with lax environmental standards. Example mitigation measures include installing solar steam to replace existing steam injection; installing upstream carbon capture and storage (CCS); deploying green hydrogen in the refining process; and preventing downstream petcoke combustion.[31] Successfully implementing these measures could be challenging and expensive, particularly as many rely on emerging technologies. For example, solar steam installations can have high upfront costs (up to $12/bbl), although savings from reduced natural gas requirements can provide payback over the long-term.[32] Carbon capture technologies have been deployed with some success to date in oil and gas fields but are still in their early stages and can add significant cost. Using operational examples, applying CCS could increase oil sands production costs by $3-9/bbl (or 8-23%).[33] Key oil sands firms Suncor and Cenovus Energy have publicly stated that getting oil sands operations to net zero by 2050 would collectively require $60bn, and that they would need major government financial support to achieve this.[34]

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[30] D. Gordon et al (2014) *Know Your Oil – Creating a Global Oil-Climate Index*, Carnegie Endowment for International Peace.

[31] D. Gordon et al. (2022) *Know Your Oil and Gas - Generating Climate Intelligence to Cut Petroleum Industry Emissions*, RMI.

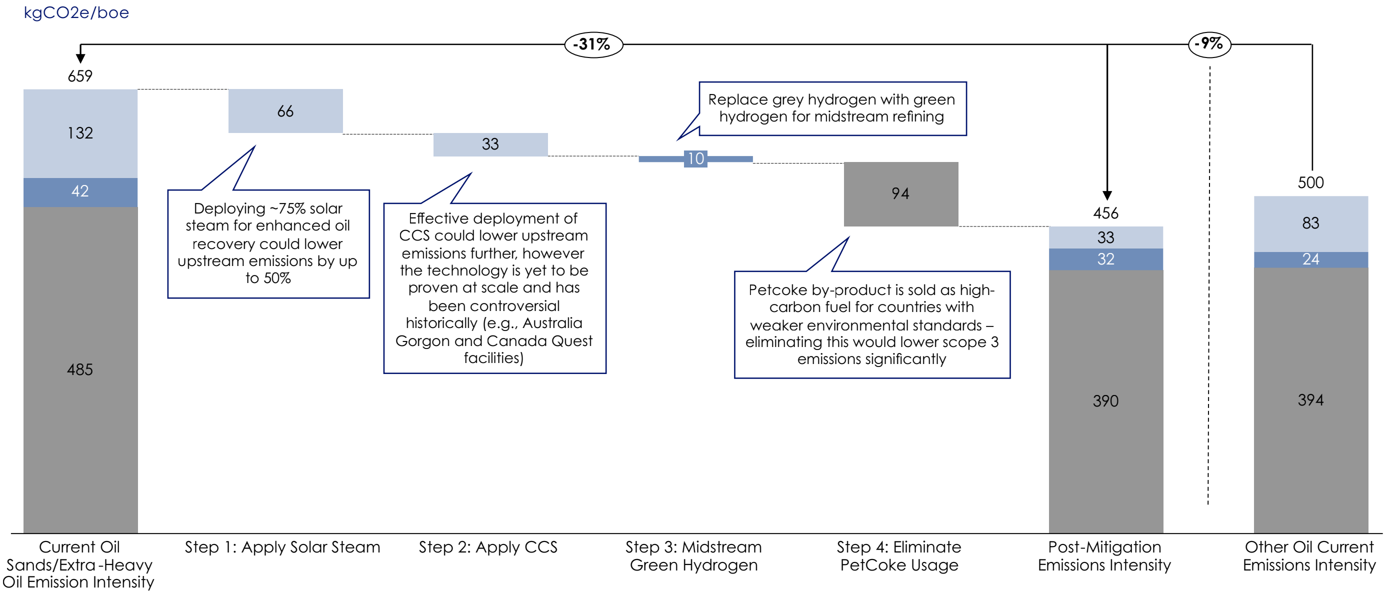
[32] Janzen R et al. (2020) *Greenhouse gas emission abatement potential and associated costs of integrating renewable and low carbon energy technologies into the Canadian oil sands.*

[33] For example, the Quest oil sands CCS project in Canada is estimated to have a lifetime cost of $1.3 billion dollars to capture 30% of the facility's carbon emissions. Current operational performance is $80/tCO2e. Assuming a cost range of $50-100/tCO2e, and if the technology is used to capture 30-50% of upstream emissions from Canadian oil sands assets, then CCS could add $3-9/bbl to production costs going forward. Sources: Canadian Fuels Association (2019) *Shell's Quest CCS facility stores over a million tonnes of CO2 annually*; Oxford Energy (2021) *The Role of CCUS in Accelerating Canada's Transition to Net-Zero*; Systemiq analysis based on RMI OCI+ (2022).

[34] OilPrice.com (2021) *Canada's Oil Sands Need $60 Billion To Achieve Net-Zero Emissions.*

Even if all mitigation measures were successfully implemented, the average emissions intensity of extra-heavy oil and oil sands fields would only be reduced to a level just below the current weighted average of other oil asset types, according to our calculations based on RMI OCI+ data (see Exhibit 6). Since other oil field operators will implement their own climate mitigation measures over the same period, many of which will be cheaper or even profitable to deploy, such as methane capture and utilisation, it's likely that extra-heavy oil and oil sands will continue to be the highest emitting asset types going forward. Such assets are therefore particularly at risk of becoming uncompetitive under carbon tax regimes. For example, if a \$75/tCO_2e carbon tax were applied to upstream production emissions across the assets covered by this analysis, then it would increase production weighted break-even costs by \$10/bbl for oil sands and extra-heavy oil assets, and by \$6 for all other oil asset types.

Exhibit 6: *GHG emissions mitigation strategies for extra-heavy oil and oil sands fields*



NOTES: Analysis based on RMI OCI+ data and emissions mitigation levers set out in the 2022 RMI Know Your Oil and Gas Report.

SOURCES: RMI, Oil Climate Index plus Gas Model v.1.0, 2022; D. Gordon et al. (2022) *Know Your Oil and Gas – Generating Climate Intelligence to Cut Petroleum Industry Emissions*, Rocky Mountain Institute; Systemiq Analysis (2022).

Other than extra-heavy oil and oil sands, the climate impact of oil and gas fields is generally determined by how well a resource is managed, particularly with respect to methane emissions, rather than by resource type. Poorly managed conventional resources often have higher emissions intensities than well managed unconventional resources. One of the most important factors affecting total emissions intensity is the level of upstream methane venting, leakage and flaring that occurs on the oil or gas field. For example, the South Caspian Basin conventional oil field in Turkmenistan has a high gas flaring rate and is estimated to have an upstream emissions intensity of 552 kgCO_2e/boe using a 20-year GWP. This is around nine times higher than the Appomattox ultra-deepwater offshore oil field in the US, which has a low flaring rate.[35] On average, methane accounts for over one-half of upstream operational emissions, and the share is much higher for poorly managed fields, like the South Caspian Basin where it is 77% (see Exhibit 7). In some fields, methane also drives a similar share in life-cycle emissions due to gas leakage during transmission and distribution.[36]

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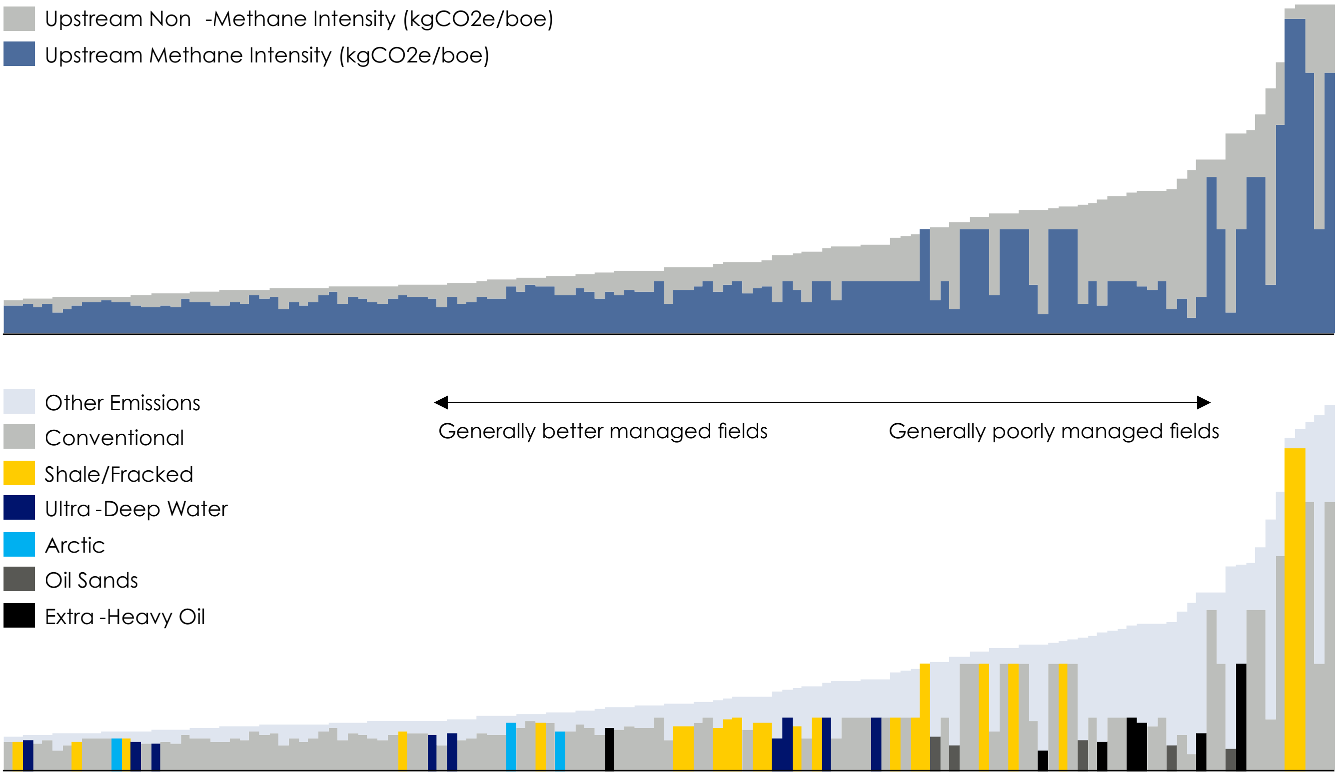
[35] Rocky Mountain Institute RMI OCI+ Database (2022).

[36] For example, the operations involved in transporting gas via pipelines and to and from LNG terminals increase the risks of methane leakage. It also requires significant amounts of energy for this gas to be liquified and regasified, meaning LNG increases the climate footprint of total shipping emissions by over 30%. See: D. Gordon et al. (2022) *Know Your Oil and Gas - Generating Climate Intelligence to Cut Petroleum Industry Emissions*, Rocky Mountain Institute.

Exhibit 7: *Upstream emissions intensity for oil and gas resources*



NOTES: Exhibit shows the major role methane plays in driving upstream emissions. Each vertical line on the graph represents a single oil or gas resource, for a total of 135 modelled results. The top chart shows the split between methane and non-methane upstream emissions (using a 20-year GWP conversion). The bottom chart shows the same data but details which asset type, whether conventional or unconventional, is being shown. In general, poorly managed assets will have high methane emissions and better managed assets will have lower methane emissions. Extra-heavy oil and oil sands assets have structurally lower methane emissions due to their resource type – most emissions from these assets come from other areas such as the energy intensive extraction process.

SOURCES : D. Gordon et al. (2022) *Know Your Oil and Gas – Generating Climate Intelligence to Cut Petroleum Industry Emissions*, Rocky Mountain Institute; RMI, Oil Climate Index plus Gas Model v.1.0, 2022; Systemiq analysis (2022).

In summary, beyond extra-heavy oil and oil sands, we do not see a clear climate argument for the accelerated phase out of other types of unconventional assets. We do however emphasise the importance of robust field management, in particular the minimisation of methane venting, leakage, and flaring, which can in many cases be done at marginal or even negative abatement cost, given commercial opportunities.[37]

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[37] IEA (2021) *Curtailing Methane Emissions from Fossil Fuel Operations.*

ANALYSIS 3: ENVIRONMENTAL RISKS

In addition to global climate related risks arising from CO_2, methane, and other GHG emissions, unconventional oil and gas extraction can also present a host of local environmental risks. These may arise from routine operations or from unplanned developments and accidents. The following section describes the environmental risks arising from each of the four unconventional resource types under discussion and presents a qualitative assessment of their probability, impact, and overall severity.

We recognise that all conventional oil and gas exploration and production comes with environmental risks, such as oil spills, and soil, water, and air pollution. Furthermore, we recognise that very poorly managed conventional assets can have major local environmental impacts, even if they are not operating in particularly sensitive or hazardous environments or deploying invasive extraction practices. Key examples include poorly maintained assets in Russia, where even by government estimates the country is the worst oil spill polluter in the world, and assets in Nigeria which are often subject to theft, sabotage, and insurgent attacks.[38] This study puts such cases of gross operational negligence or security risks to one side, instead focusing on, all else being equal, whether similarly managed unconventional assets display greater fundamental environmental risks versus conventional assets due to either their location of operation (Arctic, ultra-deepwater) or their extraction practices (shale, oil sands).

In short, all types of unconventional oil and gas assets often pose greater local environmental risks than conventional assets, which may, in itself, be a credible argument for an accelerated phase out. Ranking unconventional asset types from greatest to least environmental impact has oil sands and extra-heavy oil as number one, followed by Arctic oil and gas, ultra-deepwater oil and gas, and shale oil and gas. The key elements of this analysis are summarized in Exhibit 8.

Exhibit 8: *Local environmental risks arising from unconventional oil and gas production*

	Extra-heavy Oil/Oil Sands	**Arctic**		**Ultra-Deepwater**		**Shale & Hydraulic Fracturing**
KEY RISKS	• Extraction requires **high energy, water, and chemicals** use due to low permeability of rocks • Resources mainly located in **biodiverse** environments (e.g., Canadian Boreal Forest) • Production often requires **clearing forests/draining wetlands, resource intensive mining** and on-site processing & creates **toxic by-products** • Significant risk of **toxic chemical leakage from tailings ponds** into surrounding environment	• Fragile ecosystem means oil spills can have **major environmental consequences** • Response to oil spills typically slower and **clean-up can be difficult due to remoteness** of area • Risk of accidents could increase with global warming as much existing O&G infrastructure built on **thawing permafrost** • **Black carbon air pollution** caused by gas flaring is accelerating global warming in the region		• **Routine operations present multiple low-level threats** to the local marine environment, including from discharges of waste and wastewater, and impacts from anchors and pipelines • Water depths and challenging operating conditions **increase the likelihood and severity of spills and blowouts**, which can cause **major environmental damage**		• Extraction of shale oil/gas resources via hydraulic fracturing typically requires **higher energy, water, and chemicals** use due to low permeability of rocks • Changes in land use can lead to local habitat degradation • Extraction process **creates waste liquid** ("produced water") which can contain toxic substances • However, strict environmental controls can mitigate some of these risks
EXAMPLE FIELDS	*Athabasca Oil Sands (Canada), Orinoco Belt (Venezuela)*	*Goliat Field (Norway), Yamburgskoye Field (Russia), Prudhoe Bay (USA)*		*Deepwater Horizon (US GOM), Tamar Gas Field (Israel), Tupi / Lula Offshore (Brazil)*		*Permian, Marcellus, Bakken, Eagle Ford (USA), Montney BC (Canada)*
EVENT TYPE	**Routine**	**Routine**	**Unplanned**	**Routine**	**Unplanned**	**Routine**
PROBABILITY	HIGH	MID HIGH	MID	HIGH	MID LOW	HIGH
IMPACT	HIGH	MID HIGH	HIGH	LOW	HIGH	MID
OVERALL ASSESSMENT	HIGH	MID HIGH	HIGH	LOW	HIGH	MID HIGH

SOURCES: Systemiq analysis (2022).

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[38] The Russian government reported 500,000 tons of oil spills in 2014, however some environmentalists estimate the figure could be closer to 5,000,000 tons p.a. (or 1% of the country's oil production). To put this into perspective, the US, which at the time produced a similar amount of oil as Russia, reported oil spills of 15,000 tons per annum. Russia's spills, therefore, equate to 30-300+ times the level of spills in the US, per unit of production. For further information see The Seattle Times (2014) *Constant Oil Spills Devastate Russia*; and ISS (2022) *Endless Oil Spills Blacken Ogoniland's Prospects*.

EXTRA-HEAVY OIL AND OIL SANDS

Extra-heavy oil and oil sands are crude oil grades with very low API gravity, as defined by the American Petroleum Institute.[39] They are thick and highly viscous materials that cannot easily flow from production wells under normal reservoir conditions. This means it takes more energy and water to process them into end-products and they contain more impurities, such as sulphur and heavy metals.[40] There are three primary methods of extraction: strip/surface mining; in-situ extraction using water, steam, or chemical solvents; and a process called Cold Heavy Oil Production with Sand, or CHOPS.

Strip/surface mining for oil sands results in major disruption to the local landscape, including the conversion of existing boreal forests into mine sites and supporting infrastructure. A 2014 study by the World Resources Institute (WRI) estimated that between 2002 and 2012 forest loss in Alberta, which is caused by oil sands development as well as logging and other industrial activity, amounted to 5.5% of total land area, exceeding forest loss rates in Brazil over the same period (which were 4.3% of total land area). In the 475,000-hectare region where oil sands development is most concentrated forest loss reached 20% over the same period.[41] Such development also results in land fragmentation, leading to species migration corridors being lost, affecting species diversity and viability.[42]

Extra-heavy oil and oil sands extraction processes also lead to the production of contaminated wastewater, known as produced water, which is stored in above ground tailing ponds. These tailing ponds can be significant in size. A report in 2021 from the Alberta Energy Regulator stated that tailings ponds in the Canadian Athabasca oil sands region alone increased by 90 million cubic meters in 2020, bringing the total to 1.36 billion cubic metres of fluid tailings.[43] Wastewater in tailing ponds contains a variety of chemicals deemed harmful to aquatic organisms, birds, and other local wildlife.[44] The risk of leakage into nearby rivers or groundwater is well documented and recent studies have shown elevated levels of pollutants in the Canadian Athabasca river system.[45] Tailing ponds also appear to have negative effects on local air quality, with implications for human health, on the back of fugitive emissions of volatile organic compounds and other pollutants to the atmosphere.[46]

In summary, we see strong environmental rationale for the accelerated phase out of extra-heavy oil and oil sands.

ARCTIC EXPLORATION AND PRODUCTION

Low temperatures, strong winds, changing ice patterns and seasonal darkness make oil and gas activity in the Arctic especially technically challenging, which increases the risk of accidents and local pollution.[47] Moreover, the fragile nature of the ecosystem means even routine operations and supporting infrastructure can have serious consequences relating to waste and water discharge, disturbances to local biodiversity and indigenous communities, and air pollution.

The potential impact of oil spills in the Arctic – especially offshore – is significant. The remoteness, lack of infrastructure, and inhospitable conditions in the region means accident response and clean-

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[39] The American Petroleum Institute's "API gravity" is a standard to express the specific weight of oils, computed as (141.5/sg) - 131.5, where sg is the specific gravity of the oil at 60 degrees Fahrenheit. The lower the specific gravity value, the higher the API gravity will be.

[40] American Geosciences Institute (2018) *Heavy Oil.*

[41] World Resources Institute, WRI (2014) *Tar Sands Threaten World's Largest Boreal Forest.*

[42] Bayne et al. (2005) *Modelling and field-testing of ovenbird responses to boreal forest dissection by energy sector development at multiple spatial scales.*

[43] Alberta Energy Regulator (2021) *State of Fluid Tailings Management for Mineable Oil Sands, 2020.*

[44] Royal Society of Canada (2010) *Environmental and Health Impacts of Canada's Oil Sands Industry.*

[45] Commission for Environmental Cooperation (2020) *Alberta Tailings Ponds II. Factual Record regarding Submission.*

[46] Moussa et al. (2021) *Fugitive Emissions of Volatile Organic Compounds from a Tailings Pond in the Oil Sands Region of Alberta.*

[47] The Oxford Institute for Energy Studies (2014) *The Prospects and Challenges for Arctic Oil Development.*

up operations are challenging.[48] Nor are conditions in the Arctic favourable to oil biodegradation common in other regions, leaving toxic materials in the environment for prolonged periods.[49] Even small oil spills on Arctic land can kill tundra plants through smothering, chemical toxicity, and temperature changes.[50] Moreover, oil pollution on soil increases the absorption of incoming solar radiation and may increase the depth of the seasonally thawed layer, leading to the development of thermokarst, or marsh-like terrain, further degrading the area, releasing trapped GHG emissions and destabilising local infrastructure (which again can increase the risk of accidents).[51] In the absence of rapid restoration and clean up, impacts to plants and other local life can last decades, causing large scale, long-lasting ecological damage.[52] In 2020, an oil spill in Norilsk, Arctic Russia, caused by the collapse of destabilised infrastructure on thawing permafrost, resulted in 21,000 tonnes of diesel contaminating an area of 350 km^2. It was deemed one of the worst Arctic environmental disasters to have occurred in the country. The clean-up cost has been estimated at $1.5bn over 5 to 10 years.[53]

Finally, black carbon air pollution caused by incomplete combustion of natural gas during flaring is accelerating global warming in the region. Researchers have concluded that flaring emissions from Arctic oil and gas assets, particularly in Russia, contribute more to regional black carbon surface concentration than any other emission category, accounting for 42% on average.[54] Black carbon pollution is significant because it reduces the local albedo effect, meaning less sunlight is reflected off Arctic surfaces, accelerating global warming.

In summary, we see strong environmental rationale for the accelerated phase out of Arctic oil and gas.

ULTRA-DEEPWATER

Offshore "ultra-deepwater" oil and gas exploration and production is usually defined as those assets where the depth of water from the seabed to the sea level is beyond 1,500m. Routine ultra-deepwater operations present multiple threats to the local marine environment, including from discharges of drilling and material waste, contaminated wastewater, and physical impacts from anchors and pipelines. However, although none of these are trivial, neither are they considered significantly more impactful than risks associated with conventional offshore assets.[55]

The main environmental risks associated with ultra-deepwater operations come from non-routine incidents such as oil spills. Offshore operations have the potential to result in accidental releases of oil and gas into the ocean, with the likelihood and severity of a spill increasing with the depth of the operation.[56] Although these events are not considered part of routine operation they still occur with relatively high frequency. For example, on the US outer continental shelf between 1971 and 2010, there were 23 large offshore spills of more than 1,000 barrels of oil on average every 21 months.[57] Furthermore, the environmental effects of ultra-deepwater oil spills tend to be longer lasting than those onshore or in shallow waters since cold deepwater ecosystems' lifecycles typically move at a slower pace. Consequently, the effects of a spill can last years or even decades.[58] The greatest risk comes from uncontrolled release of hydrocarbons from the reservoir itself, otherwise known as a blowout.[59] Examples of blowouts include the IXTOC-1 well (Mexico, 1979), Ekofisk (Norway,

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[48] Aune et al. (2018) *Seasonal ecology in ice-covered Arctic seas - Considerations for spill response decision making.*

[49] Aarhus University (2018) *Oil-eating microbes are challenged in the Arctic.*

[50] Morten Tryland (2022) *Arctic One Health: Challenges for Northern Animals and People.*

[51] Various sources in *Arctic One Health: Challenges for Northern Animals and People* (2022).

[52] Morten Tryland (2022) *Arctic One Health: Challenges for Northern Animals and People.*

[53] BBC (2021) *Norilsk Nickel: Mining firm pays record $2bn fine over Arctic oil spill.*

[54] Stohl et al. (2013) *Black Carbon in the Arctic: the underestimated role of gas flaring and residential combustion emissions.*

[55] Cordes et al. (2016) *Environmental Impacts of the Deep-Water Oil and Gas Industry: A Review to Guide Management Strategies.*

[56] Muehlenbachs et al. (2013) *The impact of water depth on safety and environmental performance in offshore oil and gas production.*

[57] Anderson et al. (2012) *Oil Spill Occurrence Rates for Offshore Spills.*

[58] Chanton et al. (2014) *Using natural abundance radiocarbon to trace the flux of petrocarbon to the seafloor following the deepwater horizon oil spill.*

[59] Johansen et al. (2003) *Deep Spill – field study of a simulated oil and gas blowout in deep water.*

1980), and Enchova (Brazil, 1984) but the most recent and widely known example is the Deepwater Horizon disaster that occurred in the US Gulf of Mexico in 2010, where a blowout resulted in an oil slick covering 40,000km^2, the severe environmental consequences of which are numerous and well documented.[60] The Deepwater Horizon rig typically operated in waters approximately 1,250m deep, but the accident occurred when drilling a 1,500m exploration well at the Macondo site.[61]

In summary, we see strong environmental rationale for the accelerated phase out of Ultra-deepwater.

SHALE OIL AND GAS

Shale oil and gas reserves are hydrocarbons trapped in very tight or low permeability rock formations.[62] Typically, these resources can only be recovered via hydraulic fracturing (or "fracking") – a process by which large volumes of water combined with lubricating chemicals and sand are injected into tight rock formations, creating small cracks that release the oil and gas.

Since shale resources are more diffuse and difficult to access, they require far more land than for conventional production. The number of wells required to produce a given volume of shale oil and gas is typically around ten times that of conventional onshore fields.[63] Decline rates also tend to be much higher, so more wells need to be drilled to maintain production.[64] Overall, therefore, shale production has a much larger environmental footprint than conventional production, with potential habitat degradation implications (soil erosion, biodiversity loss, etc.).[65,66]

Land use requirements are partly why shale assets have only been developed at industrial scales to date in North America which has large regions of low population density. In contrast, much of Europe's shale resource is near population centres, which has increased social opposition to their development.[67]

The large number of production wells means shale operations produce overall more local pollution than conventional oil and gas.[68] Air pollution such as fine particulate matter as well as Nox and non-methane volatile organic compounds arise during exploration, site clearing, road construction, drilling, and well completion which involve significant amounts of diesel use by heavy equipment. All can be damaging to health.[69] One study showed concentrations of diesel fumes downwind from fracking sites were around three times higher than in typical Western cities.[70]

There is also evidence of indirect links between hydraulic fracturing and increased seismic activity. Although fracking itself does not generally lead to earthquakes, the storage of large volumes of wastewater in burial wells (which helps avoid groundwater contamination) has been linked to increased seismic activity.[71] Such earthquakes are usually relatively low intensity – with the largest fracking induced earthquake on record only reaching 4.0 in magnitude (the threshold for damage

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[60] Beyer et al. (2016) *Environmental effects of the Deepwater Horizon oil spill: A review.*

[61] BP (2010) *Deepwater Horizon Accident Investigation Report.*

[62] For the purposes of this report, we include tight oil/gas and coal bed methane under this heading.

[63] IEA (2013) *Special Report: Golden Rules for a Golden Age of Gas.*

[64] Wachtmeister and Hook (2020) *Investment and production dynamics of conventional oil and unconventional tight oil: Implications for oil markets and climate strategies.*

[65] IEA (2013) *Special Report: Golden Rules for a Golden Age of Gas.*

[66] Drohan et al. (2012) *Early trends in landcover change and forest fragmentation due to shale-gas development in Pennsylvania: a potential outcome for the Northcentral Appalachians.*

[67] Stephenson M (2015) *Shale gas in North America and Europe.*

[68] Moore et al. (2015) *Air Impacts of Increased Natural Gas Acquisition, Processing, and Use: A Critical Review.*

[69] Zielinska et al. (2004) *Emission rates and comparative chemical composition from selected in-use diesel and gasoline-fuelled vehicles.*

[70] Ezani et al. (2018) *Measurement of diesel combustion-related air pollution downwind of an experimental unconventional natural gas operations site.*

[71] US Geological Survey: *Does fracking cause earthquakes?*; Hincks et al. (2018) *Oklahoma's induced seismicity strongly linked to wastewater injection depth.*

to begin occurring is, broadly speaking, at magnitudes greater than 4.0-5.0 on the Richter scale).[72] Nonetheless, such seismicity risks are certainly concerning, particularly for local populations. However, with the correct management systems supported by government policy, such as pre-development seismic characterisation, monitoring storage reservoir pressures to ensure they do not exceed pre-production levels, and distributing volumes across multiple well, these risks can be mitigated.[73]

The hydraulic fracturing process uses substantial amounts of water, but the main water-related environmental risk is chemical contamination. Although fracking uses significantly more water than conventional extraction, recent studies suggest that even in arid or semi-arid regions the impact on the water table and overall water availability appears limited – in the US, freshwater use in fracking represents less than one percent of total industrial water consumption.[74] Much of the water used in fracking comes back up the well once pressure is reduced. This is called produced water and includes salts dissolved from the underlying rock as well as chemicals added as part of the extraction process.[75] Produced water has the potential to contaminate nearby fresh water used for drinking, agriculture, livestock, and local wildlife.[76,77] However, environmental impacts can be mitigated by recycling and reusing wastewater via integrated on-site wastewater treatment facilities that reduce freshwater demand and the potential for contamination.[78,79]

In summary, shale oil and gas extracted via hydraulic fracturing has a greater local environmental impact than conventional resources, providing rationale for an accelerated phase out. However, its risks are typically lower than other unconventionals, such as oil sands, and some mitigation options, such as wastewater treatment and recycling, exist. We find this conclusion to be consistent with other comparison studies on the matter.[80]

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[72] US Geological Survey: *At what magnitude does damage begin to occur in an earthquake?*

[73] Sun et al. (2019) *A critical review of risks, characteristics, and treatment strategies for potentially toxic elements in wastewater from shale gas extraction.* Hui et al. *(2022) Mitigating risks from hydraulic fracturing-induced seismicity in unconventional reservoirs: case study.* Menefee and Ellis (2020) *Wastewater management strategies for sustained shale gas production.*

[74] Hitaj et al. (2020) *Fracking, Farming, and Water.*

[75] Shrestra et al. (2017) *Potential water resource impacts of hydraulic fracturing from unconventional oil production in the Bakken shale.*

[76] Torres et al. (2016) *A review on risk assessment techniques for hydraulic fracturing water and produced water management implemented in onshore unconventional oil and gas production.*

[77] US EPA (2016) *Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States.*

[78] Sun et al. (2019) *A critical review of risks, characteristics, and treatment strategies for potentially toxic elements in wastewater from shale gas extraction.*

[79] Menefee and Ellis (2020) *Wastewater management strategies for sustained shale gas production.*

[80] EY (2017*) Unconventional oil and gas in a carbon constrained world.*

ANALYSIS 4: CONSIDERATION OF SUPPLY

Based on our analysis so far, we see a combination of climate and environmental arguments for accelerated phase outs across all types of unconventionals, potentially before such assets might otherwise be phased out based on economics alone. Any accelerated phase outs, however, would need to account for consequent impacts on global and regional supply versus demand in a 1.5°C scenario. Such impacts are considered in the following section of the paper, with the analysis split across oil and gas, respectively. It is important to note that regional hydrocarbon security of supply, and the geopolitical and economic issues that come with it, can be a highly complex and politically fraught topic. Accordingly, we present a simplified analysis for consideration which covers some of the key supply issues involved, though we recognise that it does not comprehensively cover all potential concerns.

OIL

At a global level, there are enough developed and under-development reserves to accommodate an accelerated phase out of all unconventional oil types: Oil sands and extra-heavy oil, Arctic oil, ultra-deepwater oil, and shale oil. Total IEA NZE demand out to 2050 is projected to be 670 billion bbl, whilst total developed and under-development oil reserves are estimated to be 966 billion bbl, a 30% surplus. Unconventional oil types represent an estimated 19% of total developed/under-development reserves, or 183 billion bbl. These could all be phased out, therefore, and still leave an excess supply of 113 billion bbl of reserves (see Exhibit 9, panel A).

However, whilst there might be enough conventional oil within existing fields to meet total demand in a 1.5°C scenario, we must also consider the rate at which this oil can be extracted. Unconventional oils make up an estimated 27% of total production each year (Exhibit 9, panel B). An accelerated phase out of these assets over the next few years, therefore, could result in a supply shortfall before conventional assets are able to ramp up production commensurately. Such production increases would require additional, or fast-tracked investments in existing conventional fields. Whilst investment in existing fields is consistent with IEA NZE the extent of the required ramp up could leave potential for large, long-term expansion projects deemed less desirable given their associated infrastructure lock-in and stranded asset risks.

Nonetheless, based on an analysis of IEA projections, there is still scope for an accelerated phase out of most, if not all, unconventional oils without causing a material shortfall in global supply. Under IEA NZE, oil demand is projected to fall by roughly 20 Mb/d by 2030. Over the same period the IEA projects supply at existing fields will decline by 18 Mb/d and be offset by the ramp up of under-development conventional projects, which will provide around 6 Mb/d of supply, as well as some expansion of existing shale/tight oil.[81] This leads, by our calculations, to an overall supply surplus of roughly 9 Mb/d by 2030 (Exhibit 9, panel C).

Assuming an accelerated phase out takes roughly 10-15 years to complete, with production of associated assets reaching zero by 2035, then there is scope to phase out oil sands, extra-heavy oil, Arctic oil, and ultra-deepwater oil whilst still maintaining around 4 Mb/d of supply surplus in 2030. Shale oil can be mostly phased out without any need for compensating action. A complete phase out would result in a net 2 Mb/d deficit that would potentially need to be offset through increased conventional production elsewhere, equating to a ~3% uplift in remaining assets (Exhibit 9, panel

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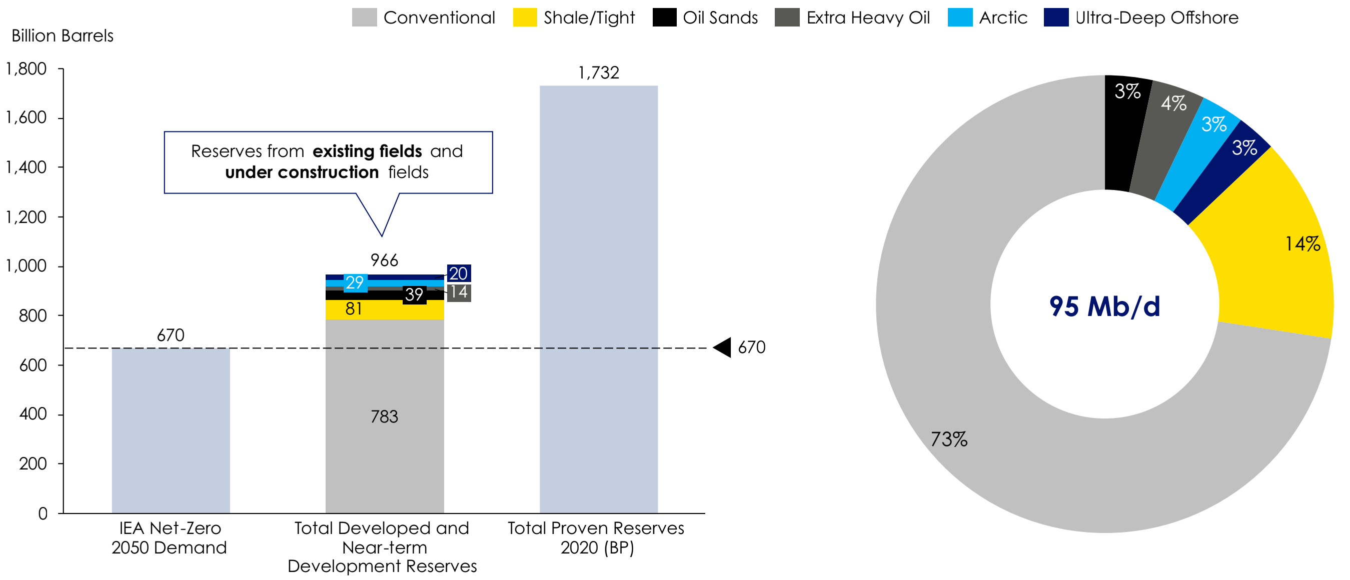
[81] IEA (2022) World Energy Outlook.

D). However, we do note that, given the co-location of shale oil and gas, an approach which keeps shale gas-focused assets (for which there is a strong case – see next section) and phases out shale oil-focused assets would still maintain ~20-50% of annual shale oil production volumes as a by-product.[82]

Exhibit 9: *Oil reserves and production volumes, by asset type, versus projected demand in IEA NZE*

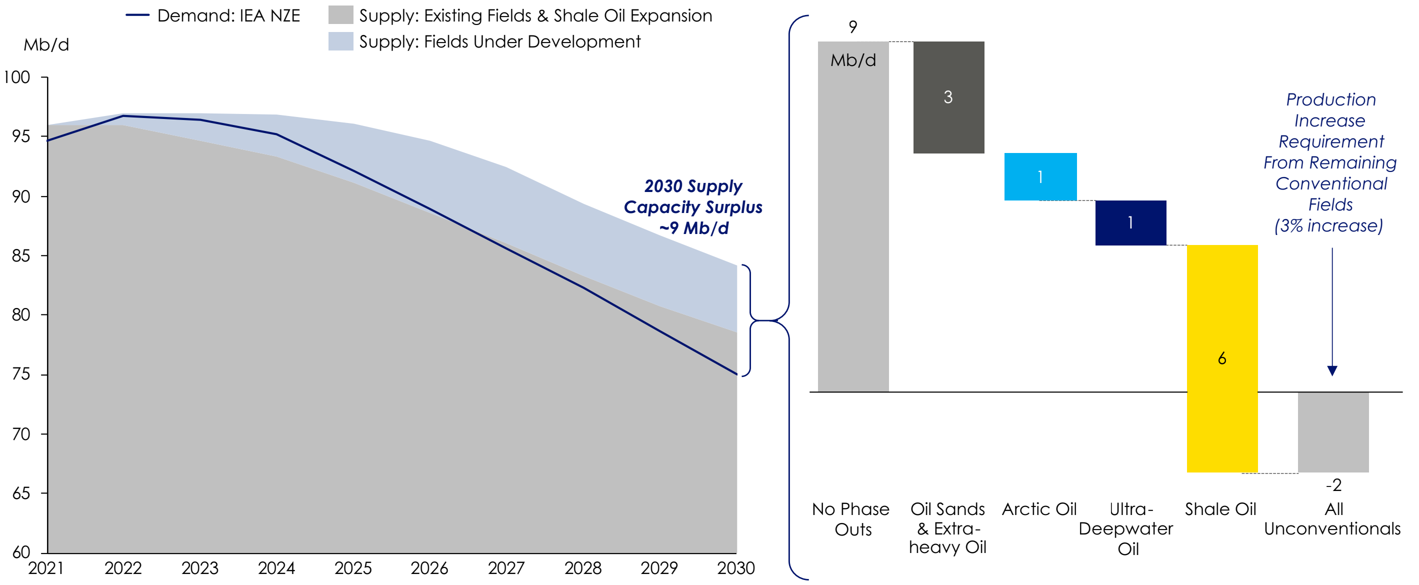
PANEL A: Oil reserves vs. IEA NZE cumulative demand (2020-2050)

PANEL B: Estimated annual oil production share by asset type (2021)



PANEL C: Projected oil demand vs. supply 2021 – 2030 (IEA NZE)

PANEL D: 2030 supply surplus/deficit by unconventional phase out case



NOTES: Total developed reserves taken from Trout et al. (2022), as of January 2018, and total near-term development reserves taken from GOGEL (2022) based on a review of global oil and gas expansion project commitments as of 2021. Unconventional reserves and production breakdown based on multiple sources below and Systemiq analysis.

SOURCES: BP (2021) *Statistical Review of World Energy*; IEA (2021) *Net Zero by 2050*; IEA (2022) *World Energy Outlook*; Trout et al. (2022) – *Existing fossil fuel extraction would warm the world beyond 1.5°C*; Canada Energy Regulator (2022) *Estimated Production of Canadian Crude Oil and Equivalent*; Global Oil and Gas Exit List, GOGEL (2022); Planète Énergies (2015) *Offshore Oil and Gas Production*; Reclaim Finance (2021) *Protecting the Arctic From Oil and Gas Expansion*; Jørgensen-Dahl (2007) *Arctic Oil and Gas*; EIA (2015) *World Shale Resource Assessments*; EIA (2022) *U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2020*; Systemiq Analysis (2022); IEA (2022) *Energy Fact Sheet: Why does Russian oil and gas matter?*; Energy Monitor (2022) *The enduring threat to the Arctic from Big Oil*.

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[82] Shale oil and gas are often found in reservoirs together. For segmentation purposes we may label a shale asset as "gas" if >50% of combined production (in boe) is gas, and vice versa for oil. An analysis of shale oil and gas fields (using RMI OCI+ data) shows that a 50% production threshold enables the capturing of fields currently producing 88% of shale gas and 18% of shale oil as a by-product. If the gas production threshold is decreased to 20%, then assets providing 97% of gas supply and 54% of oil supply are captured.

Oil can be traded globally, however significant reductions in domestic supply and an over-reliance on foreign imports, particularly when concentrated in a few countries, can introduce local energy security risks.[83] Accordingly, whilst an accelerated phase out of most or all unconventional oil types appears feasible from a global perspective, it could have a disproportionate impact on supply in the Americas, where production is concentrated. For example, oil sands production almost exclusively occurs in Canada, representing 65% of domestic output.[84] Likewise, shale oil has only really been developed at industrial scales, to date, in the US and also represents 65% of the country's oil production.[85] Over 90% of global ultra-deepwater oil is in the US Gulf of Mexico and offshore Brazil, though it plays a larger role in domestic supply for Brazil than for the US at 30% and 5%, respectively.[86] Finally, extra-heavy oil makes up around 20% of oil production in Mexico, and 45% in Venezuela.

Today, these countries generally produce as much or more oil than they consume. To test the local impact of an accelerated phase out of unconventional assets we modelled the demand and supply in a 1.5°C scenario for each country up to 2035, the assumed date by which an accelerated phase out would complete, and overlaid a series of cases ranging from 'no phase outs' of unconventional oil assets to 'full phase outs', and everything in between (see Exhibit 10).

First, we modelled oil demand reductions for each country, assuming a decline of 50% by 2035 for developed countries (USA, Canada) and a decline of 30% for developing countries (Brazil, Mexico, Venezuela) recognising the likely different decarbonisation rates for each group. This segmentation, if applied across OECD (50% decline) and non-OECD (30% decline) countries globally is consistent with an overall reduction in oil demand of approximately 39% by 2035, in line with the average decline from multiple 1.5°C scenarios (see Exhibit 1).

Oil supply forecasts assumed no new fields were developed, and production therefore declined at 4% per annum out to 2035, in line with IEA guidance (and allowing some investment in existing fields to maintain output).[87] The demand and supply projections for 2035, split out by conventional and unconventional oil types, are shown in Exhibit 10 (panel A). Exhibit 10 panel B shows, for a given phase out case, the level of domestic oil production as a percentage of domestic oil demand in 2035. For example, if Mexico were to phase out extra-heavy oil and oil sands (Case 2) then it could still meet 90% of domestic demand through other local sources of production.

A full phase out of all unconventionals (Case 5) would lead to a significant domestic supply gap for the group of countries, most notably for the US, Canada, and Brazil, turning the region into a net importer (with domestic output meeting 43% of demand). These countries could argue that, whilst adequate oil supply could be sourced on the global market, this scenario would lead to increased local energy security risks.

Considering each country in turn, the US can accommodate an accelerated phase out of Arctic and ultra-deepwater oil assets whilst continuing to meet 96% of oil demand domestically. Phasing out all shale oil in parallel would reduce domestic supply to 30% of demand. Canada can phase out oil sands by 2035 and still meet 84% of demand domestically. If it were to in parallel phase out shale oil, then local supply would fall to 61% of demand. In these two cases, however, we refer to our previous note that maintaining shale gas-focused assets would still yield ~20-50% of shale oil production as a co-located by-product, which would go some way towards mitigating energy security concerns. Mexico and Venezuela should both be able to phase out extra-heavy oil and

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[83] See, for example, the oil crisis of the 1970s and more recently, though the issue is principally around gas imports, Russia and Europe.

[84] Canada Energy Regulator (2022) *Estimated Production of Canadian Crude Oil and Equivalent.*

[85] EIA (2022) *How Much Shale (Tight) Oil is Produced in The United States?*

[86] EIA (2016) *Offshore Oil Production in Deepwater and Ultra-Deepwater is Increasing.* Note that Nigeria and Angola are also smaller producers.

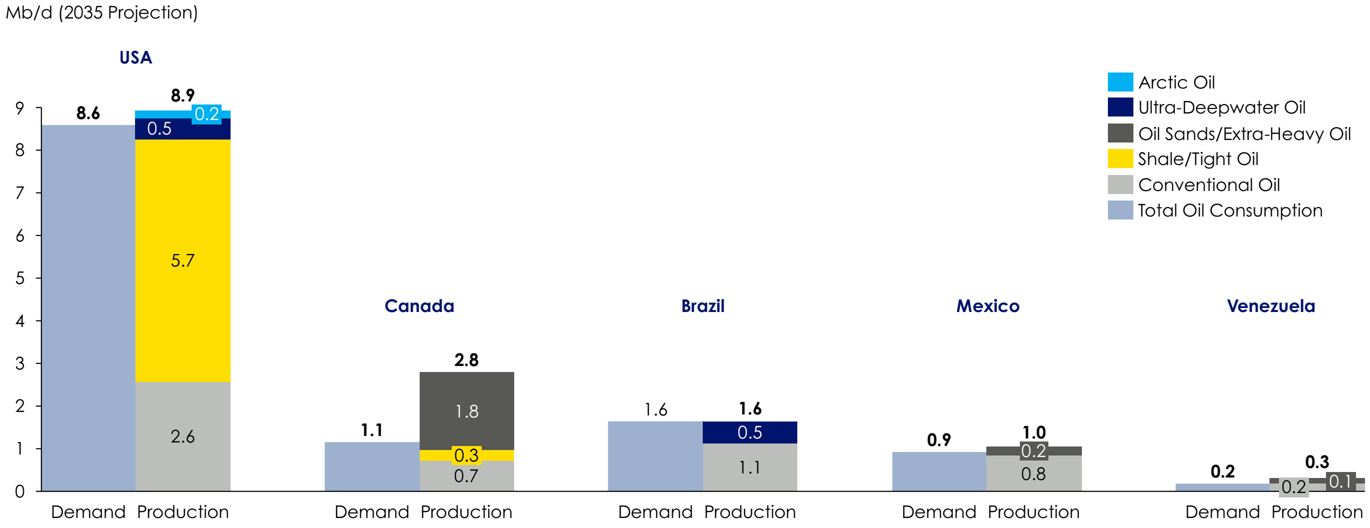
[87] IEA (2021) *Net Zero by 2050.*

still meet more than 90% of demand locally. Brazil would see domestic supply fall to 69% of demand if it phased out its ultra-deepwater assets.

Accordingly, a scenario where oil sands, extra-heavy oil, and Arctic oil are phased out, ultra-deepwater oil is only partially phased out (in the US and not Brazil), and existing shale oil is mostly maintained or only partially phased out (at least in the near to medium term) might be an appropriate way forward that still enables the elimination of the more expensive, carbon intensive and environmentally risky asset types whilst also maintaining local security of supply. Finally, we note that the faster a country decarbonises and decouples its economy from hydrocarbons, the lower the overall energy security risk to said economy of reduced domestic supply and therefore the greater the case for accelerated phase-outs of these environmentally risky asset types.

Exhibit 10: *Oil production and consumption in 2035 for US, Canada, Mexico, Venezuela, and Brazil in a range of unconventional oil phase out cases*

PANEL A: Regional oil demand and supply in 2035 for key Unconventionals producing countries in the Americas (US, Canada, Mexico, Venezuela, Brazil)



2035 Domestic Production as % of Domestic Consumption	**USA**	**Canada**	**Brazil**	**Mexico**	**Venezuela**	**Full Group**
Case 1: No Accelerated Phase Outs	104%	244%	101%	113%	173%	**118%**
Case 2: Phase out Oil Sands & Extraheavy Oil	104%	84%	101%	90%	93%	**101%**
Case 3: Phase out Oil Sands, Extraheavy Oil, Arctic	102%	84%	101%	90%	93%	**99%**
Case 4: Phase out Oil Sands, Extra-heavy Oil, Arctic, Ultra-deepwater	96%	84%	69%	90%	93%	**91%**
Case 5: Accelerated Phase Out For All Unconventionals	30%	61%	69%	90%	93%	**43%**

NOTES: Analysis covers US, Canada, Mexico, Venezuela, and Brazil as a collective region. 2020 production and consumption figures taken from BP Statistical Review of World Energy and split between unconventional types using sources below. For each of the unconventional phase out scenarios in the table we show the domestic supply margin, i.e., total domestic oil production divided by total domestic oil consumption in 2035, as an indicative view of local security of supply. Figures >90% are shaded green, figures 80-90% are shaded amber, and figures <80% are shaded red.

SOURCES: BP (2021) *Statistical Review of World Energy*; EIA (2016) *Offshore Oil Production in Deepwater and Ultra-Deepwater is Increasing*; EIA (2022) *How Much Shale (Tight) Oil is Produced in The United States?*; Global Oil and Gas Exit List, GOGEL (2022); Canada Energy Regulator (2022) *Estimated Production of Canadian Crude Oil and Equivalent*; S&P Global (2019) *Venezuela's Orinoco Belt Crude Production Falls to 246,000 b/d: Technical Report*; IEA (2021) *Net Zero by 2050; Systemiq analysis (2022).*

Non-US Arctic oil is principally concentrated in Russia, representing an estimated 20% of the country's oil production.[88,89] Russia is a major net exporter, with plenty of local supply. Non-Arctic Russian oil production represents three-times total domestic consumption, so local security is not a concern. Conversely, Russian oil accounted for around 25% of European oil imports in 2021, and while it is unclear what proportion of that came from the Arctic,[90] an accelerated phase out of Arctic oil would have had implications for European regional energy supply. However, Russia's invasion of Ukraine has forced Europe to seek new energy partners and diversify its supply. The historically strong hydrocarbon trade routes between Europe and Russia are therefore undergoing a major decoupling, a situation the IEA has assumed to be permanent in the modelling for their latest World Energy Outlook.[91]

In summary, whilst all unconventional oil types can be phased out globally, there may be arguments for only pursuing a partial phase out of ultra-deepwater and shale oil based on regional energy security concerns.

NATURAL GAS

At a global level, an accelerated phase out of ultra-deepwater gas is feasible. However, some degree of existing shale and Arctic gas will still be required going forward (see Exhibit 11). Total developed and under-development natural gas reserves are estimated to be 102 Tcm, whilst projected demand out to 2050 in IEA NZE is 79 Tcm. Oversupply for gas is smaller than for oil, and the demand reduction curve less steep, leaving less room for an accelerated phase out of existing unconventional assets. At a global level, ultra-deepwater gas reserves are estimated to be 3 Tcm, or just 3% of total. Annual ultra-deepwater gas production is also roughly 3% of global supply, or ~150 Bcm. With such a small share, therefore, this asset type can feasibly be phased out without materially impacting global supply. Furthermore, the IEA estimates that 260 Bcm of natural gas is wasted each year through flaring, venting, and leakage, of which 210 Bcm may be economically brought to market, enabling such gas to more than plug any potential supply gap left by an accelerated phase out of ultra-deepwater assets.[91]

Arctic gas and shale gas, on the other hand, represent around 20 Tcm (20%) and 16 Tcm (16%) of total developed and under-development gas reserves, respectively. Such volumes mean it's not possible to phase out these asset types globally, without developing significant replacement sources of conventional gas. New conventional gas projects, however, are capital intensive and have long lead times (up to 20 years from the granting of an exploration licence to the start of production).[91] Therefore, phasing out existing unconventional gas in favour of new conventional sources could result in near-to-mid-term supply gaps, divert investment away from other vital transition areas such as low-carbon energy, and increase the risk of hydrocarbon infrastructure lock-in effects and stranded assets. There is potentially room at a global level for a partial phase out of Arctic and shale gas, given total developed and under-development reserves (excluding ultra-deepwater gas) are still 25% higher than IEA NZE projected demand out to 2050. Given the significant environmental risks associated with Arctic assets (as identified in Analysis 3 of this paper) the prioritised retirement of these over shale gas is encouraged, where possible.

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[88] Note: Norway is also a smaller Arctic oil and gas producer, with output levels similar to the US. Arctic oil and gas production in Norway represents ~0.5 Mboe per day, or ~10% of the country's total oil and gas output (see: Energy Monitor (2022) and BP Statistical Review (2021)).

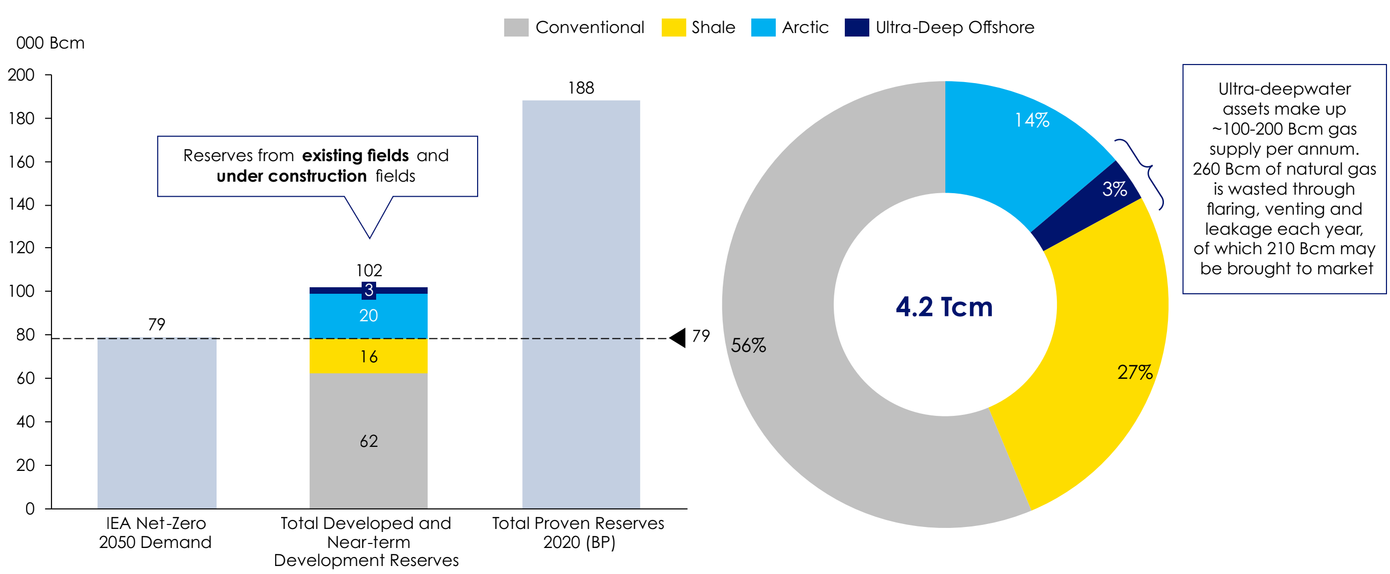
[89] IEA (2022) *Energy Fact Sheet: Why does Russian oil and gas matter?*; BP (2021) *Statistical Review of World Energy*; Energy Monitor (2022) *The enduring threat to the Arctic from Big Oil.*

[90] Eurostat (2022) *EU Imports of Energy Products - Recent Developments.*

[91] IEA (2022) *World Energy Outlook.*

Gas markets are not global and we must consider regional supply and demand balances that rely on infrastructure such as pipelines and liquefied natural gas (LNG) import and export facilities. Shale gas production is concentrated in North America with the US producing 90% of global supply (remaining production being spread across Canada, China, and Argentina).[92] Within the US, shale gas is responsible for the vast of majority of output, representing 85% of the country's natural gas production. Most of this is consumed domestically, with the country being effectively self-sufficient.[93] An accelerated phase out of shale gas, therefore, could have significant implications for US regional security of supply. We also note that the EU and other blocks are likely to be dependent on exported LNG from shale gas resources in the short-medium term, following reduced flows from Russia.

Exhibit 11: *Natural gas reserves and production volumes, by asset type, versus projected demand in IEA NZE*



PANEL A: Gas reserves vs. IEA NZE cumulative demand (2020-2050)

PANEL B: Estimated annual gas production share by asset type (2021)

NOTES: Total proven reserves of oil/gas–generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions (i.e., already discovered fields). Reserves include gas condensate and natural gas liquids (NGLs) as well as crude oil. Total developed reserves taken from Trout et al. (2022), as of January 2018, and total near-term development reserves taken from GOGEL (2022) based on a review of global oil and gas expansion project commitments as of 2021. Unconventional reserves and production breakdown based on multiple sources below and Systemiq analysis.

SOURCES: BP (2021) *Statistical Review of World Energy*; IEA (2021) *Net Zero by 2050*; IEA (2022) *World Energy Outlook*; Trout et al. (2022) – *Existing fossil fuel extraction would warm the world beyond 1.5°C*; Canada Energy Regulator (2022) *Estimated Production of Canadian Crude Oil and Equivalent*; Global Oil and Gas Exit List, GOGEL (2022); Planète Énergies (2015) *Offshore Oil and Gas Production*; Reclaim Finance (2021) *Protecting the Arctic From Oil and Gas Expansion*; Jørgensen-Dahl (2007) *Arctic Oil and Gas*; EIA (2015) *World Shale Resource Assessments*; EIA (2022) *U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2020*; Systemiq Analysis (2022); IEA (2022) *Energy Fact Sheet: Why does Russian oil and gas matter?*; Energy Monitor (2022) *The enduring threat to the Arctic from Big Oil*.

Unlike ultra-deepwater oil, the vast majority of which comes from Brazil and the US Gulf of Mexico, ultra-deepwater gas reserves are more distributed around the world. Supply comes from the US and Brazil, but also Africa and the Middle East (Mozambique, Tanzania, Egypt, Israel), and Asia Pacific (India, China).[94] Given this spread, alongside its relatively small share of global production, an accelerated phase out of ultra-deepwater gas is less likely to have a material impact on security of supply in any single region. Nonetheless, some producing countries may deem their ultra-deep gas assets to be strategically valuable. Israel, for example, despite being only a small

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[92] Statistia (2016) *Shale gas production worldwide in 2015 and 2040, by selected country.*

[93] EIA (2022) *Natural gas explained: Where our natural gas comes from.*

[94] Offshore Technology (2018) *Ultra-deepwater gas production set to triple by 2025*; and Wood Mackenzie (2019) *Deepwater rising: The state of the global deepwater industry*; China Daily (2021) *China's 1st large-scale, ultra-deepwater gas field opens.*

hydrocarbon consumer, views the Tamar and Leviathan offshore gas fields as key to its local energy security.[95] Since the breaking of hydrocarbon trade links with Russia, Europe is also taking an interest in these sites.[96]

Like Arctic oil, Arctic gas production is concentrated in Russia, which represents over 90% of global supply.[97] Arctic gas makes up 80% of the country's total gas production, equating to 520 Bcm per annum.[98] Much of this is consumed at home, with most of the rest being exported, historically, to Europe.[99] This Europe-Russia gas corridor has traditionally been a core part of regional energy security. However, since the invasion of Ukraine, this is no longer the case. With a major decoupling underway, Europe is now seeking new, diversified sources of supply.[100] Russia will therefore need to find new export markets for its Arctic gas, and, in the latest World Energy Outlook, the IEA predicts it will struggle to establish these to the same extent. Accordingly, the country, and its Arctic gas supplies, will play a reduced role in global and regional energy markets going forward.

If export markets are less of a concern, domestic supply could still be an issue. Russia is the second largest consumer of natural gas in the world, behind the US and ahead of China, consuming an average of 430 Bcm per annum 2017-2020.[99] If all Russian Arctic gas were phased out then conventional production would equate to 130 Bcm per annum, or just 30% of current local consumption needs. In short, the country would shift from being a net exporter to a significant net importer. As with shale gas for North America, this is likely not a credible scenario. Therefore, there could be a valid argument against an accelerated phase out of Arctic gas based on a consideration of local Russian energy security. Nonetheless, we note that only 50-60% of Russian Arctic gas is required to cover domestic consumption, so there is potential room for a partially accelerated phase out of the most environmentally impactful assets.

In summary, ultra-deepwater gas can be phased out at a global level. However, there may be localised strategic supply arguments which would instead favour a partial phase out or phase down. Some degree of shale and Arctic gas will still be required, globally, in a 1.5°C scenario. There are further regional security of supply arguments for keeping existing shale gas and only pursuing a partial phase out of Arctic gas. In order of their environmental impact, we would encourage Arctic gas assets to be retired ahead of shale gas assets, where possible.

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[95] Times of Israel (2021) *Tamar gas field discoverer: Israel's security demands gas reserve for 40 years;* Ashwarya S. (2020) *Natural Gas Discoveries and Israel's Energy Security.*

[96] OSW Centre for Eastern Studies (2022). *Israel's Mediterranean gas: the potential for gas export to Europe and the dynamic of regional cooperation.*

[97] Energy Monitor (2022) *The enduring threat to the Arctic from Big Oil*; Jørgensen-Dahl (2007) *Arctic Oil and Gas.*

[98] Russian gas production is ~650 Bcm per annum, and Arctic assets represent ~80% of this (~520 Bcm). Russian Arctic gas represents >90% of global Arctic gas. See: IEA (2022) *Energy Fact Sheet: Why does Russian oil and gas matter?*; BP (2021) *Statistical Review of World Energy*; Energy Monitor (2022) *The enduring threat to the Arctic from Big Oil.*

[99] BP (2021) *Statistical Review of World Energy.*

[100] We note that whilst pipeline imports of Russian Arctic gas have reduced significantly since the invasion of Ukraine, Europe is still purchasing Russian Arctic LNG, and indeed import volumes of LNG have gone up year on year. However, these LNG imports are an order of magnitude smaller than Russian pipeline imports at 10-15 Bcm per annum versus 100 Bcm+ for pipeline gas. Accordingly, we still see a much-reduced role for Russian Arctic gas in European markets going forward. For further information see Politico (2022) *The Russian gas habit Europe can't quit: LNG.*

CONCLUSIONS

A broader consideration of oil and gas assets can enable a phase down approach consistent with a 1.5°C pathway that minimises negative externalities, such as carbon emissions, whilst meeting energy needs. Based purely on a consideration of cost, it is likely that many unconventional asset types will remain active in the 2030s and beyond in a declining demand scenario (ultra-deepwater, shale, and the most cost-competitive extra-heavy oil/oil sands and Arctic assets). However, in addition to cost, we argue other factors should come into play, such as greenhouse gas emissions intensity, local environmental risks/impacts, and global and regional security of supply.

Unconventional assets typically perform worse than conventional ones against negative externalities, providing rationale for their accelerated phase out. Extra-heavy oil and oil sands assets have significantly higher GHG emissions intensities than other asset types as well as substantial environmental risks. Arctic and ultra-deepwater assets do not typically display higher emissions intensities but, whilst low likelihood, can have major local environmental impacts in cases of accidents and oil spills. For shale oil and gas, emissions intensities are not noticeably higher than for conventional assets, but there are increased local environmental risks.

However, some unconventionals have become significant parts of global and regional supply, meaning accelerated phase outs could have negative energy security implications. In a 1.5°C energy demand scenario, existing extra-heavy oil, oil sands, and Arctic oil assets can be phased out without materially impacting global or regional security of supply. Whilst shale oil and ultra-deepwater oil can also be phased out at a global level, doing so could have potential regional energy security implications for the Americas.

For natural gas, an accelerated phase out of ultra-deepwater assets is feasible without materially impacting global supply, though there could be some localised concerns (e.g., the Tamar and Leviathan fields).[101] Most developed and under-development shale and Arctic gas reserves are still required at a global level for the energy transition, or else must be replaced with new sources of conventional gas. There are further regional security of supply arguments for keeping existing shale gas and only pursuing a partial phase out of Arctic gas. Regardless of the potential for accelerated phase outs, there is still significant opportunity across all asset types to reduce emissions by investing in abatement technologies, with a particular focus on upstream methane venting, flaring, and leakage (see Analysis 2).

It is necessary to differentiate between unconventional asset types as well as oil and gas supplies when considering potential accelerated phase outs and phase downs. We summarise our integrated conclusions in the image below (Exhibit 12):

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[101] Note: the Tamar and Leviathan fields are both 1,700m deep, and therefore one possible approach to managing such localised issues could be to set ultra-deepwater phase out depth thresholds appropriately. In this case a phase out depth of 2,000m would enable the Tamar and Leviathan fields to be maintained whilst phasing out deeper, and thereby riskier, assets elsewhere. However, this is just one potential approach.

Exhibit 12: *Accelerated phase out conclusions based on unconventional asset cost, emissions intensity, environmental risk, and energy security/supply requirements*

Resource	Type	Cost of Production (vs. Conventionals)	GHG Emissions Impact (vs. Conventionals)	Environmental Impact (vs. Conventionals)	Required Due to Global Supply Needs	Potential Regional Energy Supply Concerns	Accelerated Phase Out Conclusion
Extra-heavy Oil & Oil Sands	**Oil**	Mid-High	Consistently Higher	High (Rank 4)	No	No	**Yes**
Arctic Oil	**Oil**	Mixed (Low/High)	Not Consistently Higher *(Driven by Operational Practices)*	High (Rank 3)	No	No	**Yes**
Ultra-Deepwater Oil	**Oil**	Competitive		High (Rank 2)	No	Partially	**Partially**
Shale Oil	**Oil**	Competitive		Mid-High (Rank 1)	No	Yes	**Partially**
Arctic Gas	**Gas**	Competitive		High (Rank 3)	Partially	Yes	**Partially**
Ultra-Deepwater Gas	**Gas**	Competitive		High (Rank 2)	No	Partially	**Partially**
Shale Gas	**Gas**	Competitive		Mid-High (Rank 1)	Partially	Yes	**No**

NOTES: Environmental impact vs. conventional assets shows a ranking from 1-4 in order of impact, with 4 being the most impactful and 1 being the least impactful.

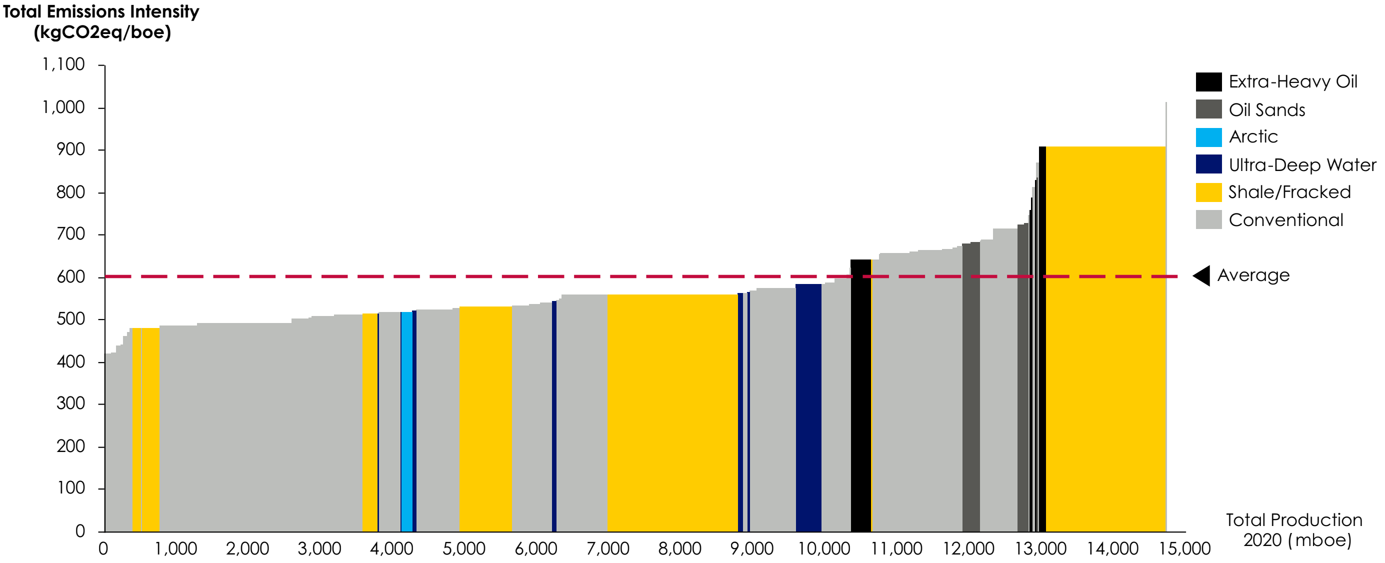
SOURCES: Systemiq analysis (2022).

Whilst the analysis in this paper has focused on managing hydrocarbon supply, it is important to recognise that (i) this is set within a 1.5°C energy transition pathway, (ii) such a transition will be demand-driven, and (iii) a parallel acceleration of clean energy and infrastructure investment will be critical. Prematurely phasing down fossil-fuel supply before achieving the appropriate reductions in demand could bring substantial negative economic and social consequences. Society's priority, therefore, should be an immediate and rapid scale up in the deployment of clean energy and infrastructure, energy storage, the electrification of mobility and buildings, and the decarbonisation of industry worldwide.

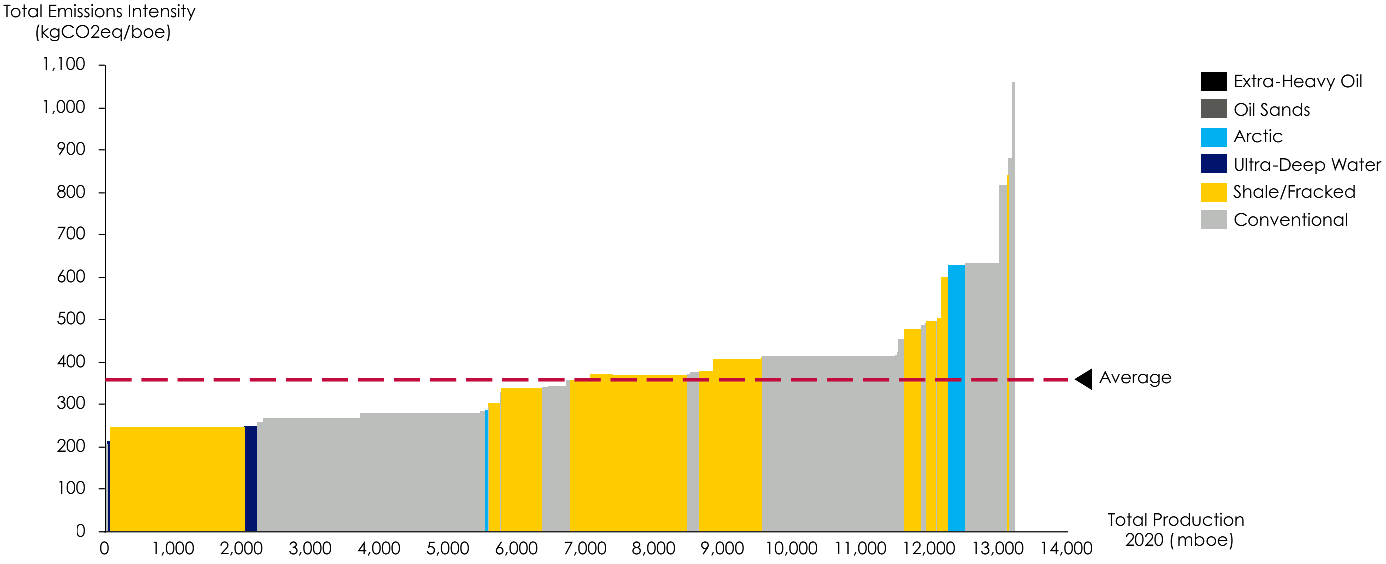
APPENDIX

Exhibit A1: *GHG emissions intensity by oil and natural gas field for conventional and unconventional resource types 2020 (50% of global production); 20-year GWP*

PANEL A: Oil Fields



PANEL B: Natural Gas Fields



NOTES: Data shown for 50% of the world's oil and gas production in 2020 including condensates. Emissions intensity calculated using Global Warming Potential (GWP) over 20-year period for total lifecycle emissions (upstream, midstream & downstream). Average refers to production weighted mean across all fields. Arctic defined here as the 'Arctic Circle', latitude of 66.33° north of the Equator.

SOURCES: RMI (July 2022) – Oil Climate Index + Gas Model v.1.0, 2022; Systemiq Analysis (2022).

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