

Unconventional oil and gas in a carbon constrained world

A review of the environmental
risks and future outlook for
unconventional oil and gas

September 2017

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The report has been developed by EY in collaboration with KLP. The report was published in September 2017.

Contact EY:

Hanne Thornam

E-mail: hanne.thornam@no.ey.com

Contact KLP:

Annie Bersagel

E-mail: annie.bersagel@klp.no

Executive Summary

Unconventional oil and gas has seen a rapid rise over the last decade, as new technologies have allowed development of oil and gas reservoirs unreachable or uneconomical with conventional production methods. This has led to questions regarding the environmental impacts of increased unconventional oil and gas production, and whether such production is compatible with a more sustainable, low-carbon future.

Of all unconvensionals reviewed, oil sands pose the overall highest environmental risks, comparable only to coal mining

Both of the techniques used to extract oil sands, open mining and in situ production, have severe environmental consequences. Open mining can be particularly damaging, as large incisions into natural landscapes can leave irreversible damage, and severely impact surrounding wildlife. Newer in situ technology has been touted as more environmentally friendly than open mining. However, in situ production still pose many of the same environmental risks to both land and water resources. All oil sand extraction is water intense, and can lead to local droughts and amplify regional water stress, and spills of toxic wastewater and mining residuals can contaminate both surface and ground water resources. Oil sand has also been found to be the highest single contributor to air pollution in Canada, impacting air quality on a regional level, with potential detrimental health impacts for local populations.

Oil sand extraction is also the most carbon intensive of the major unconvensionals

The high energy requirements of oil sand production cause 60-80% more greenhouse gas (GHG) emissions compared to conventional oil production, with in situ emitting more than open mining. Additionally, refining of oil sands produces large volumes of petcoke, which is often used for power generation. Burning petcoke causes GHG emissions comparable to coal, further exacerbating the total climate impact of oil sands.

Hydraulic fracturing of oil and gas entail higher environmental risks than conventional extraction methods

Hydraulic fracturing (fracking) uses sand, chemicals and water to crack open impermeable rock formations to stimulate the flow of oil and gas. This has allowed for a rapid, large scale development of shale gas, tight gas and tight oil, primarily in the U.S. However, fracking wastewater containing high amounts of chemicals can leak or spill into surrounding landscapes and water resources, posing health and environmental dangers. GHG emissions from fracking are however largely comparable to conventional oil and gas.

Unconventional oil and gas face adverse market conditions in the short term, with analysts predicting growth only in long term "business as usual" scenarios

Low oil prices have posed new challenges for unconventional oil and gas, which have higher marginal costs than conventionals. Despite efforts to cut costs in fracking operations, low levels of investment has nonetheless stunted future growth. Analysts do however predict that OPEC will enforce production cuts within the short term, which could prevent a decline in fracking production. Open mining and in situ production of oil sands are however seen to be less competitive, due to larger projects, with higher marginal costs and initial investments. In the longer term, The IEA's "New Policies Scenario", which predicts moderate climate action, forecasts increasing demand for oil and gas, driven primarily by growth in industrializing economies, such as China and India. This would boost unconventional oil and gas, as conventional reserves are depleted.

Several scenarios present pathways for staying within 2°C global warming, but predictions for primary energy sources are highly uncertain

In the IEA scenario compatible with a 2°C target, the "450 Scenario", fossil fuel demand falls due to climate policies. Conventional oil production decreases, whilst unconventional oil sees marginal growth, albeit significantly lower than in the "business as usual" scenarios, with oil sands worst off. Less GHG intensive unconventional gas would be better off, displacing coal and experiencing slight overall growth. However, this IEA scenario rests on uncertain assumptions such as high growth in carbon capture and storage, and slow growth in renewable energy, to only 17% of world energy production in 2040. Other scenarios, by for example Bloomberg New Energy Finance, MIT or Greenpeace predict a higher share for renewables, leading to a steeper decline in unconventional oil and gas production. Electrification of transport is another uncertainty, and more rapid implementation would have similar downward impacts on unconventional oil production.

To be certain of staying within 2°C, most unconventional oil and gas reserves would have to remain unburned

unconventional oil and gas technologies depend on prolonged reliance on fossil fuels. This makes them less compatible with a 2°C future, as it is estimated that only one third of existing fossil fuel reserves can be burned if we are to reach this target. In an idealized case, where the remaining carbon budget was allocated according to marginal price and GHG emissions, all oil sands extraction would stop, leaving current reserves as stranded assets. Although slightly more hydraulically fractured tight oil and gas could be utilized, half of current reserves would need to remain unburned.

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1 Background and purpose

EY has written this study on commission from KLP. The purpose of the study is to give a detailed overview of the unconventional oil & gas industry with a focus on:

- ▶ Definitions of unconventional oil and gas
- ▶ Introduction to technologies and different types of unconventional oil and gas
- ▶ Environmental risks and GHG emissions
- ▶ Market outlook in short and long term
- ▶ Unconventional oil and gas under a carbon budget (2 °C climate scenario)

This study is intended to give KLP information on the unconventional oil and gas market as a whole, with an overview of relevant environmental risks. This will enable KLP to evaluate whether their investments within unconventional oil & gas are compatible with their investment policies.

The study is based on a limited literature review, where selected sources have been examined. Where well known and accredited sources are available these have been used in addition to academic research papers and meta studies to most accurately represent the scientific consensus on a given issue. In cases where limited information is available this will be reflected in the overall conclusions on the issue.

The information presented in this document is dependent on; the third party resources that were available at the time this study was developed, the time available for preparation of the report and the overall length of the report. As such this report should be considered a guidance document only and not a definitive study of the technologies presented.

2 Introduction to unconventional oil and gas

Unconventional oil and unconventional gas are terms generally used to differentiate oil and gas that has been extracted using techniques that differ from more established methods of production. This means that the oil and gas is extracted by methods other than drilling a vertical well into an oil or gas bearing formation from which the oil and gas naturally flows out in large quantities. These technologies often allow the extraction of oil and gas from fields that otherwise may not have been economically viable. The terms are not static however, and technologies that have been considered unconventional may later become conventional.

For simplicity this study follows IEA's categorization of unconventional oil and gas from the 2013 "Resources to Reserves" publication [1]. The technologies assessed will be; onshore hydraulic fracturing, open mining, in situ, gas to liquid (GTL) and coal to liquid (CTL). Unconventional oil & gas is further divided into categories according to their corresponding geological depository or source. In figure 2.1 an overview of this definition is given showing unconventional resources according to their extraction method. While other techniques exist for producing oil and gas, these will not be included in this report. For example methane hydrates, a source of gas still at the experimental stage, has not been included due to the lack of commercialization, while biofuels have not been included as they are

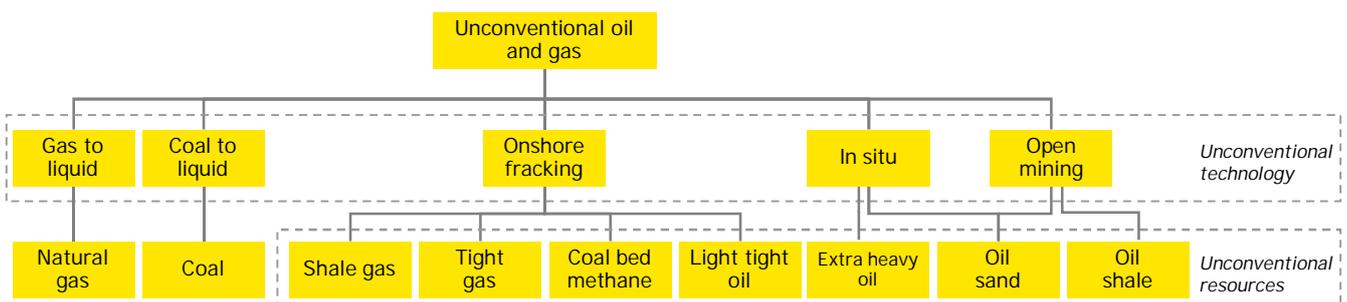
considered outside of the scope of this report. Unconventional offshore extraction, such as arctic drilling, ultra-deepwater or heavy oil, have not been included.

Chapter 2 and 3, which discuss definitions and environmental impacts of unconventional oil & gas respectively, have therefore been structured around the main categories of unconventional extraction technologies, with the specific characteristics associated with the various unconventional resources detailed in subchapters. This approach differs somewhat from the approach taken by the IEA which tends to group unconventional oil and gas according to their end product (oil, gas, etc.). The approach however allows for groupings that reflect the varying environmental impacts of extraction which are primarily linked to the technology in question.

Chapters 4 and 5 are however structured around resources instead of technology, as available literature uses this approach. Please refer to figure 2.1 for an overview of the difference between the technologies and resources.

This chapter will present an overview of the different unconventional technologies and their corresponding resource bases, including current production, available resources, reserves, and their geographical location.

Figure 2.1 - Definitions of unconventional oil and gas technologies and reservoirs



2.1 Oil and gas resources and production

Technically recoverable volumes of unconventional and conventional oil and gas are comparable, however production of unconventional oil and gas is lower than production from conventional sources

Oil and gas deposits are classified according to the development of these resources and how easily they can be retrieved using current technology. The text box on the right provides definitions of the terms that will be used throughout this report to denote the difference between oil and gas deposits that are economically attractive to extract, those it is possible to extract, and the estimated total deposits that experts think may be present.

Figures 2.2 and 2.3 show the total amount of oil and gas in the world broken down into unconventional (grey) and conventional (yellow) deposits by type. This shows that unconventional oil accounts for over half of all technically recoverable oil, while unconventional gas represents just under half of all recoverable gas. Figures 2.4 and 2.5 show that only 8,4% of oil produced in 2015 came from unconventional sources while 20% of the gas produced was unconventional.

In the following subchapters the technologies used to extract these resources are further described, with further detailed overview of production and resource types.

Definitions:

Reserves

IEA defines reserves as the portion of energy resources that are economically recoverable through the use of current technologies, and for which a project can be clearly defined. The definition of a reserve therefore depends on two factors, namely the current hydrocarbon price, as well as the breakeven cost associated with the available technology [1].

Technically recoverable resources

IEA defines this as resources with a higher degree of uncertainty of extraction, that are currently not economically but technologically feasible, and otherwise identified and proven [2].

Ultimately recoverable resources

IEA defines this as the estimated total oil and gas that is judged to be ultimately producible for commercial purposes. This term does not consider the current technological or economical feasibility [1].

Figure 2.2: % of technically recoverable resources of oil by resource type

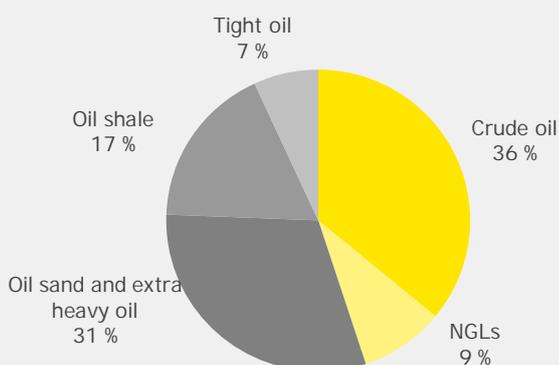


Figure 2.3: % of technically recoverable resources of gas by resource type

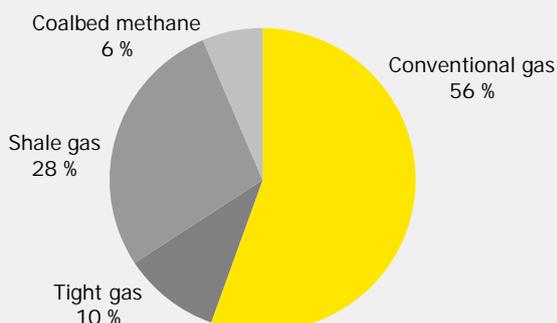


Figure 2.4: % of total oil production by production type in 2015

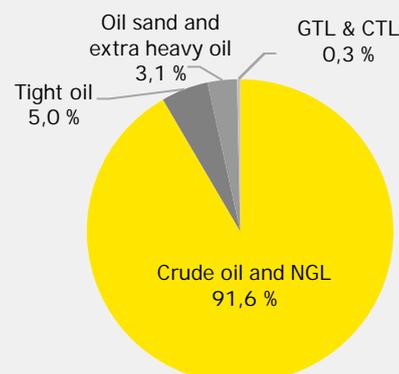
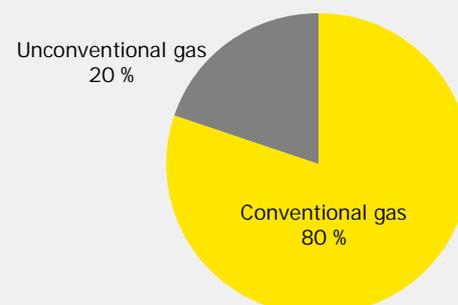


Figure 2.5: % of total gas production by production type in 2014



Source: Adapted from IEA World Energy Outlook 2016 [2]

2.2 Introduction to onshore hydraulic fracturing

Hydraulic fracturing or “fracking” is an extraction method in which fracking fluids, composed of large amounts of water mixed with sand and various chemicals, are injected into a well to create cracks in the impermeable reservoir

2.2.1 Production Method

Hydraulic fracking or “fracking” is a method used to extract resources which are not accessible to conventional oil and gas drilling. While conventional fields are based in drilling a well to pump oil or gas out of basins and large pockets within geological formations, hydraulic fracking instead targets oil and gas trapped within much smaller pockets in impermeable rocks, such as coal, sandstone and shale.

These formations prevent the oil or gas from flowing out of the well, making them hard to extract before fracking technology was developed to crack open the geological formations using high pressure fluids. To perform this operation, fracking fluids, which contain large amounts of water mixed with sand and chemicals, are pumped under high pressure into a horizontally drilled well. The high pressure cracks the impermeable reservoir (see figure 2.6) and the sand, known as proppant, holds open the cracks to allow the oil and gas to flow into the well. Once the fracking has been completed, pumping of the fluids is stopped. As the pressure subsides a mixture consisting of the fracking fluids, gas and potentially oil, known as flowback, comes up and out of the well. Most of the flowback will flow out of the well within the first 10 days [3], but the flow may continue for up to 3-4 weeks [4], until a steady stream of pure gas (and potentially oil) is established. The flowback makes up approximately 30% of the total fracking fluid volume initially injected into the well, depending on characteristics of the reservoir, while the remaining water remains underground [3].

Terms and Expressions:

Fracking

Short for fracturing – meaning to create cracks in a reservoir by inserting fracking fluid into the well under high pressure.

Fracking Fluid

A mixture of water, sand and various chemicals that is injected into the well to hydraulically fracture (frack) it.

Well Completion

The process of making a well ready for production.

Flowback

A mix of fracking fluid, gas and potentially oil that flows out of the well after a fracking operation.

Flaring

Controlled combustion of natural gas to avoid direct release of natural gas to the atmosphere.

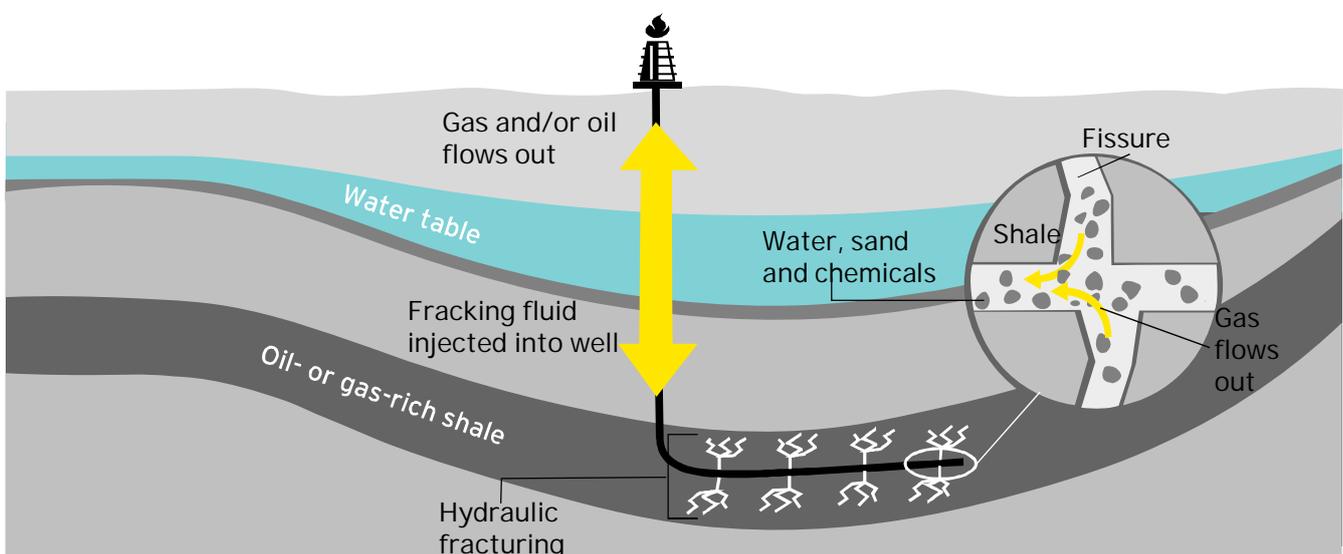
Venting

Controlled or uncontrolled direct release of natural gas to the atmosphere.

Impermeable formations

Geological formations where fluids cannot flow freely, due to lack of pores and cracks.

Figure 2.6 – Overview of hydraulic fracturing process



2.2 Introduction to onshore hydraulic fracturing

Hydraulically fractured unconventional oil and gas resources are located in small pockets in rock formations making them harder to access than conventional oil and gas resources

An important part of the fracking process, known as the well completion phase, is required to make a well ready for production. This involves complex operations to handle the flowback and minimize the impact on the environment, including removing and if necessary cleaning the water, and flaring or venting the gas. One way of dealing with the water, which is mixed with oil and fracking chemicals, is to drill a second well and pump the flowback into another reservoir for long-term storage or re-use it in another fracking operation. The environmental impact of the well completion phase is discussed further in chapter 3 of the report.

Directional or horizontal drilling enables access to more of the reservoir, which increases the effectiveness of the fracking process and thereby also the yield. By being able to turn the drill underground, greater parts of a reservoir that is spread over a large horizontal area can be accessed from a single well (see figure 2.7). This therefore reduces the total number of wells that need to be drilled in order to fully develop a field.

After well completion the well will produce gas and potentially oil until the pressure in the well equals the atmospheric pressure. Several technologies are available to stimulate the reservoir to further increased production. Alternatively, re-fracking is performed, or a new well is drilled.

2.2.2 Unconventional resources extracted through hydraulic fracturing

Fracking is an extraction method that can be used on different geological formations to extract both gas and oil. An illustrative explanation of the geology of natural gas resources is shown in figure 2.7.

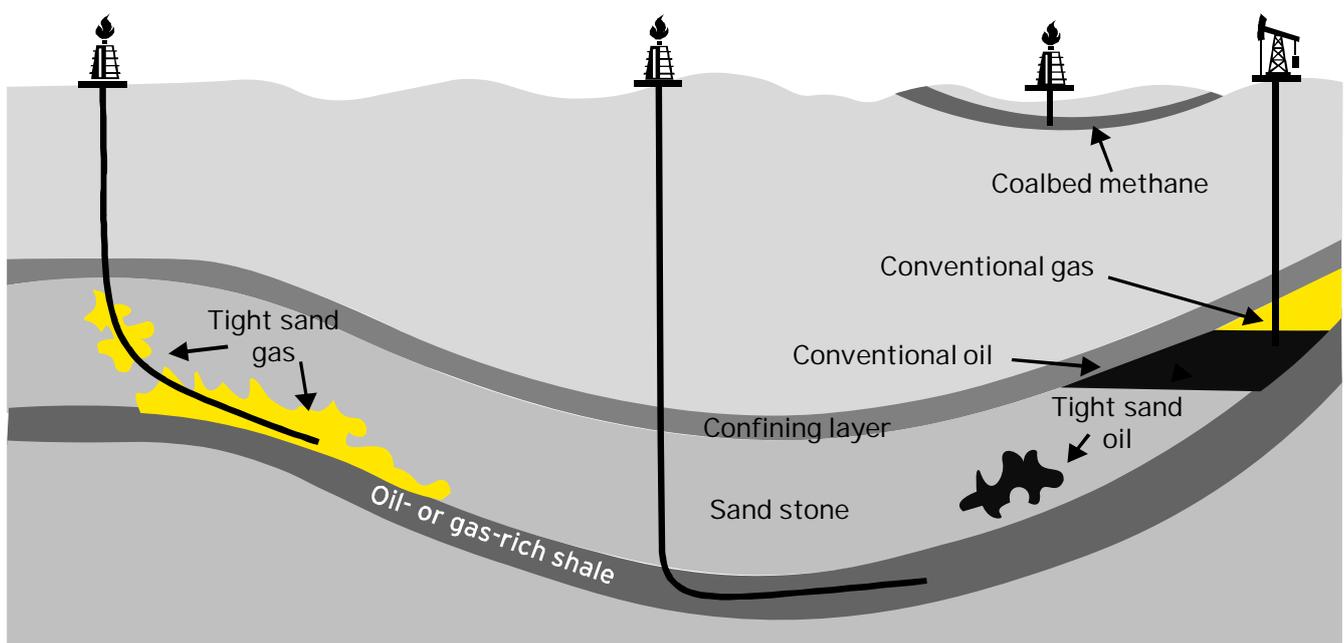
Tight Gas

Tight gas refers to natural gas trapped in extremely low permeable and low-porous rock, sandstone or limestone formations. Conventional extraction is made impossible due to the lower permeability of the reservoirs, which traps the gas in smaller pockets distributed throughout the strata of the field. To access the gas it is therefore necessary to apply fracking to crack open the rock, and allow the gas to escape into the wellhead.

Shale Gas

Shale gas refers to natural gas contained in organic-rich formations dominated by shale-stone. The characteristics of these formations are similar to those of tight gas, with low-permeability and porosity. Shale gas is therefore often considered a sub-category of tight gas, despite being the most common type of unconventional gas.

Figure 2.7 - Hydraulically fractured unconventional oil and gas and conventional oil and gas resources



2.2 Introduction to onshore hydraulic fracturing

The U.S. is the main producer of unconventional oil and gas extracted through hydraulic fracturing. Over 75% of global unconventional gas production occurs in the U.S.

Coalbed Methane (CBM)

Coalbed methane is the extraction of methane absorbed on the surface of coal within a coal seam formation, often relatively close to the ground. These formations stretch horizontally and are therefore often horizontally drilled, a process typically performed for most onshore fracked wells.

Light tight Oil

Light tight oil or tight oil is a term that can cause some confusion as it is also known as shale oil as it is often found in shale formations. It is not to be confused with kerogen oil, often referred to as oil shale, to due to the fact that light tight oil is a lighter oil that flows when fracked. Tight oil can also be found in sandstone and therefore the IEA recommends using the term light tight oil to avoid any confusion [1].

In contrast to conventional oil which is found in permeable basins, tight oil refers to oil that is trapped in formations that are not very porous, meaning that the oil cannot easily flow out into conventional wells. Instead, as with unconventional gas, the oil is accessed by drilling horizontally across the deposit and then fracking to crack open the rock to allow the oil to flow.

Whilst the IEA often differentiates between tight oil and shale oil, this study combines the two under tight oil due to the broad similarities [1].

2.2.3 Production, Reservoirs and Distributions

Assessing the reserves of unconventional oil and gas resources is considered more difficult than for conventional resources. This is due to uncertainty of

the volume of the reservoirs that can be connected to production wells as the rock formations are often heterogeneous and of low permeability. There are also large variations in estimates depending on sources, where more focused and individual area studies can show higher estimates. Multilateral organizations like the IEA are generally considered to present the more conservative estimates. The IEA will be used in this study as the main source of information on reserves and production numbers.

Hydraulically fractured gas

The IEA reported that the total production of unconventional gas (CBM, shale gas and tight gas) in 2014 was approximately 700 billion cubic meters (bcm), equal to about 20% of world supply [5]. Table 2.1 shows an overview of current production in the top producing countries which is dominated by the U.S. with 75% of the total production. Unconventional gas resources are estimated to account for approximately 44% of total technically recoverable gas resources [2] and are distributed across the regions of the world as can be seen in figure 2.8.

Tight Oil

Estimated technically recoverable global tight oil resources amount to 420 billion barrels (bb), approximately 10 % of total world oil according to IEA estimates [2]. Notably reserves are found in the U.S., Argentina, Russia, Australia, Chad, China and UAE.

Global tight oil production in 2016 was estimated by the US Energy Information Administration (EIA) to be 4,98 million barrels/day (mb/d), with the majority coming from the U.S, which constitutes about 5% of total global oil production [2].

Table 2.1 - Total unconventional gas production in 2014 by producing country

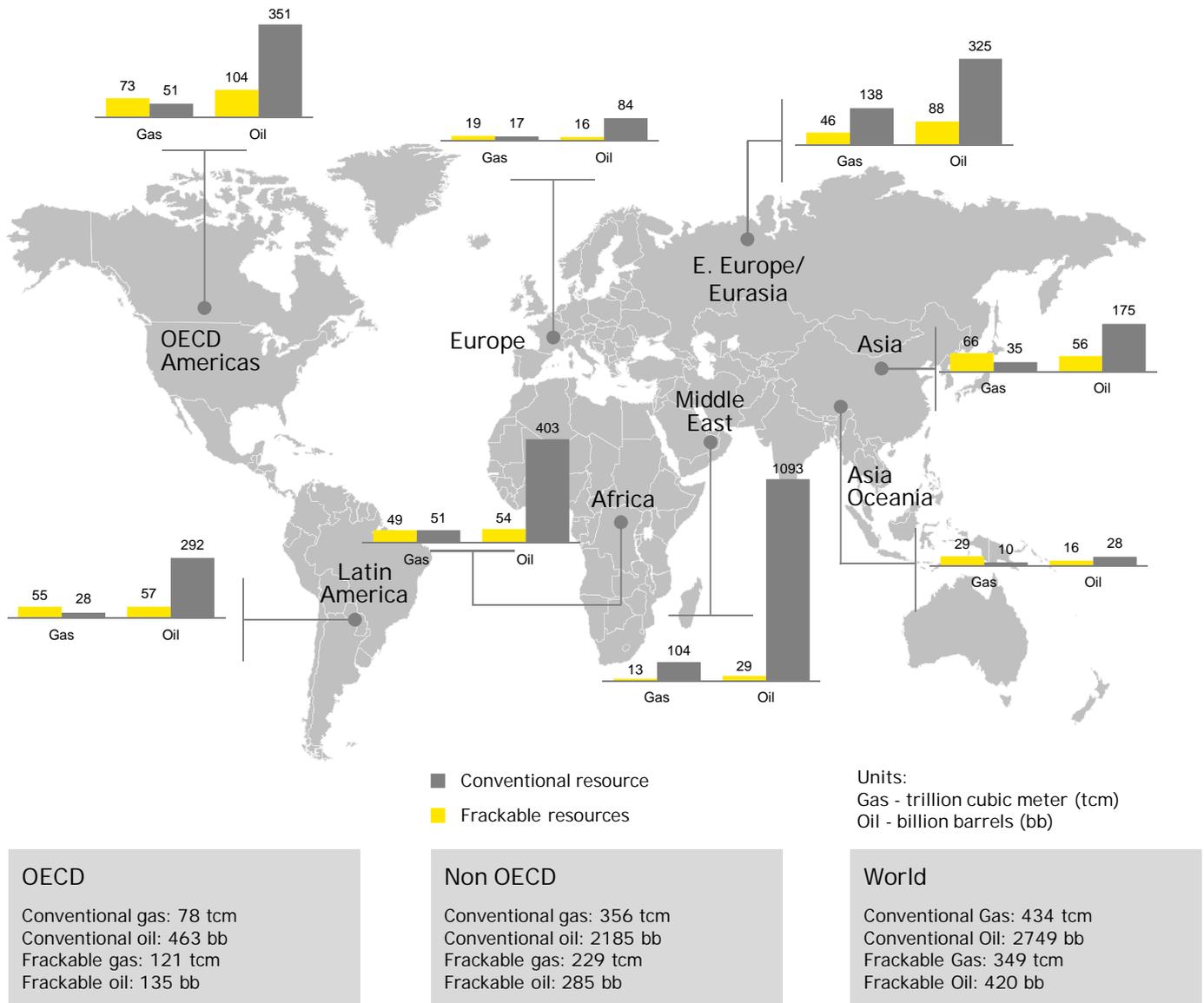
Country	CBM (bcm)	Shale Gas (bcm)	Tight Gas (bcm)	Total (bcm)
U.S.	37,10	378,77	127,71	543,58
Canada	7,18	5,94	72,93	86,04
China	14,10	1,32	17,22	32,64
Russia	0,50	-	20,77	21,27
Australia	7,65	0,00	0,00	7,65
Argentina	-	0,31	2,21	2,51
Germany	0,90	-	0,41	1,31
Egypt	-	-	1,02	1,02
United Kingdom	0,06	-	0,60	0,66
Mexico	-	-	0,61	0,61
Poland	0,27	0,00	0,34	0,61
India	0,53	-	0,01	0,53
Sum	68,28	386,33	243,82	698,42

Source: Adapted from IEA Unconventional Natural Gas Database [5]

2.2 Introduction to onshore hydraulic fracturing

The majority of hydraulic fracturing occurs in North America, but there are large resources in the rest of the world, particularly in Asia-Pacific where production is emerging

Figure 2.8 – Geographical distribution of oil and gas resources technically recoverable by conventional methods or fracking



Source: Adapted from IEA, World Energy Outlook 2016 [2]

2.3 Introduction to open mining

Open mining of oil-based hydrocarbon resources is comparable to open mining of other resources such as coal, with only small variations based on geology

2.3.1 Production Method

Open mining or open-pit mining is a surface mining technique for extracting several resources, such as rock or minerals, from relatively shallow or surface deposits. The technology used to excavate the ore is similar across the resources with variations dependent upon the geology (see figure 2.9). However the processing of the excavated ore differs depending on the resource that is being mined.

2.3.2 Unconventional hydrocarbon resources extracted through open mining

There are two main categories of unconventional oil that require open mining for extraction: oil sands and oil shale.

Oil Sands

What is most commonly referred to as oil sands is a mixture of sand, water, clay and bitumen. Bitumen is oil that is too heavy or thick to flow or be pumped without being diluted or heated. Oil sands are often also referred to as tar sands. Tar however can describe a variety of thick black organic substances. Thus, for clarity only the term oil sands will be used throughout this report.

There are two different methods of producing oil from the oil sands: open-pit mining and in situ (see chapter "2.3 Introduction to in situ production" for further details). Bitumen that is relatively close to the surface is mined, while bitumen that is deeper below ground level is produced in situ using specialized

extraction techniques (see figure 2.9). As the impact and characteristics of the two different extraction methods are different, this study will present findings for each production method separately.

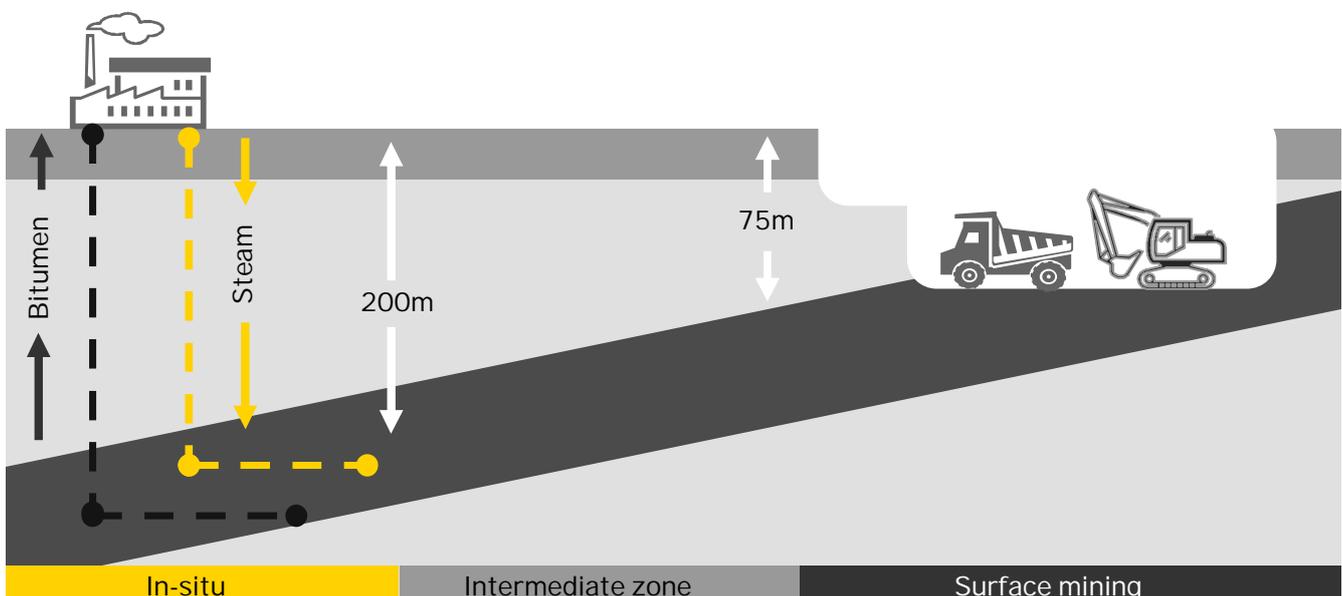
Open-pit mining of oil sands is similar to many coal mining operations. Large shovels scoop the oil sand into trucks that then take it to crushers where the large clumps of ore are broken down. This mixture is then thinned out with water and transported to a plant where the bitumen is separated from the other components and upgraded to create synthetic oil.

Oil Shale

Oil shale is not to be mistaken for shale oil, which is the more common form of produced unconventional oil (see chapter 2.2.2 -light tight oil). Oil shale is shale rock containing heavier, high viscosity oil in the form of kerogen, an organic chemical compound that make up a portion of organic matter in sedimentary rocks. See figure 2.10, for an overview of how reservoir and viscosity are used to separate the different types of oil resources.

There are two production methods that can be used to extract petroleum products from oil shale. One is to mine it as a solid rock and then heat it in a low-oxygen environment to extract usable oil and gas. The other production method is to heat the oil in situ, applying heat directly to the formation and then pumping out the resulting oil. In situ production is considered an experimental method, and is not yet commercially developed. In this study oil shale is therefore only considered as mined.

Figure 2.9 - Diagram of surface mining and in situ production



2.3 Introduction to open mining

Only 20% of oil sands are recoverable through open mining, however 45% of production currently comes from open mining operations

2.3.3 Production, Reservoirs and Distribution

Oil sands

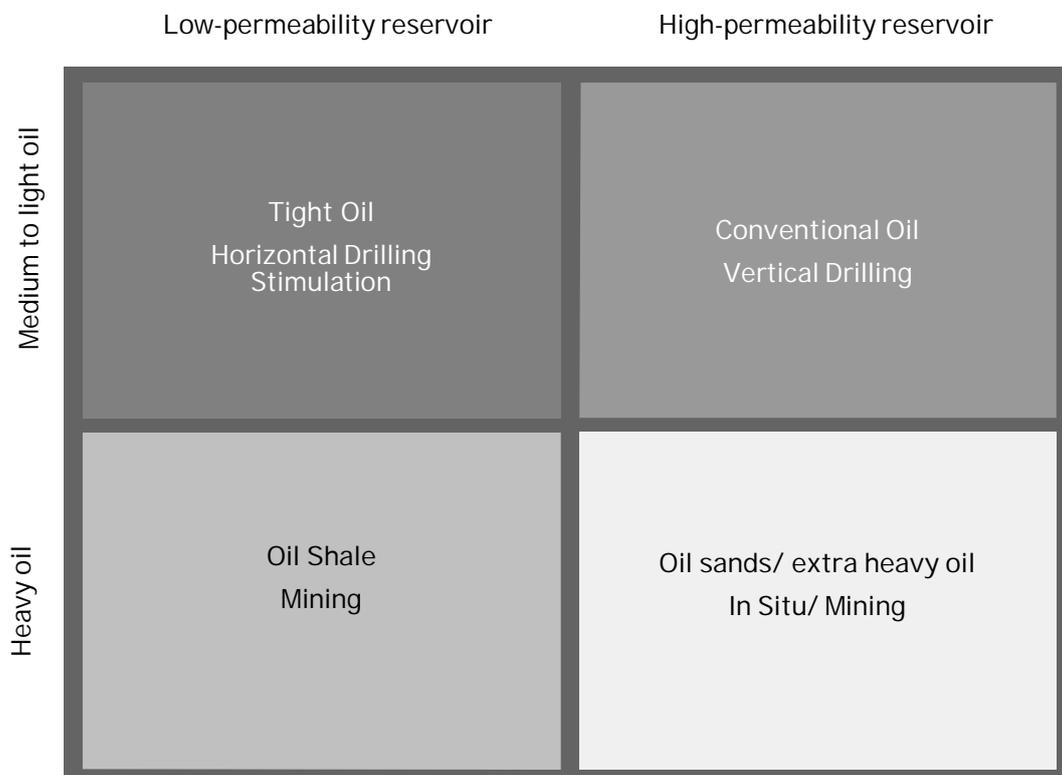
Open pit mining is sometimes misrepresented as the only method of utilizing oil sands. Just 20 per cent of the oil sands are technically recoverable through open mining. This is because it is generally uneconomical to excavate deeper than 75 meters into the ground, as the cost of removing the material covering the oil sand becomes too high (see figure 2.9) [6]. See figure 2.12 for an overview of the total technically recoverable oil sands resources.

Although most of the reserves are only accessible through in situ production, in 2016 45% of the total 2,4mb/d of oil that was produced from oil sands came from open mining [7].

Oil Shale

Historically, oil shale has been mined not only for conversion into oil, but also for power generation, cement production and for use in the chemicals industry. Mining of oil shale dates back to the 1830s and peaked in 1980 at 46 million tons per year (Mt/yr), falling to 16 Mt/yr in 2004 [1]. Around 80% of commercial oil shale is mined in Estonia, where it is used predominantly for power generation [1]. As can be observed in table 2.12 the total resources in Eastern Europe and Eurasia are relatively small, and production is not expected to increase substantially. The US and OECD Americas however have considerable kerogen oil resources, but the production today is small, and open mining is not considered as a favorable technology due to the massive land use. In situ is considered to be the most appropriate way of potentially extracting these resources, but further technological development is necessary for commercialization [1].

Figure 2.10 – Type of oil and resource and associated recovery technique



2.4 Introduction to in situ production

In situ is a production method that utilizes steam to extract viscous oil from reservoirs deeper than 200 meters

2.4.1 Production Method

In situ (Latin, meaning “in place”) is a production method for producing heavy oil and very heavy oil from reservoirs that are typically below 200 meters depth [6]. It is often utilized on the same reservoirs that are being open-mined, as open mining rarely excavates below 75 meters due to economical constraints of removing the material covering the oil sand. 200 meters is the general threshold for what is considered deep enough underground for in situ, as this reduces the risk of uncontrolled leaks of oil reaching the surface to an acceptable level. Thus, it is not possible to choose between using open mining or in situ operations on a given reservoir.

Advances in technology, such as directional/horizontal drilling, enable in situ operations to drill multiple wells (sometimes more than 20) from a single location, reducing the surface disturbance. The majority of in situ operations use steam-assisted gravity drainage (SAGD) [6]. This method involves pumping steam underground through a horizontal well to liquefy the bitumen that is then pumped to the surface through a second well (see figure 2.11).

A second technology called cyclic steam stimulation (CSS) is also used, based upon the same principles of using steam, but with vertical wells and cyclic use of steam [6]. This may be perceived as a less effective method that requires drilling of more wells compared

to SAGD, however it is the geology of the reservoir that determines which technology is most suitable.

2.4.2 Unconventional resources extracted through in situ production

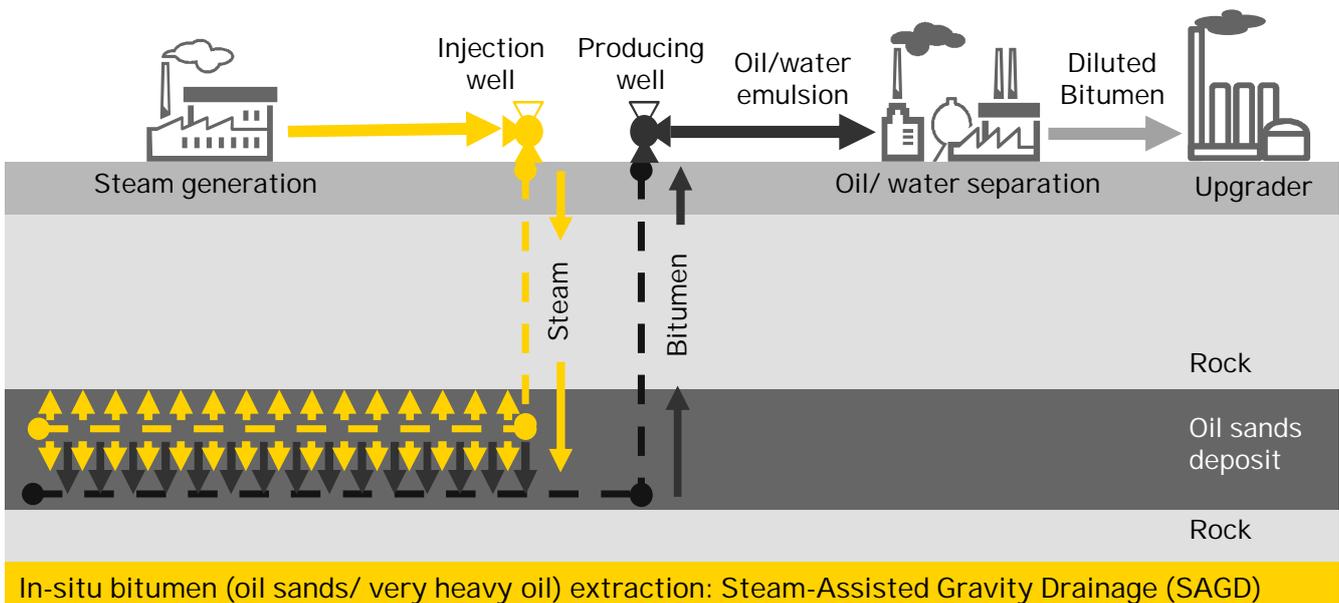
Oil Sands

About 80% of oil sands reserves are recoverable through in situ technology [6]. Many oil sands reservoirs utilize both in situ and open mining since the depth at which the resources are located may vary throughout the field [6].

Extra Heavy Oil

Extra heavy oil is comparable to oil sands, with the main difference being that it is less viscous (see figure 2.10). Unconventional extra heavy oils are mostly located in Venezuela, which contribute to giving it the world's largest oil reserves, above both Saudi Arabia and Canada [1]. Extra heavy oil follows the same production steps as oil sands, with extraction from the porous rock using steam to increase the temperature of the formation. This reduces the oil viscosity, allowing the oil to flow into the well and be extracted from the ground. It is not considered possible to extract the Venezuelan extra heavy oil through conventional mining, as the reservoirs are located too deep [1].

Figure 2.11 - Diagram of Steam-Assisted Gravity Drainage (SAGD) in situ production



2.4 Introduction to in situ production

The main production of oil sands and extra heavy oil occurs in Canada and Venezuela, but there are also large resources in Eastern Europe and Eurasia

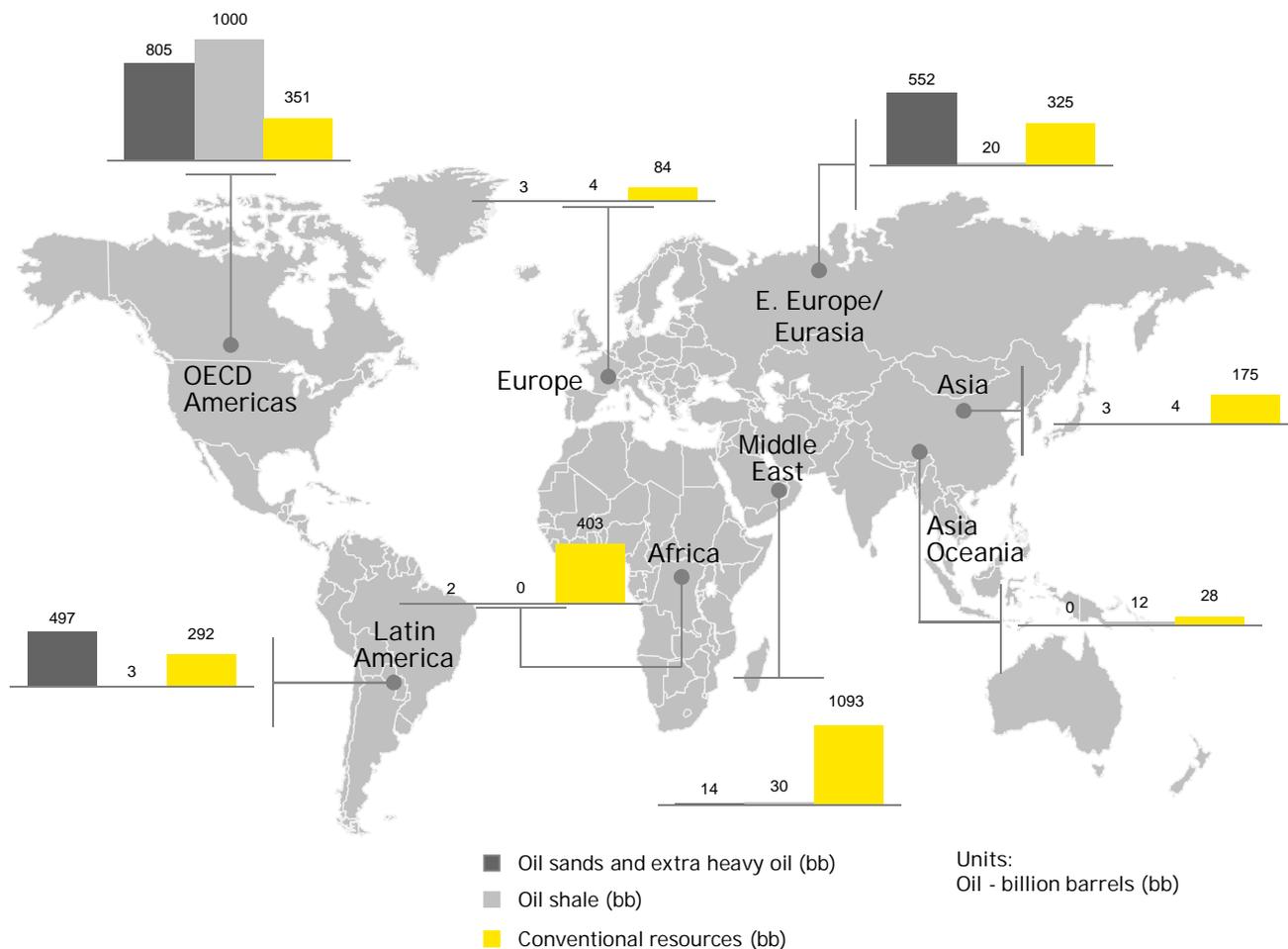
2.4.3 Production, Reservoirs and Distribution

Most in situ production currently takes place in Venezuela and Canada. About 55% of Canada's oil sands production of 2,4mb/d is produced in situ [7]. Venezuela's extra heavy oil field, the Orinoco Belt, is considered the largest oil field in the world in terms of total oil in place. In 2015 it produced 0,4mb/d extra heavy oil, roughly 15% of Venezuela's total oil production.

Figure 2.12 shows that the main recoverable oil sands reserves can be found in OECD Americas, mainly Canada. There are however also large extra heavy oil assets in Eastern Europe / Eurasia, and Latin America. There are also very large oil shale reserves in OECD Americas, but these are yet to be exploited on a large scale.

Altogether total technically recoverable resources of oil sands, extra heavy oil and oil shale are larger than conventional oil resources.

Figure 2.12 – Geographical distribution of conventional oil, oil sands and oil shale technically recoverable resources (unconventionals recoverable through mining or in situ production)



OECD
Conventional oil: 463 bb
Oil sands and extra heavy oil: 808 bb
Oil shale: 1016 bb

Non OECD
Conventional oil : 2186 bb
Oil sands and extra heavy oil: 1068 bb
Oil shale: 57 bb

World
Conventional oil: 2749 bb
Oil sands and extra heavy oil: 1876 bb
Oil shale: 1073 bb

Source: Adapted from IEA, World Energy Outlook 2016 [2]

2.5 Introduction to coal to liquid and gas to liquid

Coal and gas to liquid are energy intensive methods of producing synthetic crude oil from coal and natural gas

2.5.1 Production Method

Coal to liquid (CTL) is a process for converting coal into liquid fuels such as gasoline or diesel. This allows coal to be utilized as an alternative to crude oil.

The process starts with the coal being heated with oxygen and steam to create a synthetic gas or syngas, mainly consisting of CO and H₂. By using a process called Fischer-Tropsch it is possible to convert the syngas into a synthetic crude oil. Several other processes can also be used to convert the syngas, but the Fischer-Tropsch process is the most widely used technology to create liquid hydrocarbons. To create common fuels, the liquid hydrocarbons are run through a cracker to create longer chains of carbons that can be refined into diesel, naphtha or paraffin. The process to create these fuels is very energy intensive [2].

Gas to liquid (GTL) is another process that is similar to the CTL, except that the feedstock is methane rather than coal [2]. See figure 2.13 for further details on the CTL and GTL process.

GTL can be used as a solution for moving gas from markets with a surplus of energy to other markets where there is demand but gas pipelines are not in place. The process is however very energy intensive, and the technology competes with Liquefied Natural Gas (LNG) as a method for long distance transport.

2.5.2 Current Production

CTL and GTL are produced in small quantities relative to global oil production, and the technologies are still under development. The technologies are therefore considered only as viable solutions for niche markets [2].

CTL

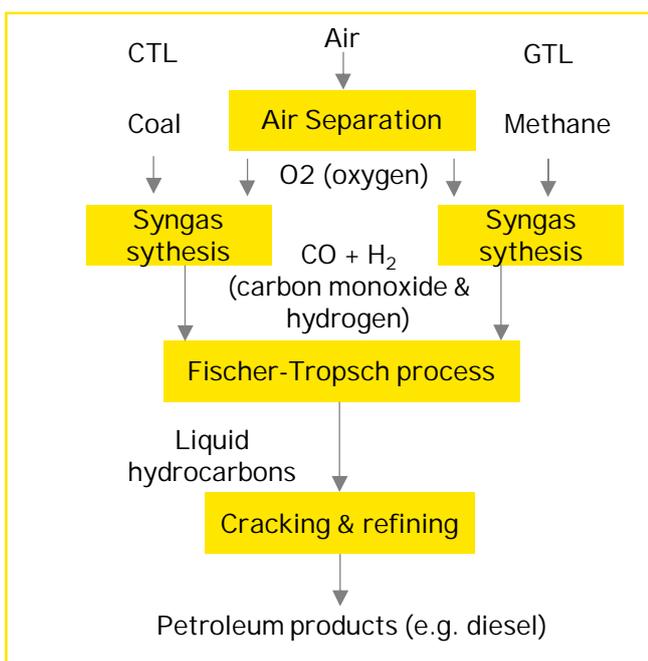
CTL is particularly attractive to countries that rely heavily on oil imports and have large domestic reserves of coal. South Africa has been producing coal-derived fuels since 1955 and has the largest commercial coal to liquids industry in operation today. Not only are CTL fuels used in cars and other vehicles, but South African energy company Sasol also has approval for CTL fuel to be used in commercial jets. Currently, around 30% of the country's gasoline and diesel consumed is produced from indigenous coal. The total capacity of the South African CTL operations stands in excess of 160 000 barrels per day (b/d) [8]. The US has been exploring the possibility of establishing CTL production though has no current plans for commercial production [8]. China and Mongolia are also developing the technology, with China having opened what is claimed to be the world's largest CTL plant in 2016 [9].

GTL

Small scale GTL is seen as an option to reduce gas flaring, where access to gas markets by pipeline is not available. The alternative technology would be Liquefied Natural Gas (LNG). LNG is a more developed technology, however the preferred choice of technology depends on several factors such as volumes, existing infrastructure and distance to a potential gas market. GTL can also be a viable option in situations where there is a desire to reduce the need for imported oil in a gas rich market. Several small scale pilots and commercial projects are under development in different regions, with Qatar currently having the biggest production plant in the world at 260 000 b/d [10].

Since there are varying technologies used in both GTL and CTL, production figures broken down on technology, as defined in this report and by the IEA, have not been identified. However, IEA estimates that the total production of oil by CTL, GTL and similar technologies constitutes approximately 0,3% of global oil production [2].

Figure 2.13 - CTL and GTL process description





3 Environmental Risks

Unconventional oil and gas has seen a rapid scaling up over the last decade. This has led to concerns over the environmental impacts associated with the new technologies that are used to enable production.

This chapter presents an overview of environmental risks, based on a review of available academic literature on the environmental impacts of the included unconventional fossil fuels.

3.1 Environmental risk framework

The study focuses on a set of environmental risk indicators, adapted from studies by AEA Technology [1] and AMEC Foster Wheeler (AMEC) [2,3], which have systematically recorded an exhaustive set of environmental risks possible for both unconventional and conventional fossil fuel extraction. The risk categories are as follows: water use and stress risk; surface water contamination; groundwater contamination; land use and degradation; air pollution; public health effects; climate gas emissions; seismicity.

Information on each category was gathered through a review of available literature for each unconventional technology included in the study.

For evaluating the risk potential for each category a risk framework is borrowed from King [4], where overall risk potential is estimated by weighting the environmental impacts as found in the literature review against two predefined criteria: consequence that is the amount of environmental damage potential (from slight to catastrophic) and their probability of occurrence (from extremely rare to highly likely) (see figure 3.1). This allows for a presentation of the findings in an objective manner that allow for comparison and ranking of impact risk across the different unconventional.

In some instances, studies were inconclusive, ambiguous, or faced with contradictory findings or arguments. In the event of single case studies, generalization across an entire industry with varying practice and regulation can also be problematic. This put limitations to the strength and applicability of any conclusions derived from the study. It should therefore be noted that the risk framework meant to give only an overview of potential environmental impacts. Conclusions or generalizations concerning any single operation should not be made, as not all circumstances can be known.

The majority of included studies are based on research conducted in the U.S. and Canada, where unconventional production is more mature and closer studied. Given the controversy and variety of views present in the discourse on unconventional fossil fuels, a degree of scrutiny is required in selecting sources. As a rule peer-reviewed studies make out the majority of the factual base of the study, supplemented in certain cases with other sources detailing specific events or details.

The studies by AEA and AMEC [1,2,3] are highly technical environmental impact studies for hydraulic fracturing, applying a version of the same general risk framework. These studies provide baseline references to aid the implementation of findings into the risk framework.

3.1 Environmental risk framework

The risk framework categorizes environmental impacts according to consequence and probability, allowing for an objective and generalized presentation of risk across different technologies and environmental impacts

To contextualize the environmental risks associated with unconventional a set of benchmark environmental risk ratings for their conventional counterparts is used.

The benchmark reference for conventional oil and gas is adapted from AMEC [3], allowing for a direct continuity and applicability of the framework. As the focus is predominantly on onshore unconventional the reference case reflects this, and does not include offshore activities.

The benchmark reference for coal is constructed from available academic literature following the framework. The primary focus is on mountaintop removal mining, which is considered to be comparable to oil sand open mining. This can cause: high risk of severe land impacts, degradation of surrounding biota, and contamination of both surface water and groundwater due to leakage, spillover from residual wastewater and mining residuals, which have a high risk of inflicting public health effects on surrounding population (based on literature reviewed in sources [5,6,7,8,9,10,11,12,13]).

For oil sands, open mining and oil sands in-situ production, no other previous risk assessment using the framework has been carried out. Therefore the risk ratings have been based on information from the literature reviewed. The risk ratings are calculated following the risk matrix, see figure 3.1, which has a reference scale for impacts provided by the AEA [1], and AMEC [2,3] studies.

The following risk categories have been used to define consequence (see figure 3.1):

- ▶ Slight – short term impacts with low severity. Direct impact on environment with noticeable effect, but limited and not causing widespread death to flora and fauna.
- ▶ Minor – incidents which will have an immediate and longer term effect (weeks/months) and take a number of months before the local environment is naturally recovered, or require a relatively minor physical intervention to remediate impact. Low severity, without widespread death to flora and fauna.
- ▶ Moderate – both immediate and longer term effect (months/year) but can be remediated with direct intervention within a number of weeks after the incident. Severity will still be low, although with along term impact.

- ▶ Major – both immediate and longer term effect (months/year) but can be remediated with direct intervention within a number of weeks after the incident. Severity of incidents will be widespread death of flora and fauna and significant impact on ecosystems and local populations.
- ▶ Catastrophic – immediate and prolonged effect on environment lasting several years. Severe effect causing widespread death to flora and fauna. Potentially irreversible effect to natural resources, requiring several years before environment return to pre-incident conditions.

The following risk categories have been used to define probability (see figure 3.1):

- ▶ Rare – incidents may have occurred within the industry previously but at a very low frequency.
- ▶ Occasional – these are incidents that should not occur under standard practices. These incidents will however be more common place, for example those that are known to have happened historically at several companies during operations.
- ▶ Likely – these are incidents which are likely to occur. The frequency of events is more difficult to predict, but should be assumed to have happened several times per year at different operating companies.
- ▶ Highly likely – these are incidents which are highly likely to occur. The frequency of events is more difficult to predict, but should be assumed to occur several times per year (or continuously) in each well location. Incidence of the issue is well documented within the industry with good practice guidelines warning of its potential.

3.1 Environmental risk framework

Greenhouse gas emissions for each unconventional will be measured and classified according to the emissions resulting from their extraction process

Figure 3.1 – Environmental Risk Classification

Probability classification	Consequence Classification					
	Slight	Minor	Moderate	Major	Catastrophic	No data
Rare	●	●	●	●	●	●
Occasional	●	●	●	●	●	●
Likely	●	●	●	●	●	●
Highly likely	●	●	●	●	●	●
No data	●	●	●	●	●	●

Legend – Risk Classification

● Low ● Moderate ● High ● Very high ● Not classifiable

Source: King, 2012 [1], AMEC 2015 [3]

Greenhouse Gas Emissions

Due to the characteristics of greenhouse gas (GHG) emissions it is not possible to rate GHG emissions with the same method as other environmental risks. This is because the risk of incident can be argued as equal for all technologies and resources as GHG emissions occurs continuously through operations and impact indirectly at a global scale. It will therefore follow its own methodology for assessment but nonetheless results have been included in the same risk matrix, see figure 3.3.

Since it is possible to measure and quantify the total emissions per unit of oil and gas produced, called well to tank emissions (WTT), this has been used as the basis for assessing GHG risk. The model uses conventional oil and gas - without enhanced recovery - as an emissions benchmark and allocates GHG emissions risk relative to this benchmark, with higher GHG emissions implying higher risk (see figure 3.2).

Figure 3.2 –GHG emissions classification chart

Risk category	Normalized difference from conventional oil in well to tank GHG emissions	Normalized difference from conventional gas in well to tank GHG emissions
●	- 10% and less	- 10% and less
●	- 10% to 10%	-10% to 10%
●	10 to 50%	10 to 50%
●	50% and more	50% and more

Legend – Risk Classification

● Low ● Moderate ● High ● Very high ● Not classifiable

3.2 Environmental risks - key findings

Figure 3.3 – Risk Matrix showing key findings by environmental risk and production technology

		GHG emissions (production well to tank)	Water use and stress risk	Surface water contamination risk	Ground-water contamination risk	Land use and degradation risk	Air pollution risk	Health effect risk	Seismic risk
Hydraulic fracturing	Shale gas	●	●	●	●	●	●	●	●
	Tight gas	●	●	●	●	●	●	●	●
	CBM	●	●	●	●	●	●	●	●
	Light tight oil	●	●	●	●	●	●	●	●
In situ	Oil sands / extra heavy oil	●	●	●	●	●	●	●	●
Open mining	Oil sands	●	●	●	●	●	●	●	●
	Oil shale	●	●	●	●	●	●	●	●
Conventional hydrocarbons	Coal	●	●	●	●	●	●	●	●
	Oil / Oil EOR*	●	●	●	●	●	●	●	●
	Gas	●	●	●	●	●	●	●	●
Other	CTL**	●	●	●	●	●	●	●	●
	GTL**	●	●	●	●	●	●	●	●

Legend – Risk Classification

● Low ● Moderate ● High ● Very high ● Not classifiable

* EOR is enhanced oil recovery which has higher GHG emissions than oil production without this technology

** The environmental risks from CTL and GTL are based on the respective feedstocks and only GHG emissions are technology specific and as such should be considered as indicators of minimum environmental impact

The environmental impacts of openly mined oil sands is overall comparable to surface mined coal

As apparent from the risk matrix, figure 3.3, only openly mined oil sands is comparable in overall environmental impact to the benchmark, surface mined coal. Coal has very high environmental risk in nearly all categories (described in section 3.1), except for water use, where it is exceeded by oil sands open mining.

Oil sands mining entails high or very high risk of significant impacts on land, water, air quality, public health and climate

Extraction of oil sands through open mining entails very high risk of widespread, irreversible impacts to surrounding landscapes and surface waters, due to incisions into large areas. Risk of air pollution levels are also considered very high, with oil sands operations found to be the single largest source of air pollution in

North America. This technique also contributes to significant GHG emissions through an energy intensive extraction process. Furthermore, oil sand mining is inherently highly water intensive, which entails high risk of water stress effects, exacerbated by the inability of current technology to recycle wastewater. There are also high risks of significant groundwater contamination as a result of wastewater leakage.

In situ oil sands mining has an overall lower impact than open mining, but risk of environmental impacts remain high

Despite lower water and land use than oil sands, the higher number of wells and growth potential of in situ lead to high risk of land degradation and water stress. The full consequences of in situ mined oil sands are not yet fully known. However, the current research indicates high potential risks of significant impacts on groundwater and surface water resources.

3.2 Environmental risks - key findings

GHG emissions from in situ and open mining of oil sands are significantly higher than conventional oil, with only CTL/GTL emitting more GHG

Extra heavy oil and oil sands have high GHG emissions with hidden challenges in byproducts

Extra heavy oil and oil sands have approximately 60-80% higher GHG emission in production compared to conventional oil, see figure 3.4. Furthermore, extra heavy oil and oil sand refining creates a byproduct called petcoke, a replacement for coal with higher GHG emissions during combustion than coal.

Hydraulic fracturing generally entails a high risk of impacts on local water and air quality, although with some differences between resources

Specifically shale and tight gas production can contribute to groundwater contamination through leakage of gas or fracking chemicals into aquifers. Leaks of chemicals and oil spills also contribute to contamination of surrounding streams and lakes.

The impacts are amplified by the large number of fracking operations. While operations are relatively small in size compared to oil sands open mining, they can cumulatively lead to high land impact and water use, as over 54% of wells are located in areas with high drought risk.

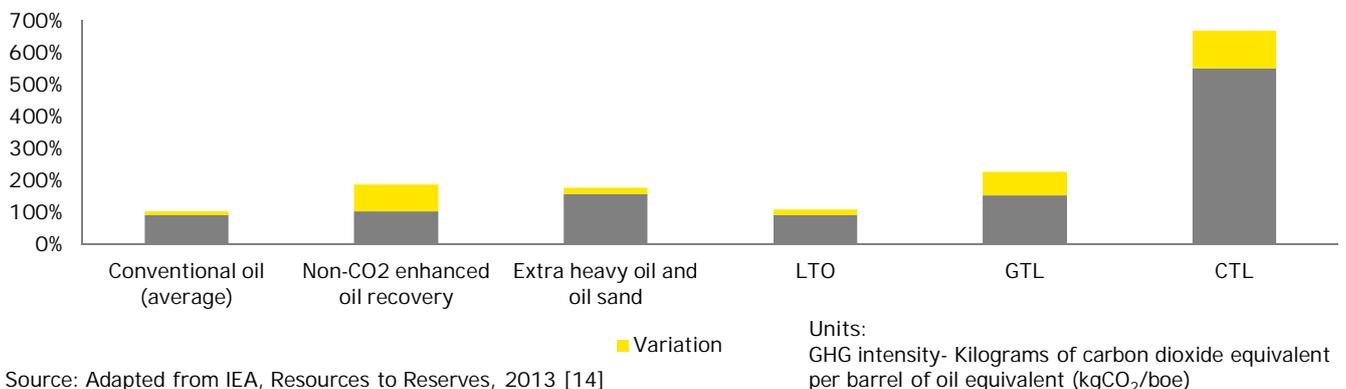
Use of hydraulic fracturing in production of unconventional gas has comparable GHG emissions to conventional natural gas

GHG emissions from production of unconventional gas, including shale gas, tight gas and coal bed methane, differ little from conventional gas on average, though limited global studies are currently available (see figure 3.5 for the U.S.). There are however differences from field to field and well to well. Well preparation can be a significant source of GHG emissions as well as the infrastructure to transport the gas to the market due to potential methane leakages.

CTL is the most carbon intensive with high overall environmental impacts similar to coal, the main input factor in the process

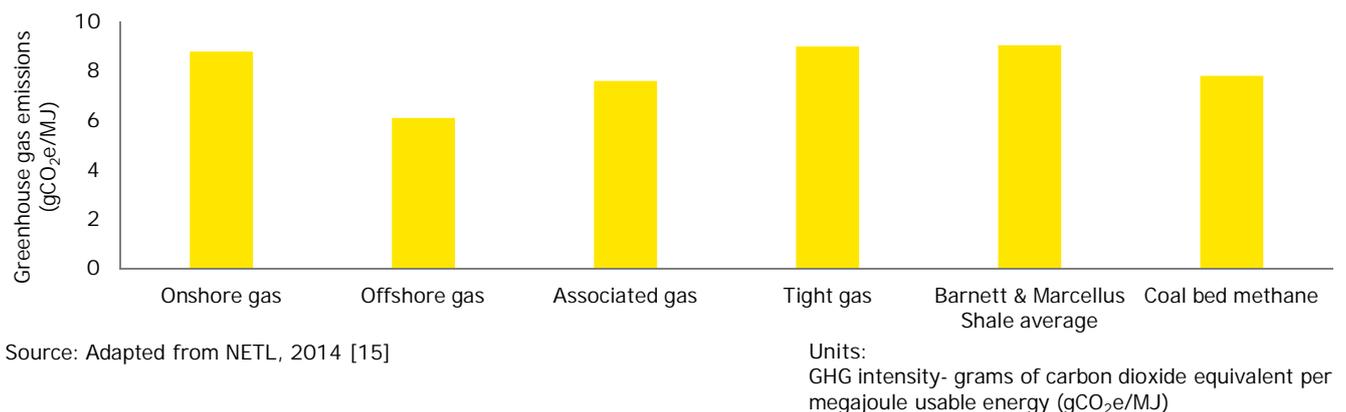
CTL can have GHG emissions six times that of conventional production, so high that emissions from production can be larger than from use of the fuel. Although gas can be considered a cleaner fuel than coal; GTL has approximately two times higher production emissions compared to conventional oil due to its energy intensive process.

Figure 3.4 - Well-to-tank (production) GHG emissions (normalized to conventional oil: 120 kg CO₂e/boe)



Source: Adapted from IEA, Resources to Reserves, 2013 [14]

Figure 3.5 - Upstream GHG emissions for different sources of natural gas in the U.S. (extraction, processing & transportation)



Source: Adapted from NETL, 2014 [15]

3.3 Environmental risks of hydraulic fracturing

The fracking process is highly intrusive with high risks of water contamination and pollution

		GHG emissions (production well to tank)	Water use and stress risk	Surface water contamination risk	Ground-water contamination risk	Land use and degradation risk	Air pollution risk	Health effect risk	Seismic risk
Hydraulic fracturing	Shale gas	●	●	●	●	●	●	●	●
	Tight gas	●	●	●	●	●	●	●	●
	CBM	●	●	●	●	●	●	●	●
	Light tight oil	●	●	●	●	●	●	●	●

Legend – Risk Classification

● Low ● Moderate ● High ● Very high ● Not classifiable

The process of hydraulic fracturing, also known as fracking, is common to shale gas, tight oil, tight gas and CBM. The basic nature of the environmental risks will therefore also be largely comparable, but with some differing characteristics which influence the overall risk assessments. Firstly the impacts common to fracking is presented, with sub chapters for each of the four individual resource types, the detailed risk assessment of each impacts can be seen in figure 3.7 on the following page.

Hydraulic fracturing involves significant water use with high risk of localized water stress

The fracking process relies on large quantities of water to be injected into the well, mixed with about 10% sand, and 2% various chemicals [3]. The water levels used for different plays vary depending on the formation and technique used, but is generally in the high range, comparable to the most water intensive conventional oil fields, using up to a total of 18 million liters of water for a single well [16].

Associated water stress and risk of depletion comes down to local conditions and the density of wells in an area. Fracking operations typically consist of several small plays, spread over several regions, leading to higher risk of localized water stress, particularly in western U.S. states.

A report by the environmental institute Ceres have developed a water risk framework, estimating that up to 54% of all fracking operations are located in areas with high or extreme drought risks, which can be further reinforced by high water consumption of fracking [17].

The technique involves high risk of groundwater contamination as toxic fracking water and fugitive gas can escape into groundwater resources

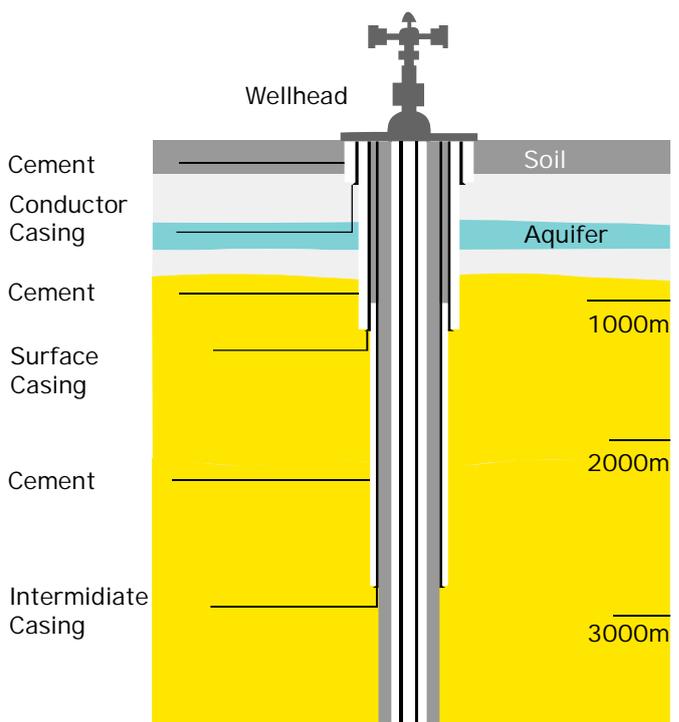
The fracking process involves cracking open rock formations using high pressure water. This process leads to cracks and fissures in the shale formations, that sometimes stretch out of field.

Terms and Expressions:

Well Casing

Figure 3.6 shows an outline of the fracking well casing designed to protect against leakages. Casing technology has been developed to add more layers around the well, but despite this the risk of casing failure remains.

Figure 3.6 – Fracking well casing

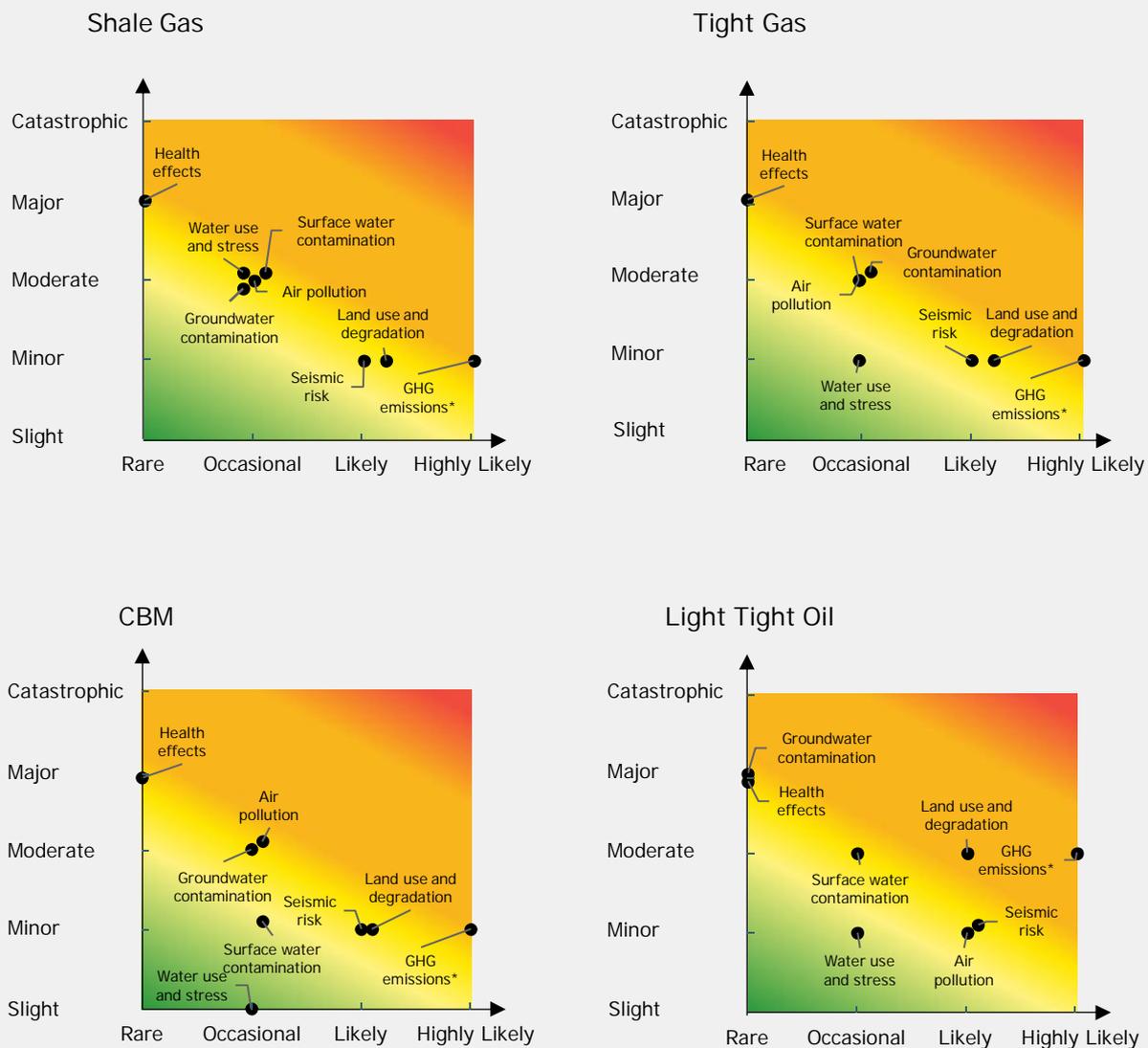


3.3 Environmental risks of hydraulic fracturing

The majority of environmental impacts for the fracking unconventionalals are assessed to have moderate to high consequences for surrounding nature

Figure 3.7: Detailed risk assessment of hydraulically fractured unconventional oil and gas

The graphs below give an in-depth perspective of the allocation of risk of consequence and probability for the different environmental categories.



* GHG emissions have been rated with a different system than the other environmental risks (see methodology in chapter 3). GHG emissions have therefore been rated with a "highly likely" occurrence risk, and allocated with the impact risk according to color rating.

3.3 Environmental risks of hydraulic fracturing

Large amounts of chemicals are used in the fracking process and can contribute to contamination of both surface and ground water resources

Toxic fracking fluids injected into wells can migrate along fractures created by the fracking process, potentially into nearby aquifers. Oil and gas released in the process are also able to escape along these fractures, particularly associated methane. Leaks can also come from gasket and casing failures, failures in the protective layer around a well designed to prevent leaks. Some estimate that this occurs for up to 3% of all fracked wells [18]. However, as no centralized data is collected for these incidents the exact number is hard to pinpoint. Although the probability may be moderate, the potential impact on humans and the environment is significant.

Methane leaks have received much attention due to the famous example where tap water is set on fire due to associated methane contamination. While the levels of methane in itself need to be quite high before being toxic to humans, it can still cause risks due to oxygen depletion in reservoirs, which again can lead to development of other toxins dangerous to human consumption. Methane leaks have also been connected to explosions of water wells and other nearby facilities.

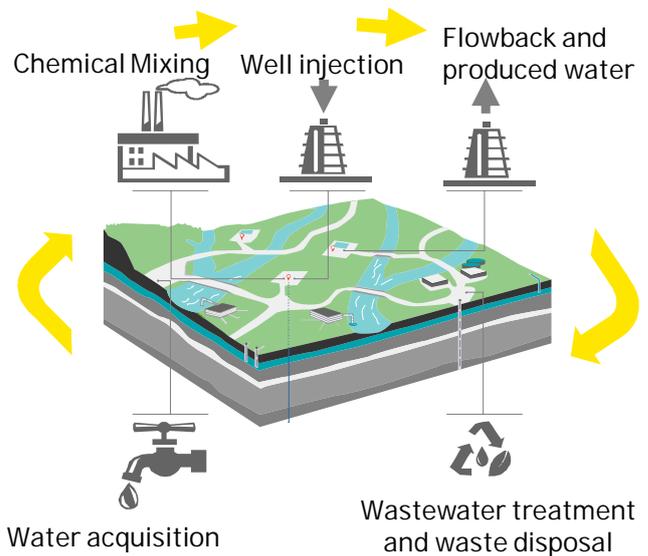
The evidence for methane and gas contamination is stronger than for contamination from wastewater, as it is easier to discover. The EPA has conducted a large survey concluding that methane leaks can be caused by fracking [19]. Again, the lack of pre-fracking data cast some doubts related to whether the gas migration came from natural causes. While recognizing the risk of methane leaks, the EPA's conclusion is moderate concerning the extent of the problem.

Independent studies also support the notion that fracking can induce methane contamination, with several documented cases [20,21,22]. As some of these leaks are from natural causes, it has been hard to pinpoint those caused by fracking. However, Vindic et. al [20] present evidence linking methane leak rates with gasket and well-casing failure rates, establishing a more definite causality between fracking and methane leaks [18]. Research has also shown that shallower fields have a bigger risk of contamination [23].

Evidence exists indicating water contamination traceable to fracking wastewater, but faces similar problems from lack of pre-fracking data on water quality. The EPA carried out a large study that found proof of contamination in certain deep groundwater resources. However, some parameters in the research lead to less confidence in the water-quality results, and the results were therefore debated

internally in the EPA, and contamination levels were declared as safe. The Federal Agency for Toxic Substances and Disease Registry has however contradicted the EPA, advising residents in the surveyed areas to take precautionary steps to reduce health risks from drinking water [24]. Furthermore, independent study revisiting the EPA results has presented the evidence as more conclusive, suggesting impacts might be wider than previously thought [25].

Figure 3.8 - The water cycle of hydraulic fracturing



Flowback water and fracking chemicals risk contaminating surrounding lakes and surface water streams

Fracking also entails high risk of contributing to surface water contamination. This risk mainly comes from spills and leakages of oil, flowback water, residuals or fracking chemicals to surrounding lakes, streams and water sources. There are also blowout risks and leakages from pipelines and transport [3,16].

The EPA has identified more than 1000 chemical additives; acids, bactericides, scale removers and friction-reducing agents used in different fracking operations. Many are found to be highly toxic and harmful to living organisms [16]. Figure 3.8 [5] shows the fracking water cycle. Here water is acquired from nearby sources before it is mixed with chemicals and injected into the well. Most operations seek to retrieve some of the water used, so called flowback, but the majority is still absorbed by the well rock formations and remains unaccounted for.

3.3 Environmental risks of hydraulic fracturing

The large scaling up of fracking activities contribute to high cumulative impacts on landscapes, water, air quality and even seismic activity

The amount of water retrieved will vary depending on the technology and the site, but estimates have been made for the percentage of flowback compared to fluid injected by AMEC [2]:

- ▶ Shale gas 0-75% (estimate 50%)
- ▶ Tight gas 17-35% (estimate 25%)
- ▶ Tight oil 10-60% (estimate 35%)
- ▶ CBM 61-82% (estimate 70%)

In addition to fracking chemicals, the flowback water contains large amounts of organic compounds from the underground deposit with a high degree of toxicity, making the handling of fracking water a critical concern. Where possible, flowback is injected into well deposits deep enough to minimize contamination risks. Otherwise, it is recycled for use in new wells in a process that creates a solid residual waste containing a range of toxins and low degrees of radioactivity, which also needs special deposits and handling. In some cases the water is treated for return to the general water system. Several studies have indicated that this has a high risk of contributing to surface water contamination, measuring high concentrations of pollutants traceable to fracking residuals [26,27].



Figure 3.9- Aerial view of Permian basin oil field

Image Source - Skytruth

The high number and location of fracking wells disturb nature on a large scale

Fracking involves installation of fracking well-pads, pipelines, and access roads. These incisions can have a harmful effect as they often extend into areas that have previously been untouched, upsetting natural environment and biodiversity.

Conventional oil & gas wells normally require up to 40 acres (0,2 km²), while horizontal fracking well development take around 160 acres (0,8 km²) per well. In addition, despite allowing for more wells per pad than conventional drilling, lower well life-time leads to an overall higher land use per unit produced. While well pads can be removed after abandonment, cemented decks are often left behind, causing longer term land degradation, see figure 3.9 for an extreme example from the Permian Basin in Texas [3].

Fracking operations may also lead to the spread of dirt, fracking residuals and other pollutants in a wide area of up to several hundred meters around the site. While the impact is minor, with a high number of fracking this risk will be cumulative, and therefore presents a moderate risk of land degradation [3, 28].

Fracking leaks contribute to severe air pollution with potential public health risks. Fracking operations may lead to air pollution as a result of uncaptured venting of gases and the release of volatile organic compounds (VOCs), as well as other emissions to air such as NO_x, SO_x, CO and PM during the fracking and production process. These chemicals contribute to acid rains and can contribute to potentially major public health effects. Air pollution is documented by a range of studies, some indicating extensive air pollution on regional level. However, the extent and concentration of air pollution is debated. The EPA still recognize it as a significant risk, and work to assess the overall systemic risk and regulatory framework [29,30,32].

The frequency of small earthquakes is rising due to the spread of fracking

Seismic activity is another much publicized impact connected to fracking. Induced seismicity is ground motion, or earthquakes, believed to be caused by human activities. Fracking can trigger this by injecting fluid into the ground, which can trigger seismicity from latent faults in the geological structure. While the fracking process itself can trigger seismicity the EPA has shown that the majority of cases are not associated with the actual fracking itself, but with drilling and injection of water into deeper water-disposal wells [29]. Such wells are used also for storing water from conventional oil and gas. But due to the high water use and larger number of wells associated with fracking operations, the risk of induced seismicity from fracking is considered higher than for conventional oil and gas.

3.3 Environmental risks of hydraulic fracturing

While impacts on water and air quality are higher, GHG emissions are comparable with conventional oil and gas

The EPA argues that the induced seismicity is not expected to be felt on surface levels. However, despite low risk for an individual fracking site, the massive scale of operations has led to a strong increase in registered cases of seismic activity felt by people. In certain cases the level has been expected to be significant, up to 5.7 on the Richter scale, causing damages to people and property [31]. The Pawnee tribal council currently has an ongoing lawsuit for damages caused by a nearby earthquake measured at 5.7, for which they claim a fracking company is to blame [32].

Pollution from fracking can cause adverse health effects for the local population and on-site personnel

While many of the pollutants and chemicals used in the fracking process can potentially impact human health there are still uncertainties as to whether fracking induced contamination is of such magnitude and extent that they actually have caused health degradation in local or regional communities.

Two large surveys exist. The first by Colorado School of public health, finds evidence that people living in proximity to the well pads may be at increased risk of several health impacts such as neurologic damage, developmental, endocrine system stress, respiratory health effects, as well as cancer and psychological stress. However, they caution against any definite conclusions due to the lack of cohort data and insight into longer term impacts [33].

The second, a University of Maryland study, establishes a range of health hazards connected to the air quality degradation and water contamination induced by fracking. While also pointing at missing data, they nonetheless conclude a high risk of public health impacts due to air quality contamination, and moderate for water contamination [34].

Lastly, there are also work related hazards associated with fracking. Personnel working on fracking sites are considered to be at higher risk of health issues due to proximity and continued exposure to fracking chemicals and products. Of particular concern is silica inhalation, a component of fracking sand, which has been found to potentially cause severe health effects, lung disease and cancer [34].

The literature on public health impacts does not contain enough detail to differentiate between the risks associated with the different types of fracking unconventional. While the overall risk drivers associated with surface water contamination and

air pollution does vary slightly, this does not provide sufficient basis for differentiation, hence the risk classification will be similar.

Greenhouse gas emissions are on par with conventional oil and gas

Hydraulic fracturing is relatively energy efficient compared to other unconventional hydrocarbon production techniques. For gas operations the majority of energy used during compression is associated with transportation of the gas. Overall GHG emissions do not differ greatly for tight gas, shale gas or CBM, and are similar to conventional natural gas production. Methane emissions are usually the largest contributors to GHG emissions, with variation occurring due to site specific factors such as flaring efficiency and leakage during natural gas transportation [15].

GHG emissions from tight oil are generally similar to conventional oil production, and below that of enhanced oil recovery without carbon capture [14]. This will also vary by site depending on well preparation as well as incidents of venting and emissions from hydrocarbon storage tanks.

Shale gas entails overall high environmental impact, which are exacerbated by the large number of wells on a typical site

Shale gas is the resource most researched and thus has more overall data available. Many fracking studies focus primarily on shale gas. In this study, shale gas therefore sets the benchmark for risks associated with fracking. The other fracking unconventional are then ranked according to supplementary information, based on their performance with regards to key risk drivers such as levels of water consumption, land use, and chemicals used, as well as to what extent they have markedly different characteristics.

Overall fracked shale gas has a high level for all the environmental impacts except GHG emissions. While shale gas has relatively small incisions in the ecosystem compared to an open mine, the high number of wells lead to overall high cumulative land use and degradation. This cumulative effect is central also to the risk evaluations for the other environmental impact categories. For instance, surface water contamination from leaks and spills, with runoff water and high amounts of wastewater is exacerbated by a high number of operations.

3.3 Environmental risks of hydraulic fracturing

The environmental risk levels are generally high for all the fracking unconventional, but tight oil and CBM present different risks

Individual wells have a low risk of casing failure and other defects that can contribute to gas leakage mitigation, but with such a high number of wells the impact potential increases in size and occurrence becomes more likely. Similarly, air pollution is worsened by development over large areas containing shale formations, making the impacts more regional than local. Water stress will also be more likely due to water being drawn from many local sources, increasing the probability of localized water depletion [1,3].

Tight gas is overall comparable to shale gas

The extraction of tight gas is largely comparable to that of shale gas in all categories, except for water use and stress, where the risk is considered less. This is because tight gas uses significantly less water due to the geological characteristics of the formations, reducing the potential for water stress issues. The reduced flowback water is however not sufficient to reduce surface water risk, which is considered equal to shale [3].

Tight oil entails higher risk of oil spills leading to potentially higher impact on surrounding nature and waters

Tight oil uses less water than shale gas, and therefore ranks lower in water use and stress risk. With less water use this also reduces the risks associated with water treatment and used water spills. However, production of oil leads to an additional risk connected to oil spills [3], which can

contribute to additional surface water contamination, giving it the same overall risk assessment for this environmental impact as for shale gas. For groundwater contamination however, risks are considered to be major as oil contamination will be more detrimental. Still, the overall risk is considered moderate, because the higher viscosity of oil makes it potentially harder for migration through underground fissures to nearby groundwater resources, reducing the probability and impact of leaks.

CBM is assessed to be less intrusive and widespread, but with high risks of groundwater contamination

Coal bed methane differs the most from the other fracking unconventional due to the nature of the reservoirs. With coal bed reservoirs generally located closer to the surface there are significantly higher risks of gas leakages in-field during the fracking process. However, CBM operations are significantly smaller in scale, with smaller well design, less casing and cementing, leading to lower land use and impact, with less cumulative impact due to more limited operations. Due to the reservoirs being closer to groundwater sources this provides an additional risk of groundwater contamination through fugitive gas. However, because of the porosity of coal formations less water is needed, reducing the overall potential for contamination through wastewater. The lower water use and smaller scale operations also reduce the overall surface water contamination risk [3].



3.4 Environmental risks of open mining

Open mining is most environmentally harmful of all the unconventional technologies

		GHG emissions (production well to tank)	Water use and stress risk	Surface water contamination risk	Ground-water contamination risk	Land use and degradation risk	Air pollution risk	Health effect risk	Seismic risk
Open mining	Oil sands	●	●	●	●	●	●	●	●
	Oil shale	●	●	●	●	●	●	●	●

Legend – Risk Classification

● Low ● Moderate ● High ● Very high ● Not classifiable

Of all the unconventional technologies surveyed by this study, open mining of oil sands comes closest to the risk levels of environmental impact for coal mining. Overall toxicity and residuals from oil sands mining have a high overall risk of systemic impact on water, biodiversity, and air quality, to the point where it also poses significant health risks for nearby populations.

Toxic wastewater and residuals entails very high risk of polluting streams and lakes

As described earlier, the open mining of oil sands requires large amounts of water. The most pressing concern resulting from the high water usage of open mining relates to contamination of surrounding groundwater or surface water. The Albertan energy regulator has found the water used for oil sands mining is of such toxicity that it cannot be recycled or brought back into normal water cycles [35]. Most operators therefore deposit the oil sand wastewater in large, open surface basins, so called tailing ponds. Despite regulations these tailing ponds have been found to have a high risk of leakage, and significant amounts of wastewater enter into nearby streams and rivers [36,37,38,39]. One study assessed that leakages from oil sands operations amounted to up to 3,6% of the total flow of the Muskeg river, an offshoot of the Athabasca river [36]. Such leaks contribute to water contamination from a range of toxins and heavy metals, and can cause widespread damage to the river ecosystems and aquatic life.

Groundwater resources are at risk of contamination Canadian federal studies have also established that wastewater can enter and contaminate nearby groundwater resources. These studies found high concentration of naphthenic acids, which are potentially toxic to living organisms [39]. This contamination is expected to come from runoff water from the open pits, as well as tailing ponds leakage. This area of environmental impact has received less attention than the more visible impacts connected to

surface water and land use. However, as the findings indicate there is a significant risk despite the limited information on the issue.

High water use can lead to local and potentially regional water stress

Oil sands mining consumes large amounts of water, with water intensity above the other unconventional. 5.2-7.7 liters of water is used per liter of oil extracted, higher than even the most water intensive conventional oil projects which range between 2.6-6.6 liters per liter of oil [40]. Most oil sands operations are located along the Albertan Athabasca river, which serves as the main water source for operations. Water stress has been recorded in the southern part of the river, where the Albertan regulator has stopped giving water permits to oil sands operations. In the northern part however, water resources are currently considered to be abundant with less risk of water stress [35,37].

However, as with shale gas, water stress can be more visible at the local level or under certain circumstances. The most alarming reports have warned that the concentrated water take from oil sands has amounted to as much as 25% of the total Athabasca river in periods with low water flow [41]. This has depleted the river in certain areas to the point that recreational vehicles are unable to travel the waterways, with potentially negative consequences for life in and around the river. Water use from oil sands can deplete or alter smaller streams and offshoots, contributing to localized droughts [37].

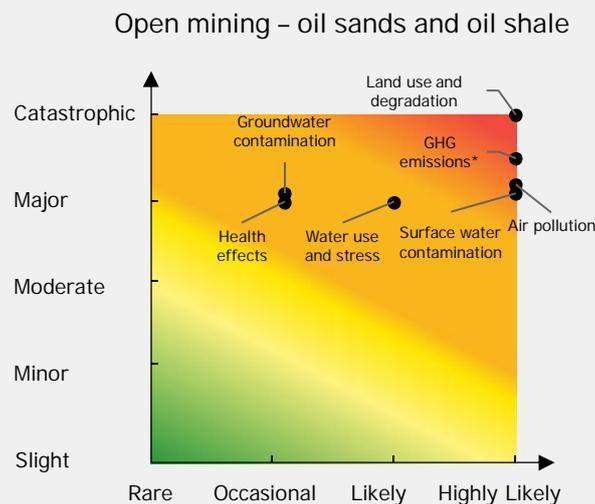
In the event of further expansions of oil sands operations the water stress risk will increase, and put significantly more pressure on the overall flow of the Athabasca river. Between 2000 and 2012 water use from oil sands increased by 88%, 9 times faster than the regional mean increase, with water use expected to at least triple by 2040 [37,39].

3.4 Environmental risks of open mining

Upgrading oil sands create residual petcoke which can be used as an extremely carbon intensive fuel, contributing further to the very high carbon footprint of oil sands

Figure 3.10: Detailed risk assessment of open mined oil resources

The graph below give an in-depth perspective of the allocation of risk of consequence and probability for the different environmental categories.



* GHG emissions have been rated with a different system than the other environmental risks (see methodology in chapter 3). GHG emissions have therefore been rated with a "highly likely" occurrence risk, and allocated with the impact risk according to color rating.

Although current research has focused most on local droughts, it is also considered that the consequences might be larger. Water stress impacts should therefore be considered as regional, and not only as isolated incidents. Furthermore, there is also suspicion that some of the water use might be masked, due to poor understanding of the interplay between groundwater and surface water in the region [37].

Opening mining causes irreversible damage to large areas of natural habitat

Oil sands activity commonly takes place in the Athabasca region of Alberta, Canada, home to much of Canada's Boreal forest and other sensitive biota, such as wet lands and peatlands. Open mining requires large incisions in surface area, with mining pits, residual storage and tailing ponds for water storage. It has been estimated that about 15% of forest covering concession lands have been cleared so far. In the event of a full scale up of oil sands activity over 8700 km² of forest could be cleared [40]. This puts oil sands in the top range of land-intensive fossil fuels. In addition there are also added impacts from associated upstream infrastructure

such as pipelines and upgrading plants, as well as transport and inroads [37]. The severity of land-use impact is considered to be major. Due to the sensitivity of the biota much of the impact is expected to be irreversible. While mining pits can be filled to a certain degree, open mining will degrade to the point where the original vegetation cannot regrow [42]. There is also high risk of extensive damage to surrounding wildlife. Studies have recorded widespread death of birds, bears and other animals, due to loss of habitat, poisoning, or through intentional killings after coming in contact with operations [36].

The oil sands industry is considered the leading source of air pollution in North America

Oil sands operations cause air pollution due to dusting up from open spaces or residual storages, vaporization from tailing ponds, or smog from upgrading processes. Certain studies have indicated localized to regional air pollution, particularly coming from NO_x, sulfides and volatile organic compounds (VOCs), with suspicion of wider impacts [35,36,43]. This is supported by a recent study in the journal Nature, showing oil sands as the leading source of air

3.4 Environmental risks of open mining

The impact of oil shale mining is comparable to oil sands, with very high risks of environmental impacts in the majority of categories.

pollution in North America, exceeding air pollution levels from any other source. The ranges of air pollution levels recorded are comparable to those of the largest Canadian cities. The recorded impact is particularly linked to the spread of secondary organic aerosols, which are associated with a range of severe health effects. Previously, the atmospheric spread of these was poorly understood. However, using new aerial methods such as drones and small aircraft, researchers have managed to record and trace their regional spread in the atmosphere [44].

Severe health issues in neighboring communities might be caused by oil sands operations

Many reports are made of public health degradation and elevated cancer rates in nearby communities, particularly in native communities. Much evidence remains circumstantial consisting of elevated frequency of certain cancer rates and other negative health indicators [35,36,46]. As with shale gas, these reports are indicative, but do not in themselves establish causality due to the same limitations regarding lack of historic data. However, a report by the Albertan Energy regulator establishes a direct link of public health degradation to the activities of a nearby oil sands mining operation [46]. The consensus is nonetheless that more overall evidence is needed, but given the evidence and the severity of the impact the overall risk assessment remains high.

Upgrading of oil sands is energy intensive and contribute to high GHG emissions

According to the IEA, GHG emissions from the production of oil sands (well to tank) are over 50% higher than using conventional production [17]. Open mining requires large amounts of energy (oil) to power the machinery for earth moving and mining, while the loss of forest and other land use change also contribute significantly to the climate impact. Land-use-change GHG emissions are estimated to be 5-60 kilograms of carbon dioxide equivalent per barrel of oil equivalent (kgCO₂e/boe) [47].

Upgrading oil sands to usable oil is an energy intensive process that normally consumes natural gas during hydrogenation, a process to improve the hydrogen to carbon ratio of the fuel. Coking is often also employed to remove carbon from the fuel to achieve the same affect. Coking generates petroleum coke (petcoke). The residual petcoke is then often sold to be used in iron and aluminum production if pure, or burnt as a substitute for coal if of lower purity. Burning petcoke releases 15% more GHG than coal on an energy basis and has similar air quality

impacts. It can also be cheaper than coal and hence indirectly support continued coal power generation. Petcoke is generally not included in the lifecycle GHG emissions calculations, and therefore represents an additional increase in addition to the reported lifetime emissions from oil sands liquid fuels when burned [48].

Oil shale open mining development is challenged by high environmental risks

The environmental impact of oil shale is considered to be mainly similar to oil sands though, as oil shale is only marginally developed at a commercial scale, there are fewer studies monitoring environmental impacts. However, as both rely on the same general techniques the potential environmental impacts can be considered quite similar, as demonstrated in an initial impact assessment by the Rand institute [49].

If further developed, land use will be particularly controversial, given the location of resources in more populated areas in Colorado and Wyoming, used for farming, grazing and overall recreational activities.

These areas are also home to several endangered species (including the U.S. national symbol the Bald Eagle). Otherwise there are risks associated with air pollution, water quality and public health, which are ranked at the same risk level as oil sands due to the large similarities in impact type [49].

Oil shale has a large climate footprint

Furthermore, burning oil shale for electricity releases GHG emissions that can be greater than coal, due to low efficiency and high carbon content. Estonia due to its reliance on oil shale for electricity generation is currently the OECD's most carbon intensive economy. This also have negative consequences for public health, where the low air quality in oil shale mining areas causes a range of associated respiratory diseases [50].

3.5 Environmental impacts of in situ production

Despite being less intrusive than open mining, impacts from in situ oil sands remain high

		GHG emissions (production well to tank)	Water use and stress risk	Surface water contamination risk	Ground-water contamination risk	Land use and degradation risk	Air pollution risk	Health effect risk	Seismic risk
In situ	Oil sands / extra heavy oil								
Legend – Risk Classification									
	Low		Moderate		High		Very high		Not classifiable

In situ environmental risks are less established than for other unconventional due to the lack of research available. For instance, some major incidents have been recorded, such as the Primrose bitumen leak, where 12 000 barrels of bitumen and water has risen from giant cracks in the forest floor, contaminating land and water. Excessive steam use was found to have caused the incidents. The Albertan Energy Regulator is working on regulation to contain the issue, and to establish whether this is an isolated incident or represents a generic issue for the industry as a whole [51].

However, some impacts have been systematically recorded and researched, with the predominant risks identified as groundwater contamination and public health impacts.

In situ production is highly energy intensive with high levels of GHG emissions

According to the IEA, the GHG emissions from producing fuel from in situ oil sands is over 50% higher than from conventional oil [14]. In situ production requires large volumes of energy, normally in the form of burning natural gas, to produce the steam required to extract the oil, emitting CO₂ in the process. This means in situ production produces in the order of 30 kgCO₂e/boe more emissions than mining of oil sands [14]. In certain cases bitumen is burned directly to produce steam, replacing natural gas, leading to even higher carbon emissions.

In situ operations disturb large areas through high number of sites and entry roads

Extraction through in situ requires significantly less landed area than open mining, and is in this aspect more comparable to fracking. However, in situ requires many well pads and associated infrastructure, causing damage to surrounding biota [37]. The expansion of sites is more sprawled than for oil sands open mining, leading to more roads and entryways, giving it the potential to expand over a larger area, hence an overall high cumulative impact [40]. The long term impact of in situ well

development is also largely unknown, and as indicated initially by the Primrose case mentioned above, there are concerns over the potential environmental impact of large scale steam injection into ground strata and its impact on soil quality [52].

Although most studies center on Albertan cases, concerns have also been raised about the potential impacts of heavy oil extraction in Venezuela's Orinoco belt region, home to dense rainforest and a river delta full of endangered species [53]. However, heavy oil production is still limited, and few studies have properly assessed the risks. Nonetheless, since the extraction of heavy oil relies largely on the same processes as in-situ extraction of oil sands, it can be assumed that many of the same risks are applicable [54].

Groundwater impact might be bigger than expected

In situ operations inject water into the ground at deep levels, which poses significant risk of groundwater contamination. Since in-situ techniques are newer than opening mining there are less studies documenting this risk. Some claims have been that in situ methods prevent contamination risks. However, one study published by the University of Ottawa in 2016 has found alarming indication of toxic chemicals from in situ production in nearby lakes. This has prompted Albertan authorities to investigate contamination risks connected with in situ more closely [55].

Despite lower water use than open mining, localized water stress concerns remain

In situ production uses roughly three quarters as much water as open mining, and does not require large tailing ponds as recovered water can be re-used for other production [5, 39]. Water use is comparable to that of shale gas, and is higher than conventional oil and gas production. The cumulative impact potential is also larger than for openly mined oil sands. In the event of large scale expansion of in situ production there will be higher risks for localized water stress over a larger area [40].

3.5 Environmental impacts of in situ production

Greenhouse gas emissions remain the biggest impact of in situ production, which has less risks of water and air pollution than open mining

Contained operations lead to lower risk of surface water contamination

Much like for fracking, operations in situ will carry with it risks for surface water contamination due to leaks, spills and flow off water from operating sites entering into streams. While recycling limits some potential for surface water contamination, the overall treatment and handling of wastewater still presents environmental risks. Similar to shale there is water runoff and spillage of chemicals and products associated with the process, which have a high risk of entering into nearby water streams.

Air pollution is limited compared to open mining operations

Oil sands in situ production does not produce the same extent of air pollution in the extraction process. Less heavy machinery, exposed mining areas,

residuals etc. will be associated with in situ well developments, limiting air pollution. However, there are comparable risks connected to upgrading and refining of extracted bitumen resources, leading to an overall moderate risk assessment.

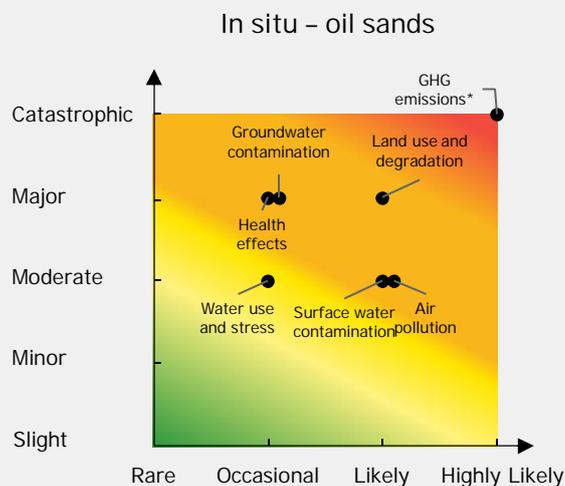
Extent of public health impact still uncertain

Public health risk studies do not separate in situ and open mining. In part, this relates to the fact that often these operations coincide, making it harder to attribute the recorded public health effects to either one of the production methods.

Given the risk profile of in situ the overall water contamination and air pollution is likely to contribute to some of the same public health risks as open mining, albeit at a smaller scale.

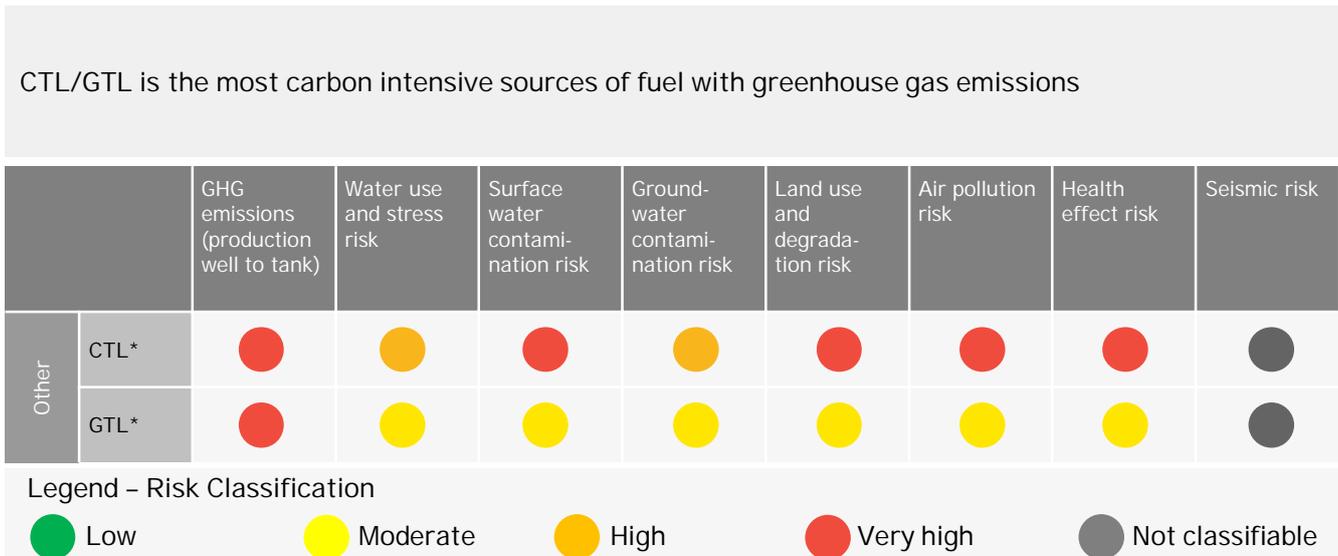
Figure 3.11: Detailed risk assessment of in situ oil sands

The graph below gives an in-depth perspective of the allocation of risk of consequence and probability for the different environmental categories.



* GHG emissions have been rated with a different system than the other environmental risks (see methodology in chapter 3). GHG emissions have therefore been rated with a "highly likely" occurrence risk, and allocated with the impact risk according to color rating.

3.6 Environmental impacts of CTL/GTL



* The environmental risks from CTL and GTL are based on the respective feedstocks and only GHG emissions are technology specific and as such should be considered as indicators of minimum environmental impact

Converting coal or gas resources is very cost inefficient and extremely energy intensive compared to extracting the oil from natural sources. It has largely been used in special cases of shortages or kept as a military reserve option during wartime. Markets are therefore niche, with limited commercial applicability [56].

Environmental impacts of CTL/GTL depend on primary resource input

GTL and CTL are industrial processes, generally utilizing the Fischer-Tropsch process to convert coal or natural gas resources into liquid synfuel usable for transportation. These fuels have a threefold impact through; extraction of the primary resource, liquefaction processing, and end-consumption. Hence, one can add the impact from coal, or from conventional or unconventional gas to the overall environmental balance sheet of GTL and CTL.

Coal to Liquid has the environmental impacts associated with coal mining

The environmental impact of CTL is set as the same baseline as coal production. The actual process of converting coal into liquid presents additional environmental risks due to the handling and processing of coal: residuals and solid waste disposal, high water consumption; wastewater discharge handling and storage; moderate air pollution with emissions of NO_x, SO₂ and particulates; moderate land degradation of surrounding areas, acidic rain and wildlife disturbances [56, 57]. The liquefaction process has similar impacts to a power plant that consumes the resources used, and is heavily dependent on emissions control technologies to limit air pollution. CTL plants also consume large volumes of water similar to coal power plants.

Gas to Liquid impact depends on what gas is used

GTL has less environmental impact associated with the conversion process itself. It has therefore been ranked at the same risk as conventional natural gas, except for on carbon emissions where there are significant differences [58]. This technology is yet to be widely deployed so the actual impacts could vary widely, although much of the impact is likely to occur during the extraction of the gas used as feedstock.

Conversion from solid to liquid fuel is extremely energy intensive

This involves reacting synthesis gas (syngas) which is a blend of hydrogen and carbon monoxide to produce hydrocarbon chains of the desired length to form synthetic crude (syncrude). With CTL the syngas is generated by gasifying the coal. This requires multiples steps and is very energy intensive and results in the release of carbon dioxide as the coal is broken down. The GHG emissions associated with making syncrude from coal are usually larger than the GHG emissions from burning the syncrude and are in the order of 6 times larger than those from producing conventional oil.

In GTL, methane from natural gas is partially oxidized to produce the syngas which is then converted to the syncrude. This has much lower GHG emissions than CTL, due to water being the byproduct rather than carbon dioxide, as well as having lower energy requirements. The process though still emits roughly double the GHG emissions to produce oil when compared to conventional production, see figure 3.4 [14].



4 Market outlook

The economic outlook for the various unconventional oil & gas resources is essential when considering their overall viability as fuel sources and their long term role in the world's energy mix. A clear understanding of the economic outlook of unconventional fossil fuels will also contextualize the debate on their viability under a carbon budget corresponding to the global 2°C climate goal.

Modelling of the world energy market has large uncertainties and cannot predict so called "black swan" events: sudden shocks in either supply or demand that can alter the market landscape overnight. Still there are some market fundamentals that can be used to define pathways based on current circumstances. Short term upstream infrastructure, production capacity and demand projections are more predictable, whilst policies by important organizations such as OPEC or potential climate legislation are more challenging to account for. However, a long term outlook must consider these factors, which are therefore considered across a variety of potential scenarios.

This chapter on market outlook examines both the more immediate short term energy market and the outlook for relevant unconventional fossil fuels. It will then delve further into scenarios providing long term outlooks. The IEA New Policy Scenario has been chosen as the scenario to describe a benchmark

Development [1]. This is considered by the IEA as their baseline scenario, as it takes into account broad policy commitments and plans that have been announced by different countries. This includes national goals to reduce GHG emissions and plans to phase out fossil energy subsidies, even if the measures to implement these commitments have yet to be identified or announced [2].

However, it is worth noting that the IEA is considered by many to be conservative in their predictions regarding the development of many low carbon technologies, which have the potential to reduce demand for fossil fuels. The IEA has in the last decade heavily underestimated renewable deployment levels and has been overly optimistic about fossil fuel demand developments. The IEA is also very optimistic that carbon capture and storage (CCS) will be a competitive technology that will significantly reduce GHG emissions. This raises their projections for continued demand for fossil fuels, despite there having been little progress in deployment of commercial scale CCS in recent years.

Alternative scenarios to the New Policies Scenario will be discussed in chapter 5. These take into account the potential for more dramatic long term changes, in particular with regards to actions to mitigate GHG emissions to combat climate change.

4.1 Market outlook – key findings

Unconventional Oil and Gas plays an important role in IEA’s benchmark scenario, the New Policies Scenario, although scenarios more optimistic in terms of climate action and use of fossil free technologies sees less significant development (as further discussed in chapter 5)

The current lower fossil fuel price environment is expected to continue in the short term, leading to an uncertain development for unconventional oil and gas

The development of unconventional oil and gas, and especially tight oil, tight gas and shale gas, are one of several factors that led to the sudden oil price drop in 2014. Light tight oil & shale or tight gas have survived in this new lower price environment due to rapid cost cutting, and reduced break even prices. The drivers behind the cost reduction are however considered somewhat temporary, based upon re-fracking of existing wells and completion of previously drilled wells in addition to use of existing infrastructure and less long term investment. See figure 4.1 for comparison of the estimated break even costs of different oil production methods in 2020, from Rystad Energy, which provides an overview of how costs may develop in the short term. This shows that oil sands and extra heavy oil especially struggle with the current sales prices as a result of high break even prices. In a short term perspective, further development of unconventional oil and gas is dependent on continued technological development to reduce break even prices, or an increase in oil and gas prices.

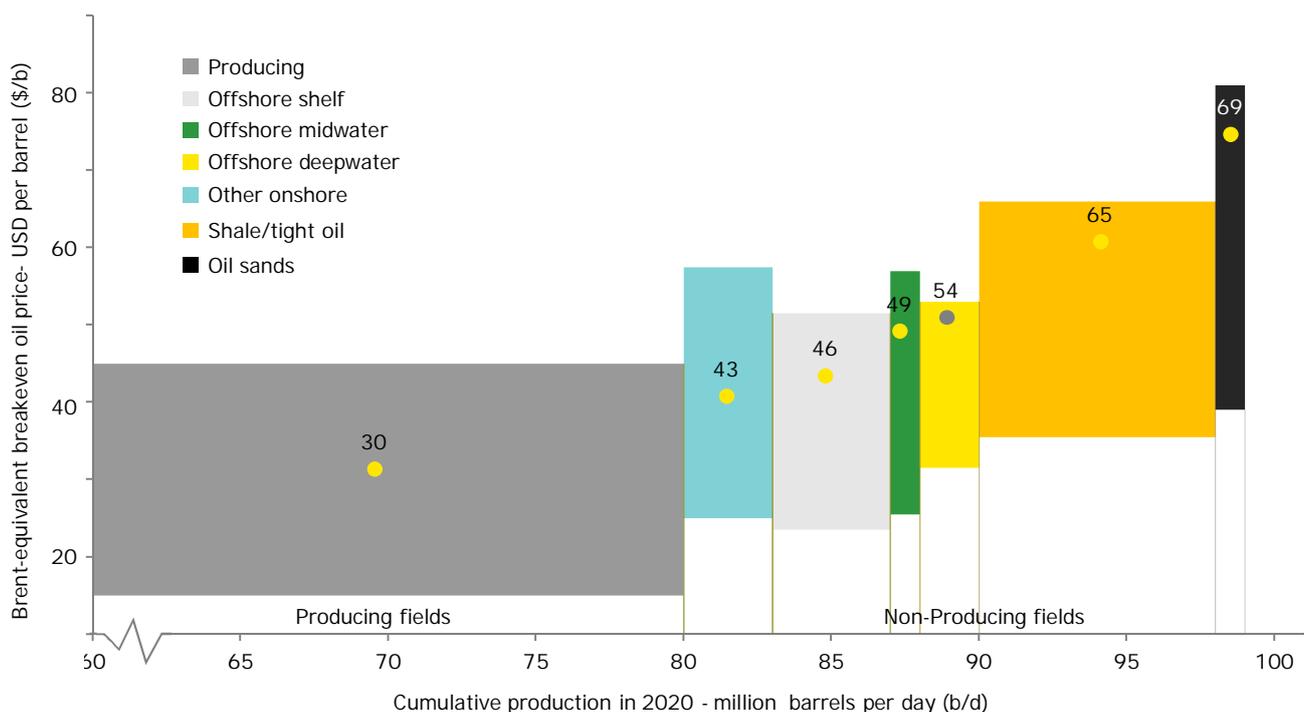
Global oil demand is not expected to peak until 2040, with room for further development of unconventional oil and gas

In the IEA New Policies Scenario, which predicts moderate climate action, prices are expected to increase, with geographical changes in global oil and gas demand. Emerging markets such as India and China will lead the demand increase with a reduced coal dependency and increased reliance on gas and renewable energy, while the US develops unconventional oil and gas further to become self-supplied in energy by 2040. US tight oil, Canadian oil sands, and some Venezuelan extra heavy oil will be the main sources of unconventional oil.

Gas markets will be more globalized with further development of LNG, and gas will be the fastest growing fossil fuel with increasing global energy demand

According to IEA’s New Policies Scenario, LNG is expected to continue to open the world gas market, leading to increased availability and prices. This will allow further development of shale gas, tight gas and coal bed methane in both existing markets and new markets.

Figure 4.1: Estimated break even cost of different sources of oil production in 2020 (Data from 2016)



Source: Adapted from Rystad Energy [3]

4.2 Short term oil market outlook

Unconventional oil has contributed to large changes in the energy market, particularly with the rise of U.S. tight oil production

Unconventional oil is considered one of the reasons for the 2014 oil market crash

In 2014, world oil prices plunged from peak levels well over \$100/boe, down to an average of less than \$50/boe in 2015-2016, upending the energy landscape [4]. The price fall is considered to have come about due at least in part to increased competition from the U.S. fracking industry, which have seen a meteoric rise in the high price environment of the last decade. Increased production in other non-OPEC countries, such as Canadian oil sands and Brazilian offshore, also contributed to increasing the world's crude oil supply. With demand growth lagging after the financial crisis and a slowdown in Chinese growth, this surplus oil put pressure on OPEC and Saudi Arabia, which normally act as a market regulator for the world oil market. Fearing a loss of market share, Saudi Arabia decided to increase its production, thereby suspending the OPEC quota system, leading to further oversupply and significantly reduced oil prices. This situation has been persistent, despite Saudi Arabia and OPEC signaling a return of quotas and price cooperation [1].

The low price environment for oil is expected to continue in a short term market outlook

Baseline prediction of the short term outlook shows continuing low prices in the nearest term. However, both the IEA and Oxford Energy have argued that markets might see a correction, with higher prices as current oil surplus storages are depleted and new production diminishes due to low overall investments [1,5].

However, many uncertainties exist: the ability of OPEC to enforce supply cuts, shifts in demand for oil, unanticipated disruptions caused by geopolitical events (the most recent being the blockade against Qatar, which has resulted in lower oil prices due to fears over stability) and lastly the response of unconventional oil producers [5].

Tight oil has shown resilience in a low price environment with reduced break even prices

Due to the high marginal prices of oil sands and tight oil, much concern has been voiced over their ability to cut costs and persist in a low price environment. Initially, there was observed a dampening of activity and some well-closures. However, the tight oil producers adapt quickly, reducing well-head break even prices from \$80/b in 2013 to \$35/b in 2017, see figure 4.2 [6]. While these prices still do not reflect initial investment and facility costs, they

nonetheless show the ability of shale to continue production.

As cost-cutting steps come into effect more drilling rigs have resumed operations, with the number of total active rigs increasing by 100% from 2016 to 2017 [6]. Still there are risks that rising break even prices might emerge due to cyclical and structural drivers. Tight operators have focused on balancing cash flows, foregoing investment. To recover there needs to be a correction in the market and a rise in prices, that would allow operators to improve cash flows.

The future of tight oil is dependent on the development of oil prices in a short term view

Oxford Energy proposes that if markets correct, U.S. tight oil producers might still be able to continue growing if producers are able to respond quickly and ramp up production [5]. There are many smaller players in tight oil who make lower initial investments that take shorter time to achieve first oil than conventional larger scale producers. The short term outlook for tight oil can therefore be said to look better than many expected, however, if the market correction does not occur, it will be harder for operators to maintain investment and production levels.

Production capacity is expected to increase for oil sands and extra heavy oil

Open mining and in situ of oil sands and extra heavy oil are larger projects and have higher initial investment costs and longer completion time than hydraulic fracturing. Many large projects are coming online over 2016/2017 with a production increase from around 2.1 million boe/d in 2015 to 2.8 million boe/d by 2020, despite high break even prices [7]. New operations and more use of in situ may also contribute to lower the marginal cost levels in the short term.

Rapid expansion of oil sands and extra heavy oil is expected to halt with lower investments due to market conditions and bottle necks

Despite some cost improvements oil sands growth is likely to slump in the short term. New investments have already fallen from US\$17bn in 2015 to US\$11,3bn in 2016, and is set to remain low [7]. Uncertainties are also linked to the lack of pipeline infrastructure, which creates oversupply in bottlenecks and lower realized prices for operators. In the event of a market correction there is also the risk that a positive tight oil response might prevent a significant price increase in the short term.

4.3 Short term gas market outlook

Unconventional gas production continue to cut costs and obtains slight growth despite sluggish gas demand

The gas market is regional and defined by local demand and available infrastructure

Unlike the oil market, the gas market is less global. Whilst oil can largely be exported freely to any market and traded in the global market, gas is not as easily transported and is often linked to regional supply and demand. Global gas prices are therefore less susceptible to geopolitical events and competition compared to oil, and more defined by domestic consumption. However, the gas market is becoming more globalized, through increased export capabilities based on Liquefied Natural Gas (LNG) technology, which involves condensing gas into a more compact transportable liquid [1].

In recent years the growth in global gas demand has been halted due to both availability and competing technologies

The IEA recorded a slump in global gas demand in 2014, which returned to growth in 2015, albeit well under historic averages [8]. Drivers include the decline in energy intensity of the world economy, and reduced demand growth for all fossil fuels, including gas. The energy transformation in China, the world's biggest importer of energy, is especially significant for the general outlook [8].

European markets have long been grappling with a rapidly diminishing EU gas production, prompting more reliance on exports from Norway, North Africa, Russia and Qatar causing concerns over security of supply. Many looked to the U.S. as a supplier of LNG, investing in new LNG regasification terminals and gas

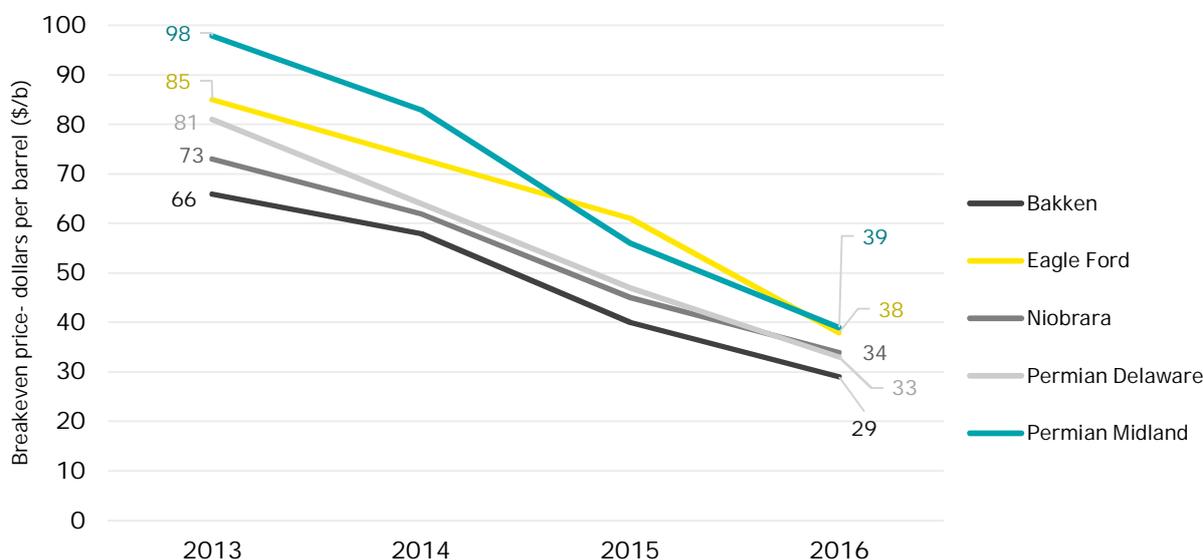
power plants. Though LNG is a relatively expensive technology, the EU has a strategic desire to reduce its reliance on Russia for natural gas.

In the EU total gas consumption is expected to be flat or fall, due to current and potential policies and gas being priced out of the market by renewable energy or coal. Despite this, imports may still increase due to falling domestic production. This situation looks to continue into the short and medium term, with uncertain market conditions for new gas developments and U.S. LNG [5,9].

The fracking industry has shown great resilience with reduced prices, and are expected to experience production increase

The U.S. gas market faces diminishing domestic demand growth, with the IEA forecasting that domestic U.S. gas consumption might slump due to competition from renewable energy in the power sector, which will limit growth in gas-fired electricity generation. Accordingly, production levels will remain relatively flat throughout 2017 [1]. Still, they point out that maintaining current gas production levels is a remarkable feat, given overall lower prices for gas. The agility and resilience of U.S. fracking industry has allowed for significant cost reductions in gas production as shown in figure 4.2 from Rystad Energy. The IEA therefore forecasts an increase in overall production by more than 100 bcm for 2021, to the point where U.S. gas production will account for one-third of global incremental production.

Figure 4.2: Development of wellhead breakeven prices for key shale plays



Source: Adapted from Rystad Energy [6]

4.4 Long term scenarios for unconventional oil

IEA's New Policies Scenario, which predicts moderate climate action, does not expect oil demand to peak before 2040, with a continuously increasing oil price establishing a growing market for unconventional oil

A geographical change in global oil demand

The IEA New Policies Scenario predicts a geographical change in global oil demand, where India will have the largest growth while China will overtake the U.S. as the single largest oil consuming country in the early 2030s [1].

Oil demand is not expected to peak before 2040, with limited effects from the Paris Agreement

The scenario models that the Paris Agreement will not lead to a peak in oil demand before 2040, due to difficulty finding alternatives to oil in road transport, aviation and petrochemicals. As seen in figure 4.3, the expected oil demand in 2040 is expected to be 103mb/d with an oil price of approximately \$120/b [1]. However, there are large uncertainties connected to this development, see chapter 5 for further details.

Canada's oil sands and global tight oil are expected to be the main sources of unconventional oil in the future

Unconventional oil production as a whole is expected to increase by 6,9 mb/d by 2040 (see table 4.1). Canada's oil sands and global tight oil production are expected to constitute the majority of

unconventional oil production in 2040. Of the remaining unconventional oil production extra heavy oil from Venezuela is the largest source [1].

Tight oil's recent rapid expansion is expected to halt, and production may lag behind a potential rise in oil price

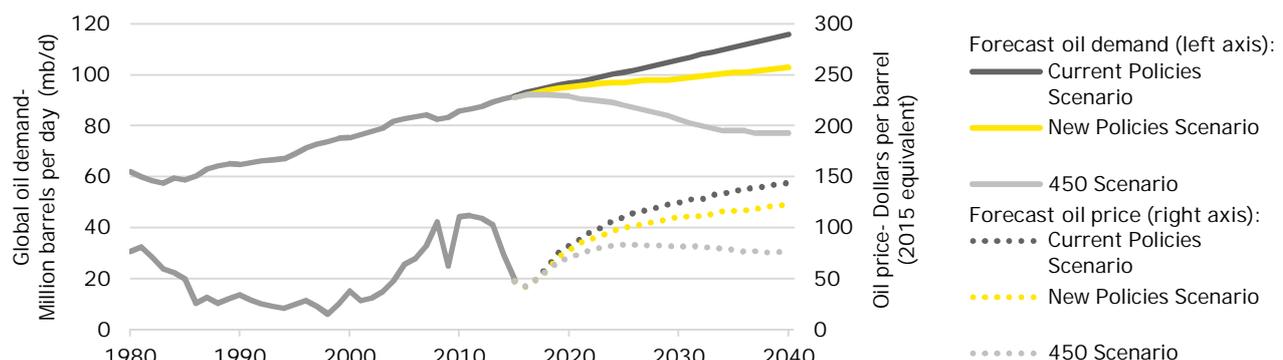
Tight oil is a good example of the uncertainty in long term scenarios. Its development from 0,5mb/d in 2010 to 4,3mb/d in 2015 reversed the 40-year decline in US oil production, and contributed to the global price fall in 2014 [1].

Tight oil production has been resilient despite the drop in oil prices. This can be attributed to many factors such as reliance on existing infrastructure. However this strategy could also contribute to slow production increases in case of a rise in oil prices.

CTL and GTL are expected to play a marginal role and cover only niche markets

CTL and GTL are only expected to increase to a marginal level, although the overall annual growth rate is substantial. CTL and GTL are therefore expected only to cover niche markets in the future [1].

Figure 4.3: Global oil demand and price historically and potential development by IEA scenario



Source: Adapted from IEA World Energy Outlook 2016 [1]

Table 4.1: Oil production from major unconventional oil sources in New Policies Scenario (mb/d)

	2000	2014	2020	2025	2030	2035	2040	2014-2040 Change (%)
Total Unconventional Oil	1,3	8,5	10,5	12,1	13,4	14,8	15,3	6,9
Tight oil	-	4,6	5,7	6,7	7,2	7,5	6,8	2,1
Canada oil sands	0,6	2,4	3,1	3,2	3,3	3,5	3,8	1,4
Venezuela heavy oil	0,2	0,4	0,7	0,9	1,2	1,5	2	1,6
Coal-to-liquids	0,1	0,1	0,1	0,2	0,4	0,6	0,7	0,6
Gas-to-liquids	0,0	0,2	0,2	0,3	0,4	0,6	0,8	0,6

Source: Adapted from IEA World Energy Outlook 2016 [1]

4.5 Long term scenarios for unconventional gas

Unconventional gas is expected to be mainly produced in the U.S. until 2020. After that, other countries such as Argentina may emerge as significant shale gas producers

Gas is expected to be the fastest growing fossil fuel, fueled by a growing energy demand

According to the IEA World Energy Outlook 2016, global natural gas demand is expected to grow by nearly half by 2040 under their New Policies Scenario (see figure 4.4). During the last 25 years the annual growth in global demand for gas has been 2,3%, and is expected to be reduced to 1,5% during the next period. However, gas is expected to be the fastest growing fossil fuel and increase its share of global primary energy demand from 21% today to 24% in 2040. The power sector is expected to account for 34% of the growth in the global gas use, with gas expected to compete with coal, especially in import-dependent markets such as Asia [1].

Unconventional gas production is expected to increase, with a high annual growth rate

As can be seen in table 4.2 the annual growth rate of unconventional gas production in the New Policy Scenario is expected to be 3,5%, compared to the global growth rate of 1,5%, meaning that unconventional gas is leading the development [1].

The U.S. is expected to have both the largest demand and production of gas

The U.S. is expected to continue to have the

largest gas demand in 2040. However, developing countries are expected to lead the growth in global gas demand (see figure 4.5).

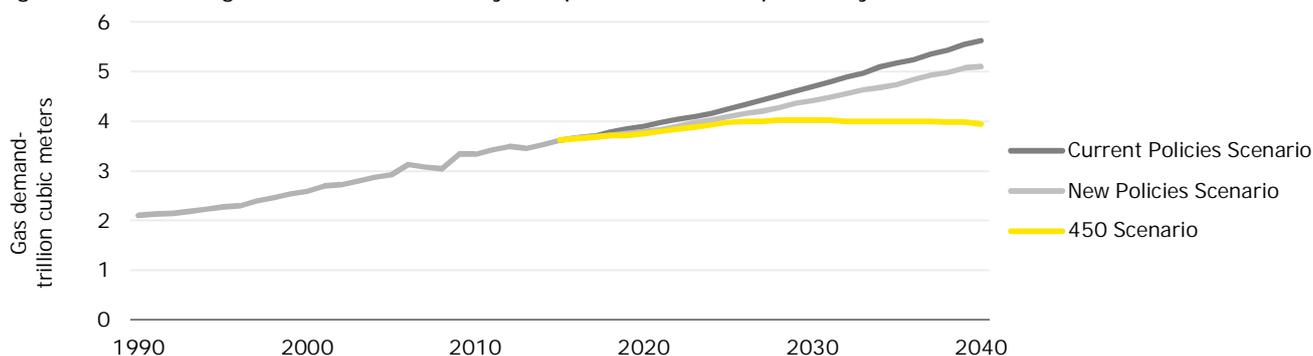
The U.S., with a large production of unconventional gas, and Australia are expected to contribute to two-thirds of the gas production growth until 2020. However, after 2020 a broad range of producers contribute, with important players including East African conventional gas producers and Argentina as a shale producer [1].

Gas is expected to develop into a globalized market through technologies such as LNG

In the IEA New Policies Scenario it is expected that LNG will capture around 70% of the additional gas trade. New pipelines will naturally be built in future decades, but it is expected that complex pipeline projects will have difficulty gathering financial and political support in a market with large adaptation to LNG [1].

Due to the expected move towards LNG, new trading hubs and a gradual removal of trade restrictions, a globalized gas market is expected to emerge. There is however expected to be an LNG overcapacity until the mid-2020s, which would require new investments in gas supply projects to avoid price volatility [1].

Figure 4.4: Global gas demand historically and potential development by IEA scenario



Source: Adapted from IEA World Energy Outlook 2016

Table 4.2: Unconventional natural gas production by region in the New Policies Scenario (bcm)

								2014-2040	
	2000	2014	2020	2025	2030	2035	2040	Change	Annual Change
OECD	195	643	845	956	1041	1127	1193	550	2,40%
Non-OECD	12	58	111	184	293	403	511	453	8,70%
World	207	701	956	1140	1334	1530	1704	1003	3,50%

Source: Adapted from IEA World Energy Outlook 2016 [1]

4.5 Long term scenarios for unconventional gas

High uncertainty is connected to long-term scenarios, especially for unconventional oil and gas as these are still emerging energy sources with demand increases heavily dependent on developing countries

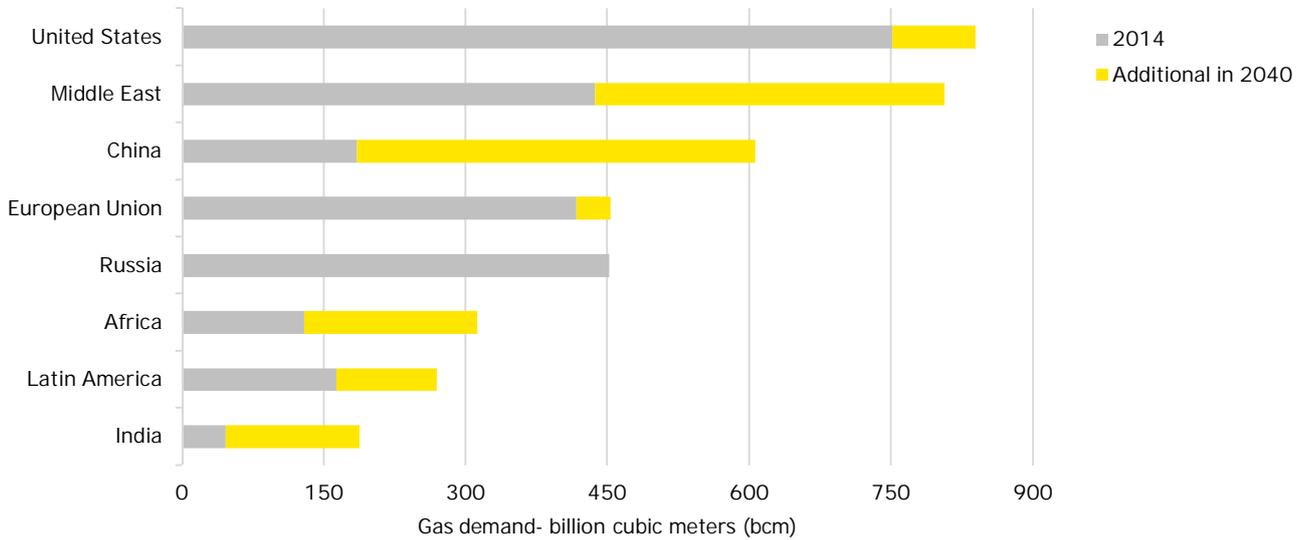
Long-term scenarios have high uncertainty, with large price elasticity

Establishing an expected long-term price scenario for gas is difficult as there are many variables in both demand and production. It is however possible to look at potential production levels based upon different prices. In figure 4.6, adapted from the IEA, US shale gas production is shown as a function of potential future prices. The figure shows that

price elasticity is high for low prices, but lower for higher prices.

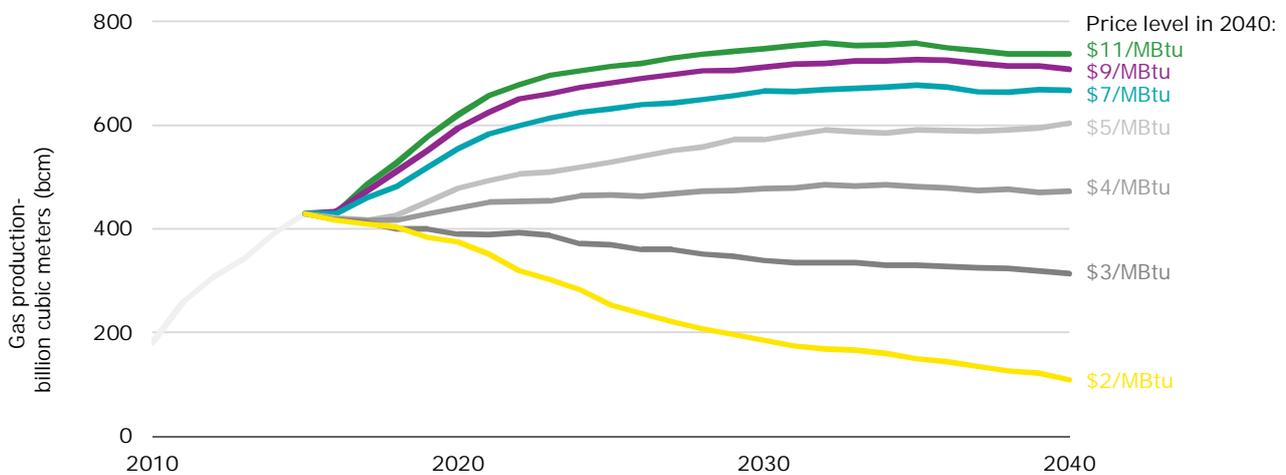
This demonstrates the difficulty in assessing long term energy scenarios. This is especially true for unconventional gas, which is an emerging energy source with several unknown variables. Although the IEA is a credible source, caution should be used when basing decisions on these scenarios due to the large innate uncertainties.

Figure 4.5: Gas demand by selected regions in the New Policies Scenario



Source: Adapted from IEA World Energy Outlook 2016 [1]

Figure 4.6: US shale gas production as a function of price



Source: Adapted from IEA World Energy Outlook 2016 [1]



5 Carbon constraints

The International Panel on Climate Change (IPCC) presented in its latest assessment report (AR5) a variety of climate scenarios based on modelling of how much the world could warm in the coming years [1]. These scenarios estimate the temperature increase that is likely to occur over the course of the 21st century dependent on how GHG are released into the atmosphere. Based on the IPCC's climate scenarios and related recommendations an international consensus has been established amongst nations to aim for a no more than 2°C temperature increase over pre-industrial levels. This commitment is reflected in the 2015 UN Paris climate agreement, which is legally binding for all signatories, and aims to avoid the most damaging effects of climate change [2].

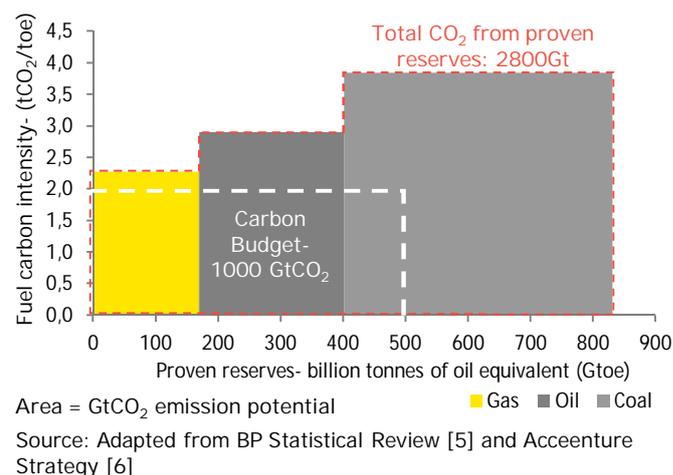
The global 'carbon budget', i.e. the amount of greenhouse gases that can be emitted while staying below 2°C warming, can be estimated based on climate modelling. The IPCC in the AR5 synthesis report estimate a remaining carbon budget of 1000 GtCO₂ as of 2011 if we are to have a 66% chance of staying under 2°C warming [3]. Based on emissions of roughly 40GtCO₂ per year over the last 5 years, this budget as of 2017 is less than 800GtCO₂, with just 20 years left of GHG emissions at current levels before the 2°C limit is exceeded.

Based on current trends, the world is on track to significantly exceed its carbon budget, and therefore widespread cuts and mitigation of carbon emissions are needed. This has led to the notion of 'unburnable carbon', with The Carbon Tracker Initiative estimating that at least 2/3 of proven fossil fuel reserves globally as of 2013 will need to remain unburned to stay within the 2°C target [4] (see figure 5.1 that shows the carbon budget calculated in 2011 compared to estimates of total proven fossil fuel reserves). Furthermore, oil companies have started to recognize the issue, such as BP who have shown similar estimates of unburnable carbon [5].

While the budget itself is known, there is less certainty as to how cuts will be managed and how this will impact the fossil fuel industry. As global climate efforts are gaining pace, there has been increasing debate about what is termed as a 'carbon bubble', where it is argued that fossil fuel companies are currently overvalued because they do not appropriately internalize the constraints set by the world's carbon budget. Proponents of this theory argue that fossil fuel investments and resources would see their value decrease substantially with the risk of becoming 'stranded assets' in the event that the world were to stay within the carbon budget [4]. There is however uncertainty as to whether the carbon bubble is already accounted for in the valuation of assets, and to what degree fossil fuel assets would in fact become stranded, with much depending on future policy and development.

While the previous chapter focused on market developments without climate constraints, this chapter will instead focus on scenarios that assume a 2°C budget constraint. This explores several different possible pathways for a low-carbon transition and how this could impact unconventional oil and gas.

Figure 5.1- Fossil fuel proven reserves versus carbon intensity



5.1 Carbon constraints - key findings

Under a 2°C carbon constraint, the majority of the world's fossil fuels would need to remain unburned

In a 2°C scenario the IEA predict a dramatic decline in fossil fuel demand

This will result in an 18% reduction in oil production and 38% for coal. However, global gas demand will grow by 16%. Unconventional gas therefore sees a 2.2% growth even in a 2°C scenario. Unconventional oil will have a tougher outlook, but can still achieve 0.8% growth until 2040 as conventional production diminishes [7].

Oil sands are not a viable option if carbon emissions and marginal prices are optimally allocated within the 2°C budget

In an unburnable carbon scenario 88% of the world's coal reserves, 52% of gas reserves and 33% of oil reserves, need to remain unburned by 2050. Tight oil would see a small growth opportunity, but half of current reserves would be left stranded.

Unconventional gas in the U.S. would see the least reserves stranded, but a "fracking revolution" would be unviable on a global scale under a 2°C budget.

Several key factors would lead to falling demand for fossil fuels and unconventional oil and gas

Increased renewable energy production, higher uptake of electric vehicles or shifting more of the burden of climate emission cuts from developing to developed countries, could see the market shares for unconventional oil and gas fall.

In a 2°C scenario, private fossil fuel companies could be more exposed than national companies, and see more reserves and capex spending become stranded assets

For private oil companies up to 68% of reserves could become stranded assets, and up to 59% of currently planned CAPEX spending could be lost. Oil sands would be harder hit due to high initial investments, while fracking projects are less exposed due to shorter investment cycles [16].



5.2 IEA 450 Scenario

The IEA 450 Scenario predicts a gradual decline in overall fossil fuel demand with some potential risk of stranded assets and lost investment. However, this is dependent on an optimistic forecast for carbon capture and storage (CCS) technology

Energy transition leads to an overall drop in primary energy demand

The 450 Scenario is the main decarbonization scenario of the IEA. It differs greatly from the other two main scenarios, the Current Policies Scenario and New Policies Scenarios, which take their starting point in current market and policies and expected policies to see how the energy market will develop. In contrast, the 450 Scenario starts at the other end, with the base assumption that the energy market needs to change and end up at a specific level of emissions in order to limit global temperature rise to below 2°C. The IEA scenario is expected to have a 50% chance of meeting the 2°C target, relying heavily on increased growth in renewables such as solar and wind, and the implementation of carbon pricing in the world's major economies. The scenario is also very optimistic regarding carbon capture and storage (CCS), assuming that this technology will be installed on 70% of coal-fired power plants and 20% of gas power plants by 2040, compared to less than 1% of plants today. The IEA estimates only 17% of world energy production will be renewable by 2040, and many groups have found that the IEA have continually underestimated renewable growth. These and other key uncertainties connected to the 450 Scenario will be discussed further in the next subchapter.

Declining oil demand gives a tough outlook for unconventional oil, though it could expand slightly

At the most general level, the 450 Scenario predicts

a decrease in total primary energy demand from fossil fuels by 2040 (see figure 5.2), nearly 5000 Mtoe less than in their Current Policies Scenario.

This fall in demand will cause oil production to decline by 1% per year on average over the period. The crude oil price is predicted to peak around 2020, and decrease slightly to \$73,4/b in 2040, a little under half of the price expected in the Current Policies Scenario. The majority of oil production over the period will come from existing fields, tapped by infrastructure already in place. As this production declines, new fields will nonetheless be brought online with a total of 390bb additional production needed, 190bb less than in the New Policies Scenario.

Production of unconventional oil is expected to double in the Current Policies Scenario, rising from an 8% to 16% share of global oil supply, and 15% in the New Policies Scenario. In the 450 scenario however, the lower overall oil consumption reduces depletion of developed conventional reserves, leaving less market share for new unconventional development at 13%. Still, unconventional oil production will grow with an estimated annual rate of 0,8% in the period, though this is 2,7% less than in the Current Policies Scenario.

In summary, the long term outlook for oil looks less promising than for the other IEA scenarios, with overall decline in production. Nonetheless, as conventional reserves dwindle, there will still be opportunities for unconventional production to capture market share.

Figure 5.2: Global primary energy demand and CO₂ emissions in the IEA's 3 main scenarios

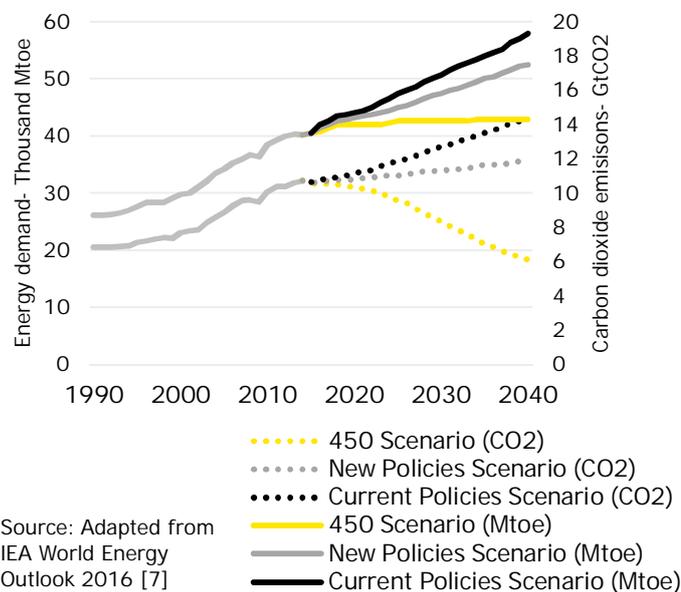
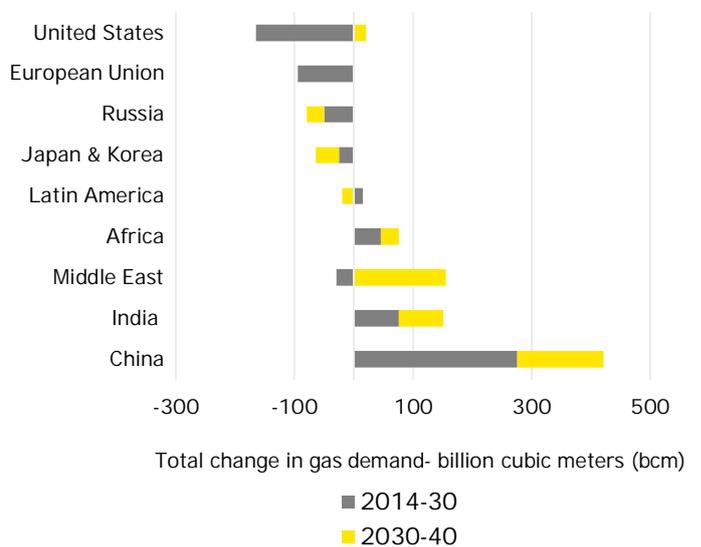


Figure 5.3: Change in gas demand in selected regions in the 450 Scenario



5.2 IEA 450 Scenario

According to the IEA, gas demand will increase slightly in the event of a low-carbon transition, while decline in oil demand leads to risks of stranded assets and foregone revenue for oil companies

Unconventional gas sees slim growth opportunities under carbon-constraining policies

Natural gas is expected to perform better despite an overall decrease in global energy demand. The demand for natural gas will remain more stable due to its lower carbon intensity, and increased use in power generation, where closed-cycle gas turbines with fast ramping speeds are more compatible with a large scale build-out of renewable energy. The IEA underlines that while natural gas is less carbon intensive than coal, it should not be misunderstood to be a “clean fuel” compatible with long term sustainable growth.

For unconventional gas the total share is expected to grow significantly, from 20% today up to 33 % in 2040 in the Current Policies Scenario (see figure 5.4). In the 450 Scenario the growth of natural gas is only expected to be slightly less – with the share of unconventional gas at 31% of total global supply. The majority of gas demand is predicted to come from China, India, and the Middle East, while for instance U.S. natural gas demand is expected to drop after 2030 (see figure 5.3). The potential of U.S. unconventional gas resources will therefore be

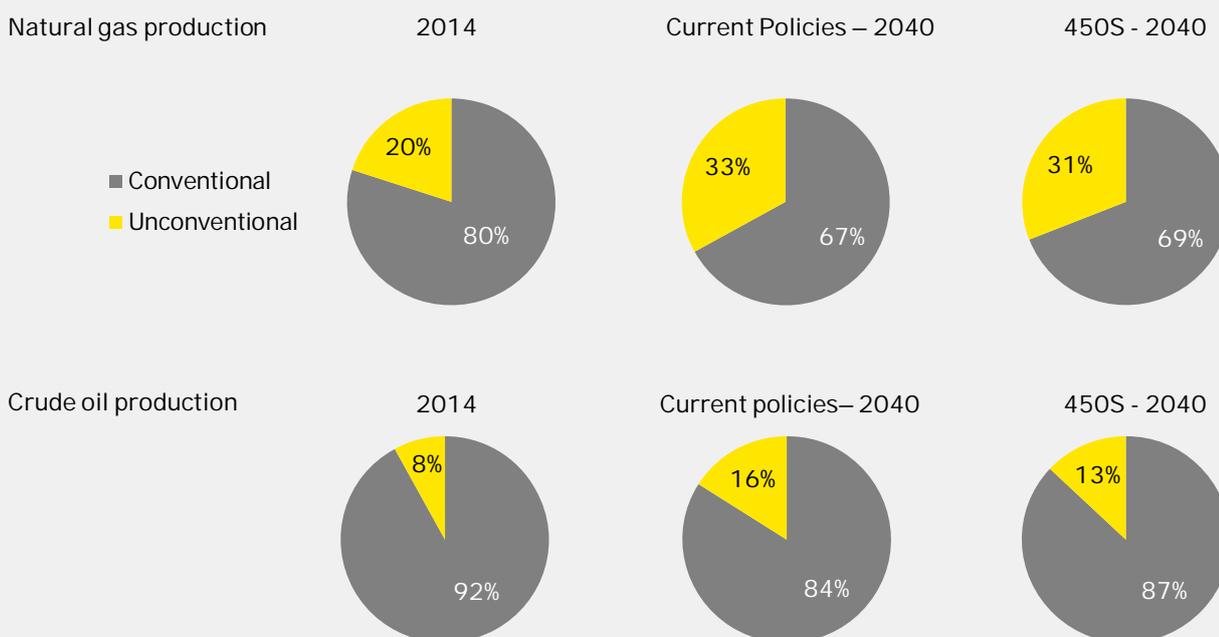
dependent on the degree to which they manage to develop sufficient LNG export capacities to remain competitive in the export market, and the willingness of developing economies to purchase U.S. gas.

The natural gas outlook is more promising. Despite low overall growth, unconvensionals can be expected to outperform conventional gas production as conventional fields run out, with an estimated annual growth of 2,2% (1,7% less than in current policies), resulting in 1/3 of the global market share.

Stranded assets in the 450 Scenario

On the question of whether this will lead to stranded assets, the IEA is less certain. While it is clear that more fossil fuels will need to stay in the ground, the risk for companies is not given, with much depending on how policies and cuts will be implemented, and how companies subsequently respond. In the event of a gradual winding down of production, the IEA argues that companies would not risk stranded assets. However, in the event of a more disorderly transition, companies could be expected to strand around 30bb of reserves as well as US\$380b of physical investments.

Figure 5.4: percentage of global oil and gas production from conventional and unconventional sources in 2014 and 2040 in the Current Policies and 450 Scenarios (450S)



Source: Adapted from IEA World Energy Outlook 2016 [7]

5.3 Key uncertainties

Rapid growth in renewables and slow adoption of carbon capture and storage could lead to reduced demand for fossil fuels

The IEA 450 Scenario is a possible pathway within a 2°C carbon budget, there are however many uncertainties in scenario building. This section therefore reviews some of the key uncertainties that could change the future outlook for fossil fuels and unconventional oil and gas.

Renewable energy implementation might exceed expectations

Development pathways for renewable energy implementation have often been significantly underestimated by modelers, as actual growth has on multiple occasions outperformed growth assumptions [9]. Furthermore, 2°C scenarios see a wide variation in renewable growth assumptions. The 450 Scenario is particularly low, predicting only a 17% share of total primary energy from renewables by 2035 [5], leaving room for 48% oil and gas, with coal and CCS carrying the rest of the cuts.

Bloomberg New Energy Finance has proposed a much more optimistic growth of renewables. Predicting large cost cuts and efficiency improvement, their scenario estimates that as much as 72% of all investments in power generation before 2040 will go to renewables [10]. Much of these predictions are already underway. In the 2016 EY report “Capturing the Sun” it is shown that as much as 80% of all solar will reach grid parity within 2018, and that renewable investments have the potential to generate between 6,6% and 10,1% annual return on investment over a period of 35 years [11].

Similarly, MIT’s 2°C scenario present a 29% increase in renewables (see table 5.1), significantly higher than that of the IEA [12]. Greenpeace provide the most optimistic forecast, predicting a 38% share by 2035 [13].

What happens after 2040?

The IEA 450 Scenario stops in the year 2040, thus leaving 60 years of uncovered time until 2100 compared to most scenarios. At the cutoff, the scenario sees an 18% reduction in oil use, 38% reduction in coal, and 16% increase in gas. Compared to a trajectory compliant with the IPCC 2°C pathway, the abatement curve associated with the IEA scenario will need to be significantly steeper for the period 2040- 2100 than in the period before 2040 in order to stay within the limitations of the carbon budget by 2100. In this regard, the IEA 450 Scenario actually postpones the majority of cuts to the second period, expending more of the budget for fossil fuels in the near and medium term, an arguably risky strategy.

According to an IPCC scenario analysis published in Nature by Rogelj et al [14], half of emissions would have to be cut by the late 2030s for a 66% chance of staying within the 2 °C carbon budget. For a 50% chance of staying within the 1,5 °C budget, they would have to be halved by early 2030s. This is directly conflicting with IEA 450 Scenario estimates and prescriptions, indicating a need to cut more GHG emissions in the near term.

Table 5.1: Annual change in emissions and total primary energy consumption from 2015 to 2035 following scenarios from BP, IEA, MIT, IHS and Greenpeace and total share of energy in 2035 in these scenarios.

	BP faster transition	BP even faster transition	IEA 450	MIT 2° Base	IHS Market 'Solar Efficiency'	Greenpeace 'Revolution'
CAGR (%) * 2015-2035						
Carbon emissions	-0,7%	-2,0%	-2,0%	-2,0%	-2,8%	-3,2%
Total energy	0,9%	0,8%	0,4%	0,5%	-0,7%	-0,1%
Share of total energy, 2035						
Oil & gas	51%	48%	48%	46%	51%	39%
Renewables	16%	23%	17%	29%	19%	38%

*CAGR = Compound (mean) annual growth rate

Source: Adapted from BP Energy Outlook 2017 [5]

5.3 Key uncertainties

Sustained market shares for fossil fuels are highly dependent on CCS and negative emission technology, despite little progress in achieving widespread commercial deployment in the last decade

Uncertain future for CCS and negative emissions technology

Generous assumptions for CCS provide a big uncertainty. To date, CCS technology has not delivered on its promise. The IEA responds to this each year by delaying the onset of CCS by a certain amount of time, reducing its total share only minimally. However, given the rapid increase in performance of other low carbon technologies, the advent of CCS on a mass scale becomes more unlikely. It might therefore not only be a question of when but whether CCS will become a competitive low carbon technology for power generation. If CCS does not realize its potential, fossil fuels, both conventional and unconventional, would have to be cut to a much larger extent, as discussed in the Unburnable Carbon Scenario in the next subchapter. However, it is also possible, though increasingly unlikely, the opposite could occur with strong implementation of CCS, that results in coal, with its lower marginal cost base, keeping a higher market share than gas.

Similarly, negative emission technology is assumed by the IEA. This technology is based on burning sustainable biofuels with carbon capture and storage. This would allow for a 'permanent' sequestration of carbon that has been removed from the atmosphere by the plants whilst they grow. By including negative emissions the IEA actually overshoot on the 2°C budget. Negative emissions technology is however still unproven at scale, and provides a high uncertainty factor in the 450 Scenario. Without negative emissions, deeper and more abrupt cuts would be required compared to the more gradual abatement curve predicted by the IEA.

Low carbon transportation could further reduce fossil fuel demand

The continuation of the dominance of the internal combustion engine vehicles is one of the key factors for the future of oil demand. In the case of a rapid, large scale uptake of electric vehicles, this would significantly dent oil demand. The IEA 450 Scenario considers a global stock of electric vehicles that exceeds 710 million in 2040 displacing more than 6mb/d. However, Bloomberg New Energy Finance believe it is possible that electric vehicles may displace 2mb/d by as early as 2023 and 6mb/d by 2030 [10] which would have serious ramifications for oil demand.

Who will carry the burden?

Lastly, the scenario predicts that emission reductions will occur in developing countries. The 450 Scenario estimates that developing countries will participate significantly in providing emission cuts. However, given the reality of climate emission cuts to date this assumption can be considered uncertain, especially from a perspective of equality in burden sharing. Developing countries rely more on coal for their energy use than more developed economies. In the event that developing countries do not meet their mitigation targets, a greater burden would have to be carried by the developed world to keep emissions within the carbon budget. This would therefore imply larger cuts in existing oil and gas production than previously expected.

5.4 Unburnable Carbon Scenario

In a carbon constrained world the majority of current fossil fuel reserves must remain unburned

Prioritizing production of the least GHG intensive and lowest marginal cost hydrocarbons

In 2015, McGlade & Ekins [8] published an article in the academic journal Nature, presenting a breakdown of how much of the world's current fossil fuel reserves can be extracted and burned within the constraints of the IPCC carbon budget, and how much of the reserves should remain in the ground as so-called unburnable carbon (see figure 5.5).

Their main finding is that if we are to stay within the carbon budget, 88% of the world's coal reserves, 52% of gas reserves and 33% of oil reserves, need to be left unburned by 2050. These clear cut findings have made the article one of the most cited climate change articles of recent years, and a natural reference point for any discussion of how a 2°C future should look.

The approach differs significantly from the IEA. While the 450 Scenario makes assumptions in a wide range of areas, including policy, technology, and geopolitics to estimate future production levels, the McGlade & Ekins study is instead focused primarily on cost-efficiency and carbon intensity. Scenarios for production cost development of the various conventional and unconventional fossil fuels are inserted in a complex energy system model, with a base assumption of maximizing socio-economic benefit. The model presents a very theoretical result, showing the "perfect" allocation of the world's remaining carbon budget, which maximizes the utility from fossil fuel taking into account their carbon emissions and marginal cost.

While this is not a politically prescriptive solution like that of the IEA, it gives a much clearer depiction of the consequences of carbon constraints, as well as

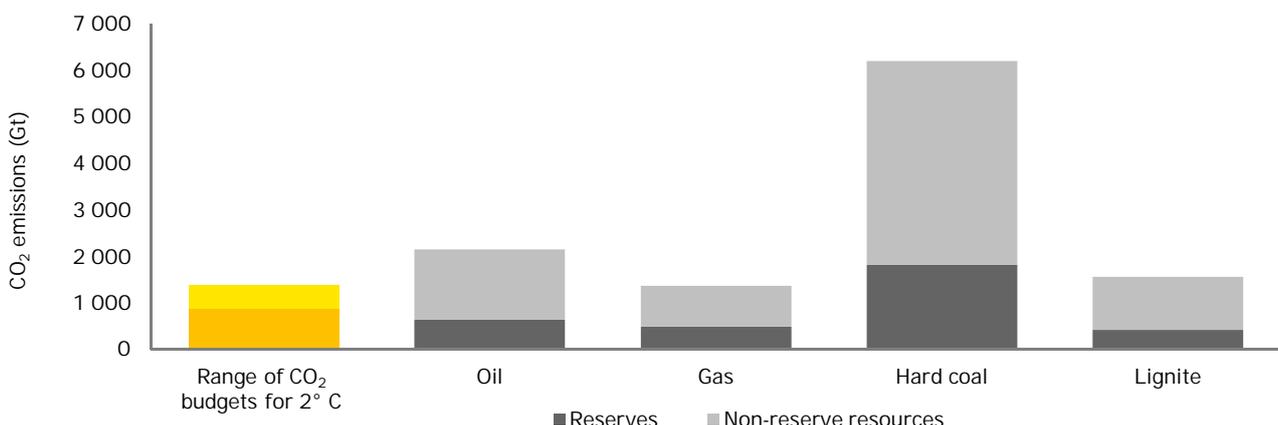
the amount of production cuts necessary to reach a 2°C target. The report is therefore useful in giving an overview of future emission cuts and mitigation strategies. However, the results say nothing of whether the outcome is probable or not.

Importantly, the study also focuses first and foremost on reserves, known and production ready resources, under the assumption that remaining ultimately recoverable resources will not be developed. The authors do however point out that oil and gas resources that are not currently considered as reserves, may turn out to be cheaper to produce than some existing reserves. New resources may also be developed to cover local or global demand. The implications however is that if there are developments of non-reserve resources in any region or resources type, a corresponding amount of existing reserves must remain in the ground to keep within the carbon budget constraints.

The largest producers shoulder most of the burden

In total, the authors find that 430bb of oil and 95 trillion cubic meters of gas currently classified as reserves should remain unburned by 2050. The majority of this burden is carried by oil producers in the Middle East, home to half of the world's unburnable resources of both oil and gas (see figure 5.6). Despite this, these countries are able to produce up to 60% of their respective oil reserves and 50% of their gas, due to low marginal prices and high degrees of development and utilization of current reservoirs. Russia and the former Soviet countries would also have to take one third of the total cuts in gas production. For coal, Russia and the U.S. would only use 10% of their respective reserves, carrying the majority of global unburnable coal, of the total of 82% that needs to remain unburned before 2050.

Figure 5.5: Reserves and non-reserves resources of fossil fuels compared to 2°C budget



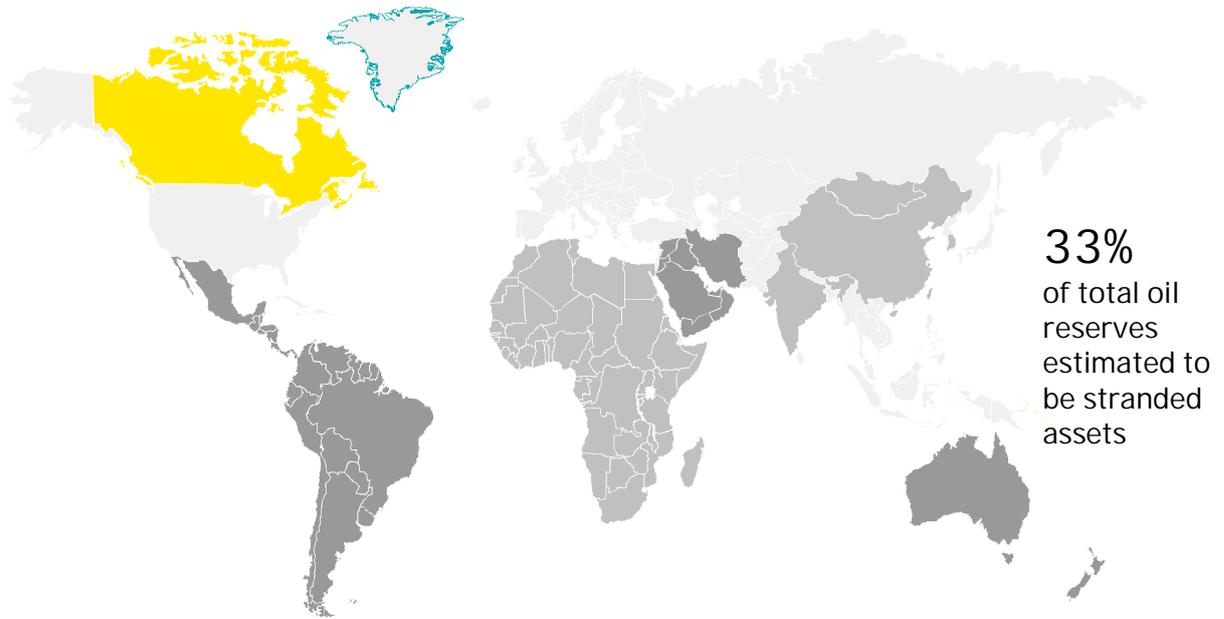
Source: Adapted from McGlade and Ekins (2015) [8]

5.4 Unburnable carbon scenario

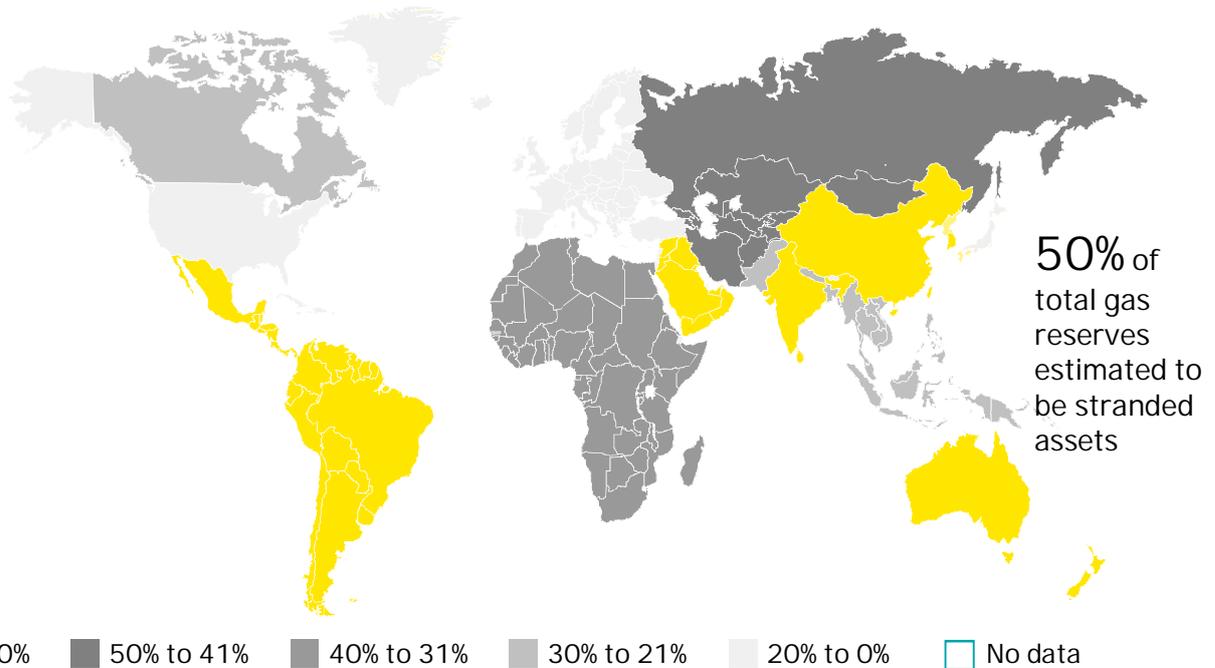
Producers with the largest reserves have most risk of stranded assets. In developing countries with low production and underutilized reserves, further development would not be possible

Figure 5.6: Breakdown of stranded oil and gas assets by region, percentage of stranded assets

Breakdown of oil stranded assets by region by % of stranded oil assets



Breakdown of gas stranded assets by region by % of stranded gas assets



■ >50%
 ■ 50% to 41%
 ■ 40% to 31%
 ■ 30% to 21%
 ■ 20% to 0%
 No data

Note: Colors represent average stranded assets per region with potential significant differences between countries within a region.

Source: Adapted from McGlade, Ekins (2015) [8]

5.4 Unburnable carbon scenario

Unconventional oil and gas production in the U.S. will be less impacted than in the rest of the world, but half of all reserves must remain unburned

Canadian oil sands must remain in the ground

The main takeaways from the McGlade & Ekins study is that given a cost and carbon efficient allocation, nearly all unconventional oil coming from oil sands would have to remain in the ground (see figure 5.7).

Due to the high emissions and marginal costs of oil sands it is harder to extract than more easily available conventional reserves. Canadian oil sands from open mining and in situ therefore drop to near zero levels after 2020, leaving as much as 99% of Canadian oil sands reserves unburned before 2050.

In situ production is continued in a separate CCS scenario, but only when accompanied by rapid and total decarbonization of all auxiliary energy inputs to the energy intensive extraction process. This process of decarbonization would prove extremely challenging with unclear cost-predictions, and would only amount to a cumulative production between 2050 to 2100 of 7.5 bb of oil, leaving 85% of all Canadian oil sands reserves unburned.

Similar results are also found for extra-heavy oil in Venezuela, where the low current development of reserves would result in over 99% of reserves left unburned. In the CCS scenario this would improve slightly to 95% of reserves.

Cautious expansion for U.S. tight oil

For the U.S., it is estimated that 52% of oil reserves would become unburnable, amounting to only 6% of the world's total unburnable oil. The study defines

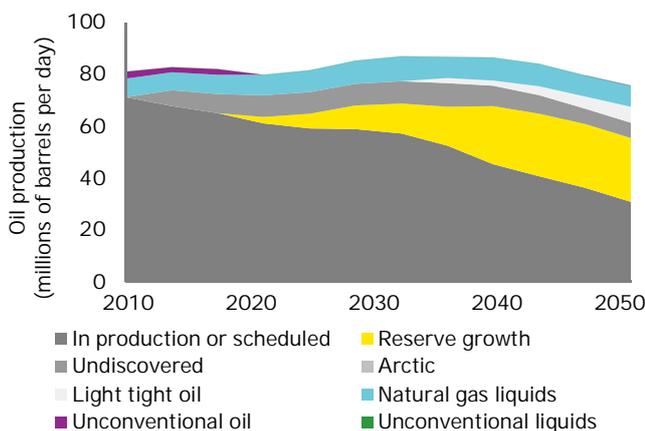
U.S. light tight oil from fracking operations as conventional oil (end product-definition). In the U.S., unconventional oil, in the form of kerogen, is estimated as 100% unburnable. As can be seen from figure 5.7, tight oil production shares will in fact increase as U.S. conventional reserves diminish, but will however become constrained along with the rest of U.S. oil production after 2050.

The majority of unconventional gas is unburnable – but less in the U.S.

Also for gas, the U.S. is better off relative to other regions, and would only need to carry roughly 4% of the world's total unburnable gas, leaving the U.S. free to use around 50% of their total unconventional reserves coming from shale, tight or CBM formations (see figure 5.8 for the global overview). A large part of the resilience for the U.S. market is based on the relative proximity between production and market. U.S. produced gas and oil would largely be supplied directly to offset future need for fuel imports as well as to offset a fall in domestic coal consumption.

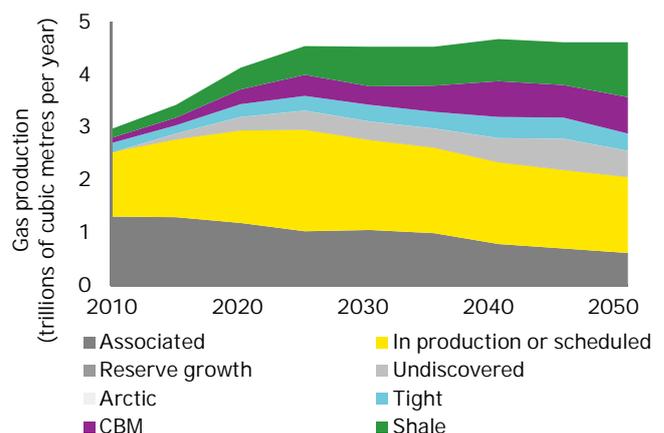
Globally however, the model estimates that around 82% of unconventional gas resources (247 tcbm) needs to remain in the ground before 2050. This means that in the event of a carbon budget, a “fracking-revolution” would not be viable in other parts of the world, particularly in China, India, Africa and the Middle East where fields are not yet developed and reserves are less utilized.

Figure 5.7 shows the yearly distribution of global oil production per category. Arctic, oil sands and heavy oil production will all but stop. Overall conventional oil is set to sink as fields diminish. Much of this will be offset by upwards adjustment of known fields, where new extraction techniques can continue production.



Source: Adapted from McGlade and Ekins (2015) [8]

Figure 5.8 shows the yearly distribution of global gas production per category. Gas production will grow as coal is phased out, with unconventional gas increasing in overall share of production. However, despite increasing shares, 82% of known unconventional gas reserves will still need to remain unburned.



5.5 Fossil fuel companies in a 2°C world

Private fossil fuel companies current capex spending and reserves are largely incompatible with a 2°C target, especially Canadian oil sands

If we are to achieve the target of limiting global warming to less than 2°C, commitment should ideally be reflected in the behavior of companies worldwide, especially those involved in extraction of fossil fuels.

As previously discussed, the IEA 450 Scenario that some assets could become stranded. The idealized Unburnable Carbon scenario goes further by suggesting the point at which assets should become stranded, or as they put it, “remain in the ground”. This risk should therefore be recognized and reported on by companies in order to give their investors and other stakeholders a clear understanding of the companies’ role in a 2°C future.

Companies need to stress test and plan for 2°C scenarios

This has recently been argued for by the Financial Stability Board’s Task Force on Climate-related Financial Disclosures (TCFD) [15]. This investor-led initiative, mandated by the G20 and Chaired by Michael R. Bloomberg, has developed a set of recommendations for how companies can effectively and consistently communicate their climate-related risks; including physical, liability and transitional risks, and do so in a way that aligns with investors’ needs and expectations. TCFD also recognizes the value of 2°C scenarios as reference points that companies can use for stress testing and financial planning.

Private fossil fuel companies can be more exposed to climate risk than national companies

The Carbon Tracker Initiative has recently published a report that seeks to link companies add current behavior against a normative baseline of IEAs 450 Scenario and 2°C carbon budget [16]. This is to shed light on the level of risks carried by companies with regards to their current reserves and capex

spending. Findings include that if we are to stay on the trajectories proposed by the 450 Scenario, a large part of fossil fuel reserves are currently outside of the budget, as illustrated by table 5.2.

Accordingly, this will have implications for companies’ investment decisions. With the amount of reserves falling outside the budget, it is estimated that up to 33% of CAPEX in the current business-as-usual spending would not have to be spent in a 2°C scenario, see table 5.3.

Similarly, 31% of gas capex will also be redundant. In the short term this would be even higher: 60% of North American capex would be surplus according to the 2025 levels of the 450 Scenario. Furthermore, due to the type of reserves held by private oil companies, they would be more exposed than national oil companies, and would carry 68% of the redundant reserves.

Oil sands would be worst off due to large projects and high initial investments

The analysis also shows that oil sands companies in general would not perform well, reflecting the many challenges posed to the industry from GHG limits and the need for high capex investments to expand operations and construct export infrastructure.

Shale and fracking operators are however more spread along the cost curve, which does not deliver a uniform conclusion, given larger variation in companies’ performance. As described in earlier chapters, fracking operations have a shorter project cycle and lifetime. This allows for more flexibility in reducing investment and lowering production. Consequently, risk is therefore also carried in shorter periods than for oil sands which have high initial capital investments and long payback periods. Nonetheless, shorter risk periods expose fracking operations to short-term market variations.

Table 5.2: Potential oil and gas outside of CO₂ budget

	Within budget (GtCO ₂)	Potential outside budget (GtCO ₂)	Total (GtCO ₂)
Oil	188	32	220
Gas	132	29	160
Total	320	61	380

Source: Adapted from Carbon Tracker Initiative [16]

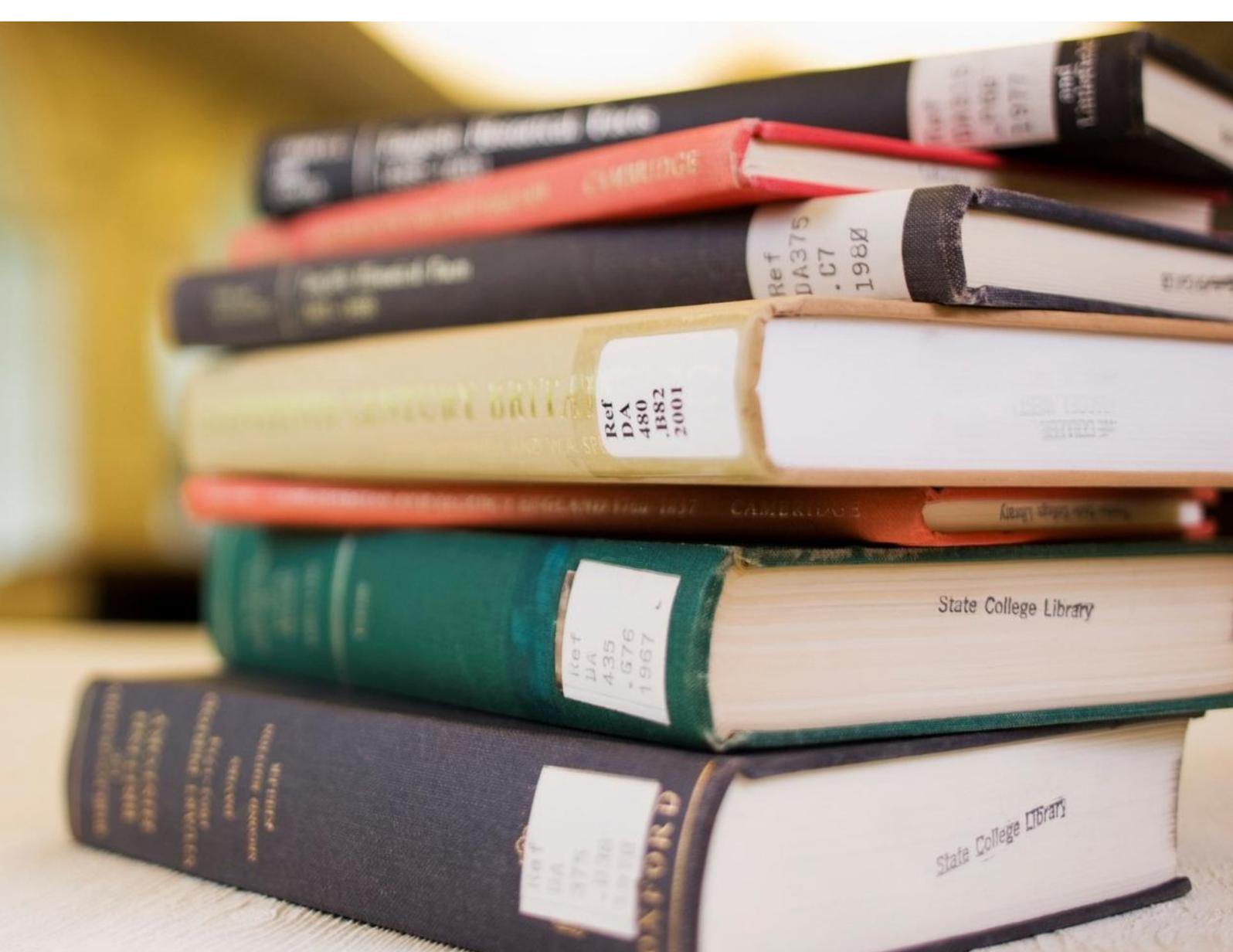
Table 5.3: Potential oil and gas outside of CO₂ budget

	2017-2035 production		2017-2035 capex	
	Needed	Not needed	Needed	Not needed
NOC+INOC % of total	54%	23%	44%	24%
Private sector % of total	43%	68%	50%	59%

NOC- National Oil Company
INOC- International National Oil Company

Source: Adapted from Carbon Tracker Initiative [16]

Appendix



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