# Charting a Path to Net Zero Emissions for Oil & Gas Production

Climate change represents a long-term threat to society and the Energy sector faces increased scrutiny for its contribution to it. Calls to divest the sector have grown but avoiding the sector does little to improve the environment. As long as the world still relies on the energy delivered by fossil fuels, investors have a responsibility to ensure that companies are producing it as efficiently, safely and environmentally friendly as possible.

Kimmeridge believes that good environmental performance is also good business. We intend to advocate for improvements in environmental performance, disclosure, verification and target setting for the Exploration and Production (E&P) sector that are measurable and impactful. As the world transitions to a low carbon future, the upstream oil and gas business must evolve and address its own environmental deficiencies. The leading E&P companies of tomorrow will adopt a business model that is aligned with the energy transition through lower reinvestment rates while charting a path towards net zero emissions in their direct operations. This is critical for attracting investors back to the sector.

For the E&P industry, a low carbon future does not mean abandoning or exiting the business. Rather it represents a world where companies operate more efficiently while measuring, reporting and minimizing their impact on the environment. Achieving this with more energy intensive forms of oil production (oil sands, steam floods, etc.) will prove difficult, which should create a platform for light, high-quality unconventional plays to distinguish themselves.

The purpose of this paper is to provide a comprehensive overview of upstream oil and gas emissions, identify the specific actions necessary for alignment with the Paris Agreement and address the role of corporate governance in effectuating change.

## Goals

Kimmeridge intends to advocate for change in the sector through its investments. We believe that companies we invest in should adopt the following five key principles:

1) **Eliminate routine flaring by 2025**
2) **Reduce US methane intensity below .2% of gas production by 2023**
3) **Reduce total upstream GHG intensity by 50% by 2030**
4) **Pursue routine monitoring and independent verification of emission levels**
5) **Align reporting with SASB standards and adopt all 11 TCFD recommended disclosures by 2022**

Importantly given our dual role as both a public equity investor and direct operator, Kimmeridge will be adopting each of these goals in our own operations.

This paper should be read in conjunction with our previous paper (Preparing the E&P Sector for the Energy Transition: A New Business Model) that outlines our recommendations for reforming the E&P business model. We maintain that for E&P companies to become investable again they must address their operating model, their environmental performance and their executive compensation/governance. Frequently these are related. Lowering reinvestment rates and focusing on profitability would, in many cases, eliminate wasteful growth and flaring. Incentivizing management to do this will require rethinking pay structures and peer groups so the industry is compared to a broader Industrial peer group with true pay for performance. With management and boards compensated to maintain the status quo, few will embrace the necessary changes without investor pressure. This only underscores the need for engagement over divestment.

## Oil & Gas Emissions

Before discussing what should be reduced it is important to understand what is measured and what is important. Generally, greenhouse gas emissions (GHG) are broken into three groups[1]:

- **Scope 1: Direct GHG emissions**: Covers all direct GHG emissions by a company. It includes fuel combustion, company vehicles and fugitive emissions.
- **Scope 2: Indirect emissions from purchased electricity.** Covers indirect GHG emissions from consumption of purchased electricity, heat or steam.
- **Scope 3: Other indirect GHG emissions**. Covers other indirect emissions, such as the extraction and production of purchased materials and fuels, transport-related activities in vehicles not owned or controlled by the reporting entity, electricity-related activities not covered in Scope 2, outsourced activities, waste disposal, etc. *Scope 3 emissions (also known as value chain emissions) often represent the largest source of greenhouse gas emissions and in some cases can account for up to 90% of the total carbon impact.*

The two most prominent greenhouse gases are carbon dioxide ($CO_2$) and methane ($CH_4$) while nitrous oxide and chlorofluorocarbons are less relevant for oil and gas. According to the EPA, the way in which these gases differ from each other are their ability to absorb energy (radiative efficiency) and how long they stay in the atmosphere (lifetime). The Global Warming Potential (GWP) measure is utilized to allow comparisons of the global warming impacts of the different gases. It is effectively a way to measure how much energy the emissions of one ton of a gas will absorb over time, relative to the emissions of one ton of carbon dioxide ($CO_2$). The larger the GWP, the more that a given gas warms the Earth compared to $CO_2$. The time period usually used for GWPs is 100 years. GWPs provide a common unit of measurement, which allows analysts to add up emissions estimates of different gases and allows policymakers to compare emissions reduction opportunities.

- Carbon Dioxide, by definition, has a GWP of 1 regardless of the time period used, because it is the gas being used as the reference. $CO_2$ remains in the climate system for a very long time: $CO_2$ emissions cause increases in atmospheric concentrations of $CO_2$ that will last thousands of years.
- Methane is estimated to have a GWP of 28–36 over 100 years. $CH_4$ emitted today lasts about a decade on average, which is much less time than $CO_2$. But $CH_4$ also absorbs much more energy than $CO_2$. The net effect of the shorter lifetime and higher energy absorption is reflected in the GWP.
- Nitrous Oxide ($N_2O$) has a GWP 265–298 times that of $CO_2$ for a 100-year timescale. $N_2O$ emitted today remains in the atmosphere for more than 100 years, on average.

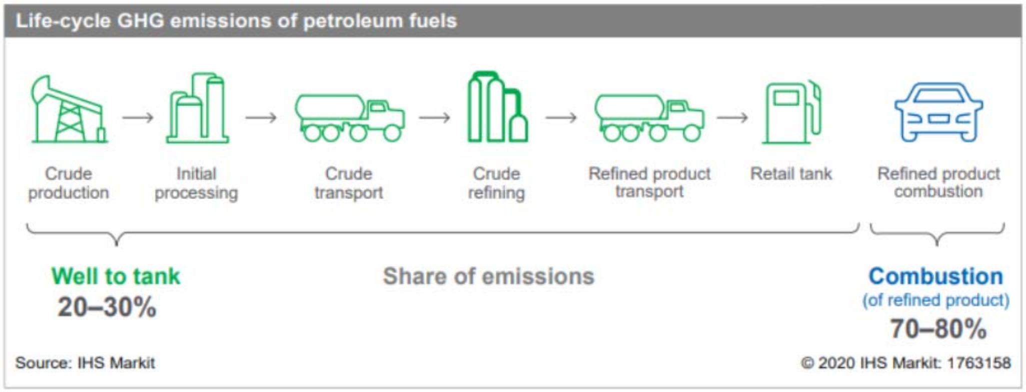
[1] https://ghgprotocol.org/ & https://www.carbontrust.com/

- Chlorofluorocarbons (CFCs), hydrofluorocarbons (HFCs), hydrochlorofluorocarbons (HCFCs), perfluorocarbons (PFCs), and sulfur hexafluoride ($SF_6$) are sometimes called high-GWP gases because, for a given amount of mass, they trap substantially more heat than $CO_2$. The GWPs can be in the thousands or tens of thousands.[2]

This protocol allows for emissions to be stated on a CO2 equivalent basis ($CO_2e$).

According to a McKinsey study, 42% of total global emissions ($CO_2e$) are attributable to the oil & gas industry. Of that roughly 20% is from oil & gas operations (Scope 1 & 2) and the remaining 80% is from indirect consumption of the products (Scope 3). The direct operations of the industry are responsible for 8-9% of global emissions, with over half coming from upstream oil & gas production[3].

**Figure 1: Life-Cycle of GHG Emissions**




While society increasingly wants to hold the oil & gas industry responsible for the emissions associated with the combustion of their products, this ignores the role they are playing in satisfying a market need. The world's reliance on fossil fuels is ultimately a demand problem, not a supply problem. We believe that consumers should understand where emissions are generated and hold each company accountable for their own Scope 1 emissions. When Uber has helped add over seven billion incremental miles driven across just nine cities,[4] boosting global oil demand, it makes no sense to vilify E&P companies while praising ride-sharing companies. However, if oil and gas producers, refiners and a company like Lyft (who notably has committed to offsetting all emissions[5]) take individual responsibility, then "net zero" is an obtainable goal.

This report focuses on what the US E&P industry can do to minimize their own environmental footprint and materially lower the emissions intensity of producing oil and gas. It also addresses the credibility gap associated with these actions in the absence of improved monitoring and independent verification of emission levels. It is important to understand that the emissions data companies report to the EPA is estimated based on bottom-up inventory factors (component based) rather than top-down observations (atmospheric readings). As the Environmental Defense Fund (EDF) cites in their feedback

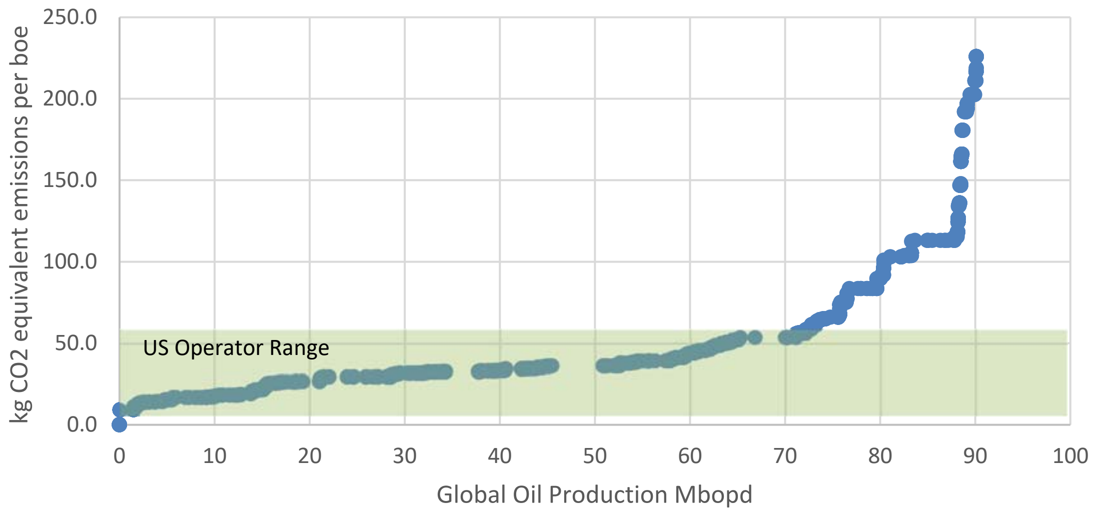
[2] https://www.epa.gov/ghgemissions/understanding-global-warming-potentials
[3] https://www.mckinsey.com/industries/oil-and-gas/our-insights/the-future-is-now-how-oil-and-gas-companies-can-decarbonize
[4] http://www.schallerconsult.com/rideservices/favfact6.htm
[5] https://www.lyft.com/blog/posts/lyft-commits-to-full-carbon-neutrality-and-100-renewable-energy

to the EPA, "while component based estimates are valuable for understanding the approximate allocation of emissions among sources, they are not suitable for estimating total emissions without the support of other empirical data, because component-level studies under-sample abnormal operating conditions which are responsible for a very substantial portion of real emissions."[6] As is the case with all aspects of public market investing, credible analysis of company performance is contingent on data integrity.

## Breaking Down US Upstream Emissions

Perhaps surprisingly, the US E&P industry is starting from an advantaged position of having a low GHG intensity barrel of oil, which the world should prioritize as the energy transition progresses. For the 33 public E&P companies Kimmeridge analyzed, which represent close to 5 million barrels a day of gross operated production, US upstream emission intensity averaged 30 $CO_2e$ per barrel.[7] The range was 8 to 66 $CO_2e$ per barrel, which falls within the top 75% of global oil production.

**Figure 2: US E&P $CO_2e$ Emissions vs. Production**

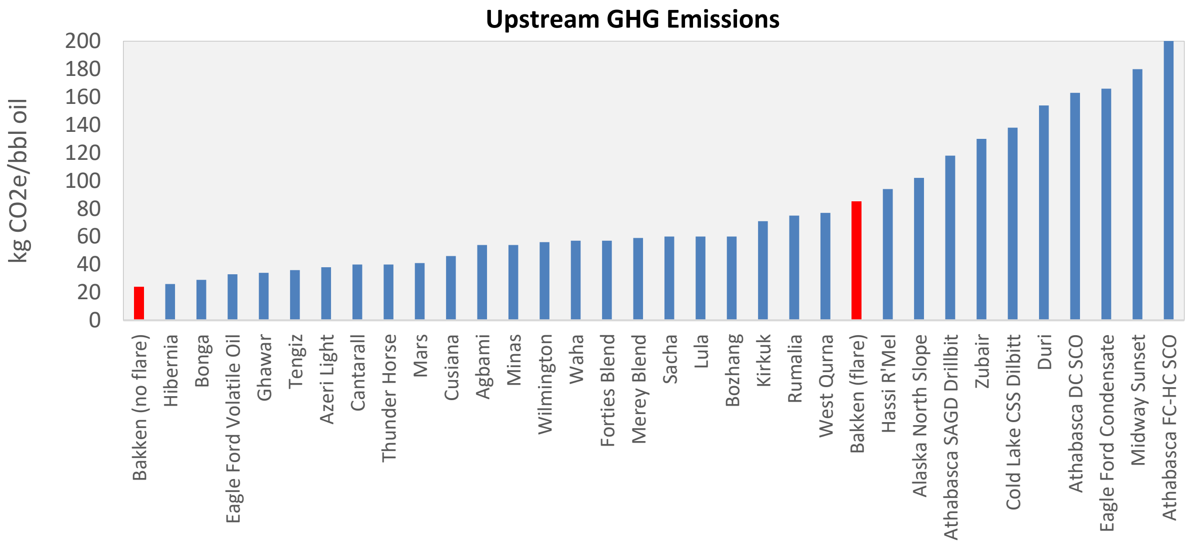



Source: IEA Methane Tracker 2020

But operators must urgently address the environmental deficiencies still inherent in the extraction process. As the chart below shows, flaring gas in a play like the Bakken can be the difference between being well below or above the average emission intensity of various global crudes. Essentially how the producer handles the product after it comes out of the reservoir can explain over 70% of Scope 1 emissions.

[6] https://www.epa.gov/sites/production/files/2018-10/documents/epa_2019_ghgi_memos_-_edf_catf_feedback.pdf
[7] https://ghgdata.epa.gov/ghgp/

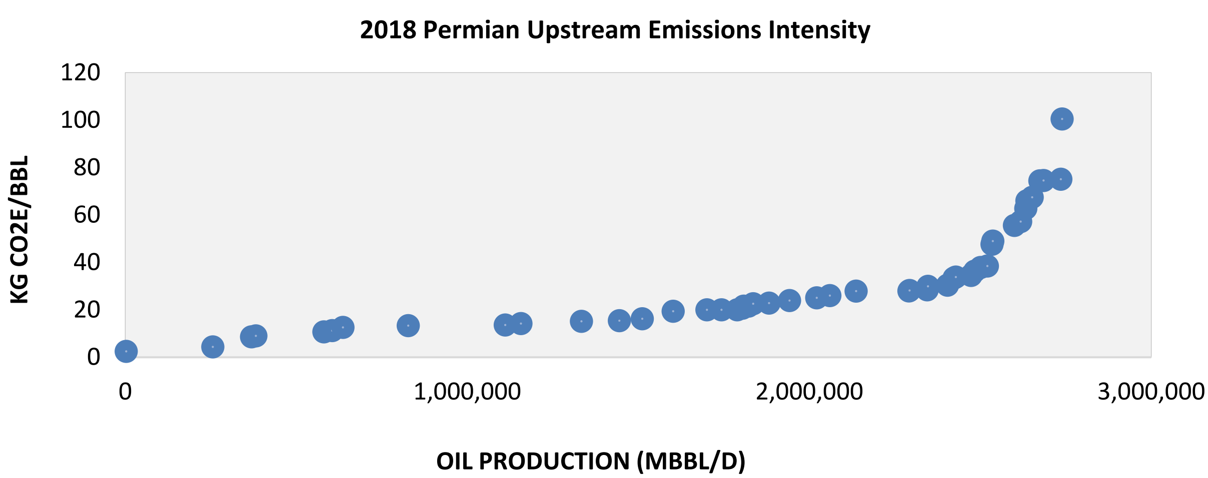
### Figure 3: Upstream GHG Emissions by Producing Area




Source: Oil-Climate Index Carnegie Endowment

This is the reason why even within a specific basin like the Permian we observe a high degree of dispersion of operator emission intensity. While 80% of the production in 2018 had a weighted average intensity of 17 kg $CO_2$e per barrel, the bottom 20% was over 56 kg $CO_2$e per barrel. In an industry that will only be perceived to be as good as its worst actors this is unacceptable, especially as these inventory-based calculations likely underestimate actual emission levels. Investors, both public and private, must do their part to hold these companies accountable for raising their environmental standards.

### Figure 4: 2018 Permian E&P $CO_2$e Emissions vs. Production

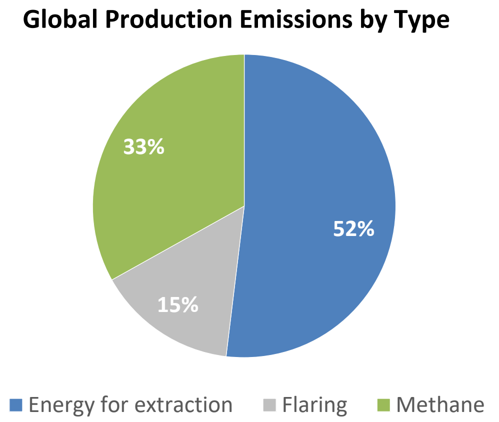



Source: EPA FLIGHT Data

**What are the drivers of upstream emissions?**

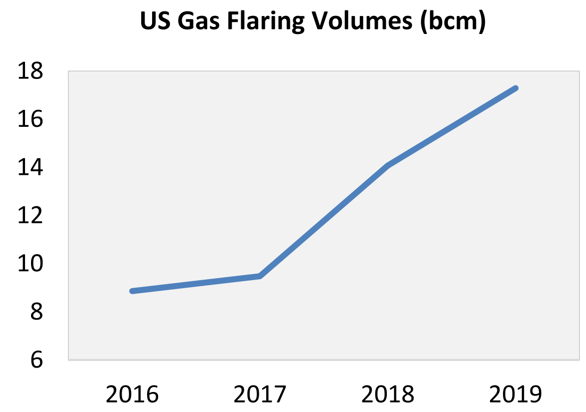
Looking at the nature of these emissions they can broadly be separated into three categories, 1) energy use for extraction, 2) methane release and 3) flaring. Of these, the easiest to reduce are flaring (which is largely voluntary and has grown over the last 5 years) and methane which can often be captured on location at minimal cost (addressed later).

### Figure 5: Upstream Emissions by Type




Source: IEA Methane Tracker 2020

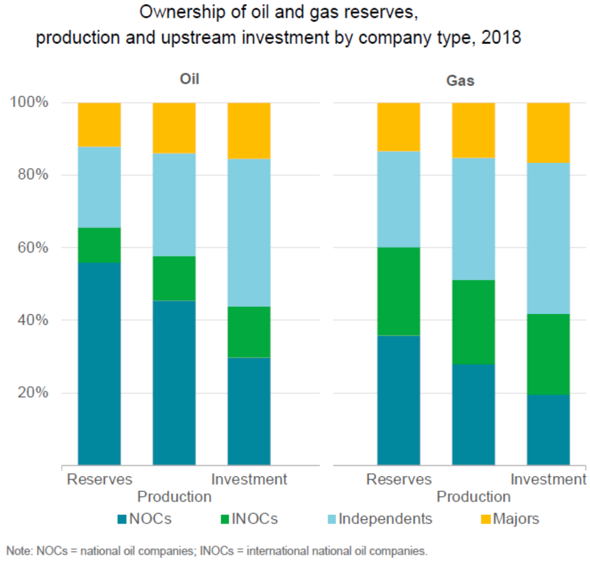
### Figure 6: US Flaring Volumes 2016-2019




Source: World Bank

While the largest integrated oil companies garner most of the public attention regarding environmental matters, the Majors only represent 10% of estimated emissions from industry operations. Notably, independent E&P companies represent a larger share of global oil & gas reserves and the most significant driver of upstream investment. Addressing the environmental performance of these companies is critical to reducing upstream emissions.

### Figure 7: Ownership of Oil/Gas Reserves, Production, and Investment (2018)

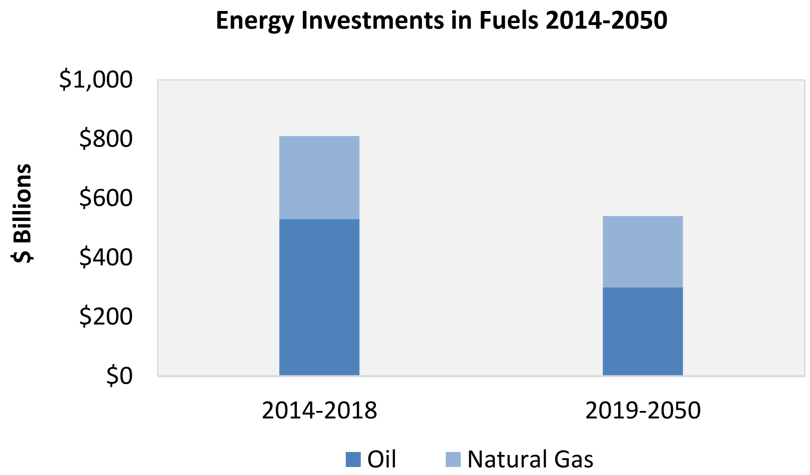



Source: IEA

## Aligning Upstream Emissions with the Paris Agreement

In their annual World Energy Outlook, the IEA outlines a Sustainable Development Scenario (SDS) that is intended to be consistent with the Paris Agreement in holding the rise in global temperatures well below 2°C and pursuing efforts to limit to 1.5°C. Under this scenario, global emissions ($CO_2e$) fall from 33 Gt in 2018 to less than 10 Gt by 2050 and approach net zero emissions by 2070. The most significant long-term implication for the upstream sector is the implied 37% reduction in required annual oil and gas investment levels relative to the 2014-2018 average:

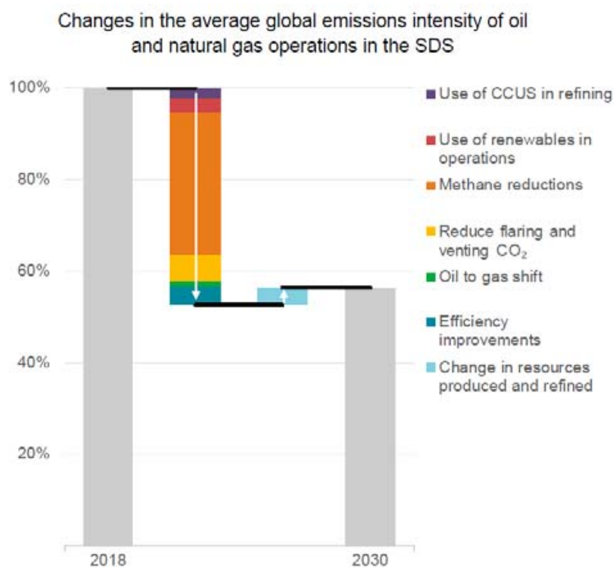
**Figure 8: Upstream Investment Under Sustainable Development Scenario**




Source: IEA

The more immediate implication is the need to reduce the emissions intensity of their own operations, which the IEA models at close to a 50% reduction by 2030 under the SDS:

**Figure 9: Changes in Global Emissions of Oil & Gas Operations**




Source: IEA

Most of the reduction in emissions intensity can be achieved through addressing methane emissions, along with reducing gas flaring and venting. Importantly, it can be accomplished with existing technologies and operational practices. The IEA estimates that 75% of global oil & gas methane emissions are avoidable today and could be reduced by one-third at zero net cost.[8] As the Agency describes it, reducing methane leaks to the atmosphere is the "single most important and cost-effective way" for the industry to reduce the GHG emissions associated with the process of getting oil and gas out of the ground to consumers.[9]

## Methane Emissions

Methane ($CH_4$) is the primary component of natural gas, the fuel that is often viewed as the bridge to a fully renewable future. When methane combusts, about half the energy comes from burning hydrogen that produces no $CO_2$, which is why natural gas is perceived to be the most environmentally friendly fossil fuel. However, when methane is emitted before it has a chance to be burned, it is remarkably effective at trapping heat. So adding a little more methane to the atmosphere can have a significant impact on the pace of global warming. Over a 20-year period, a kilogram of methane warms the planet as much as 80 times more than a kilogram of carbon dioxide. Since the Industrial Revolution, methane concentrations in the atmosphere have more than doubled, and scientists estimate that it is responsible for 20-25% of the global rise in temperature.[10] The EPA estimates that 50-65% of global methane emissions come from human activities, with 30% of those emissions attributable to the oil and gas industry.

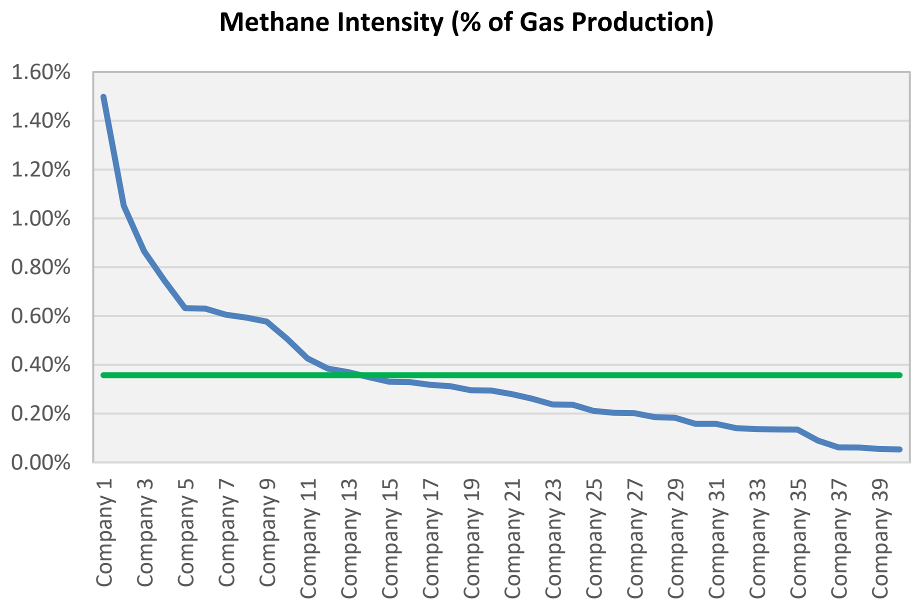
Unfortunately, the problem is likely even worse than those estimates suggest. There is plenty of room for error in inventory-based calculations as a typical well has 55 to 150 connections to equipment such as heaters, meters, dehydrators, compressors, and vapor-recovery units. Many of these have the potential to leak and many pressure relief valves are designed to purposefully vent gas.[11] A study by Alvarez et al, which was published in Science Magazine in 2018, combined ground-based measurements and aircraft to observe areas that comprise 30% of US gas production. They concluded that grossed up methane emissions are equivalent to 2.3% of total US gas production or 60% higher than the EPA estimates. But the disparity is even greater when looking at just the upstream production process where methane emissions were over 2x EPA estimates and accounted for 58% of the total across the oil and gas value chain. The authors attribute the considerable gap to the fact that "existing inventory methods miss emissions released during abnormal operation conditions." Even though the industry's contribution to global warming is likely worse than previously understood, there is cause for optimism if immediate action is taken. The study concludes that substantial emission reductions are possible through rapid detection of emissions events and the replacement of failure-prone systems while highlighting that since methane is removed from the atmosphere much more rapidly than $CO_2$, "reducing $CH_4$ emissions can effectively reduce the near-term rate of warming."[12]

Like most measures of environmental performance, the divergence between methane intensities of companies is significant. Part of that is attributable to calculation itself (some including gathering and processing emissions while some use both oil and gas production in the denominator). On a standardized basis of $CH_4$ emissions divided by gross operated gas production, the average intensity of

[8] https://www.iea.org/reports/methane-tracker-2020/methane-abatement-options
[9] https://www.iea.org/reports/the-oil-and-gas-industry-in-energy-transitions
[10] https://www.nationalgeographic.com/environment/global-warming/methane/
[11] https://link.springer.com/content/pdf/10.1007%2Fs10584-011-0061-5
[12] https://science.sciencemag.org/content/361/6398/186

US assets for the 40 public E&P companies we analyzed for 2018 was .36% with a wide range of .05% to 1.5%. Again, this is based on EPA reporting of inventory-based calculations and the top down study cited above highlights how actual methane emissions likely exceed these levels.

### Figure 10: US Public E&P Methane Intensity



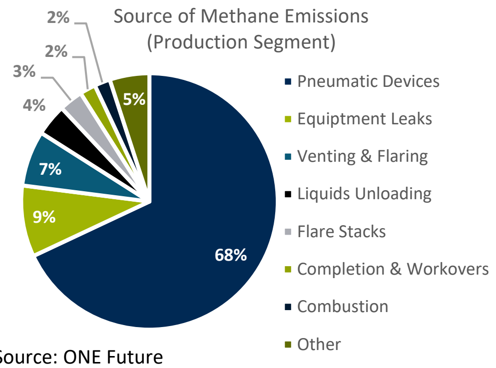

Source: EPA FLIGHT Data

Based on the number of companies across different basins that have already reached this threshold, Kimmeridge believes the entire industry should set a methane intensity target for US upstream production of below .2% by 2023.[13] For E&P companies with midstream assets the target could be increased to .25%. The additional .05% represents the emissions intensity for gathering and processing assets amongst ONE Future member companies.[14]

We also have a road map for the most direct path to meeting these targets, with the ONE Future alliance highlighting that 68% of the methane emissions in the production segment are attributable to pneumatic devices, while an ICF study commissioned by the Environmental Defense Fund identified the four major categories for potential methane emissions reduction.[15]

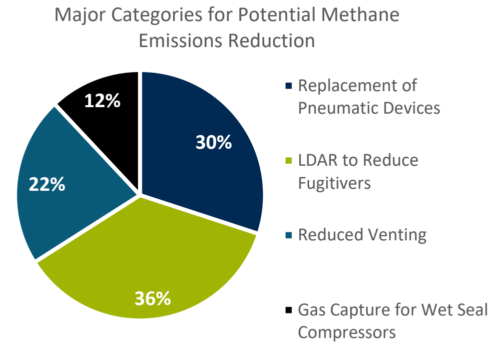
[13] Methane intensity % is calculated as (tonnes of methane emissions)/ ((total gas produced)*(85 mol%)*(methane density of .0192 kg/scf)*(1000 scf/mscf)*(1 tonne/1000 kg)).
[14] http://onefuture.us/wp-content/uploads/2019/11/ONE-Future-2018-Final-Report-LN.pdf
[15] https://www.edf.org/icf-methane-cost-curve-report

### Figure 11: Sources of Methane Emissions




Source: ONE Future

### Figure 12: Methane Reduction Categories




Source: EDF

Below we outline the specific steps companies should take to address the three most significant sources of methane emissions.

1) **Comprehensive, High Frequency Leak Detection and Repair (LDAR)**
Companies should employ existing and emerging technologies to collect emissions and operational data. This allows operators to detect malfunctions that release fugitive emissions while improving operational efficiencies. Leak detection itself can take many forms. The industry historically relied on optical gas imaging (OGI) infrared cameras, but companies are increasingly piloting the use of drones. BP highlights how drone-mounted leak technology in their US operations allows for up to 1,500 well sites to be surveyed every month for around $40 per well.[16] A recent study offered empirical evidence of the effectiveness of LDAR programs at reducing long-term leakage by quantifying emissions at 36 unconventional liquids-rich natural gas facilities in Alberta. A subset of those facilities was visited twice by the same detection team with an initial survey and a post-repair re-survey occurring 6 to 24 months after the initial survey. Overall, total emissions reduced by 44% after one LDAR survey, combining a reduction in fugitive emissions of 22% and vented emissions by 47%. Furthermore, over 90% of the leaks found in the initial survey were not emitting in the re-survey, suggesting high repair effectiveness. However, fugitive emissions reduced by only 22% because of new leaks that occurred between the surveys. The authors concluded, "this indicates a need for frequent, effective, and low-cost LDAR surveys to target new leaks."[17] Additionally, research cited by both Colorado and the EPA indicates that more frequent inspections result in greater reductions (80% monthly, 60% quarterly and 40% annually[18]), which supports Kimmeridge's view of the need for quarterly inspection of all sites.

[16] https://www.bp.com/en/global/corporate/news-and-insights/press-releases/bp-north-sea-deploys-mars-technology-in-world-first-methane-monitoring-project.html
[17] https://iopscience.iop.org/article/10.1088/1748-9326/ab6ae1
[18] https://www.edf.org/icf-methane-cost-curve-report

**Figure 13: Infrared Detection of Vented Gas**

Vented Gas from Oil Storage Tank Visible through Infrared Camera

Source: EPA.

**2) Site Centralization and Electrification**

A major component of remote automation of oil and gas sites is the operation of control valves, which are often powered and actuated by natural gas through pneumatic controllers. Several types of these equipment release or "bleed" natural gas to the atmosphere by design. In addition to emissions by design, a large fraction of total emissions from pneumatic devices in the production segment are due to a defect or maintenance issue.[19] EOG identified high-bleed pneumatic controllers as the largest source of methane emissions in their operations and during 2018 they saw a 45% reduction in methane emission intensity as a result of their initiative to retrofit or remove them. As companies increasingly outline their plans to phase out high-bleed controllers, the larger potential opportunity for methane emissions mitigation is the centralization and electrification of production sites. Electricity can be used to power instrument air controllers where compressed air is substituted in place of natural gas, thus eliminating methane emissions entirely. Electric, zero emission alternatives for controllers and engines are most feasible in centralized sites, which also allow for more cost-effective monitoring and deployment of emission reduction technology.

- Conoco has removed or replaced all their high-bleed pneumatic controllers in the lower 48 while many of their new facilities include devices to use supplied air instead of site gas to reduce natural gas emissions from pneumatics.
- XTO committed to a three-year plan in 2017 to phase out 1,250 high-bleed pneumatic devices on facilities across their U.S. assets and is committing to employ better technology solutions, such as lower-emitting devices and instrument air for new construction.
- Noble utilized technology at their Mustang CDP in Colorado to reduce emissions by 90% through the electrification of engines, the use of compressed air for pneumatic controllers, the elimination of tanks from the production location and the elimination of truck loading.

[19] https://www.ccacoalition.org/sites/default/files/resources/2017_OGMP-TGD1-Pneumatic-controls-and-pumps_CCAC.pdf

**3) Reduced Venting**

The process of producing oil and gas results in the venting of a portion of the natural gas. Recovery of the vented gas increases revenue while reducing emissions. A Vapor Recovery Unit, or VRU, is a compression system used to collect and compress low volume gas streams for injection into a larger compressor or directly into a gas gathering line. While some states already require the use of VRUs, we believe this should be a universal practice across US oil and gas operations. Many companies have already announced their plans and the industry must provide increased disclosure around the use of vapor recovery units.

- For Diamondback, every facility built since 2014 features vapor recovery towers and vapor recovery units.
- Over 90% of Parsley's production flows through facilities with a VRU and has implemented a plan to install them on all new ones.
- In 2019, Noble recovered more than 2.6 billion cubic feet of methane through new VRUs in the U.S.

One significant source of methane venting is associated with planned "blowdowns." In mature wells the accumulation of liquids, primarily formation water, can impede the flow of gas. When this occurs the removal of fluids ("liquids unloading") is required in order to maintain production. Shutting in the well to allow bottom hole pressure to increase, then venting the gas into the atmosphere is referred to as "blowing down the well." Conversely a plunger lift system uses the well's own energy to lift liquids from the tubing, which often minimizes and sometimes eliminates the need for blowing down the well[20]. Range Resources highlighted in their 2020 Sustainability Report that they expect the installation of plunger lift technology to yield a 95% reduction in methane emissions by the end of 2020 while increasing revenue by $25M. Blowdowns also occur when compressors are periodically taken offline for maintenance, operational standby or emergency shutdown testing. When compressors are shut down, typically the high-pressure gas remaining in the units and associated piping is vented to the atmosphere. The EPA has noted that simple changes in operating practices can save money and significantly reduce methane emissions. These include keeping compressors pressured when they are off-line and connecting blowdown vent lines to the fuel gas system to allow the normally vented gas to be used while the compressor is off-line.[21]

## Gas Flaring

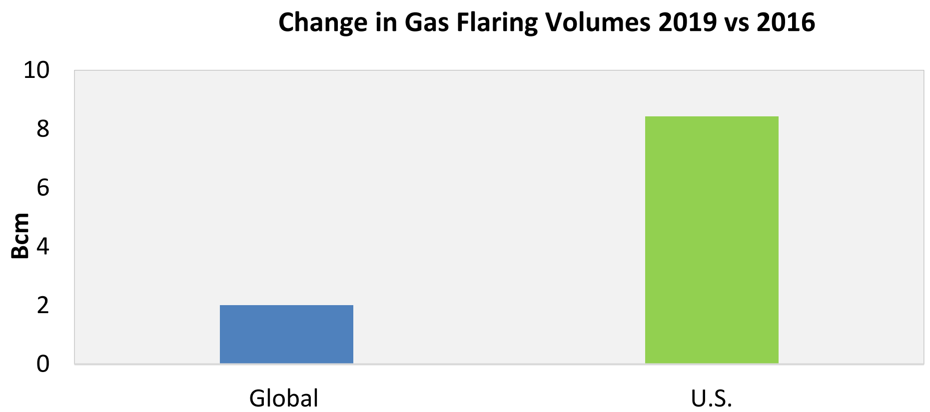
As investors in the US E&P sector, another area where we can have an outsized impact on the environment is by addressing gas flaring. Flaring is the controlled release and burning of natural gas during production and processing operations. Sometimes flaring can be required to safely dispose of gas released during process upsets or other unplanned events, but routine (or non-emergency) flaring happens during normal oil production operations in the absence of adequate takeaway capacity. It is unnecessary, wasteful and typically a result of poor planning or a lack of redundancies in the system. It is also a significant source of methane emissions due to malfunctioning units or unlit flares. A study

[20] https://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-liquids-unloading.pdf
[21] https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/ll_compressorsoffline.pdf

conducted by the Environmental Defense Fund across hundreds of flare stacks across the Permian Basin found that 11% of flares in the Permian were either unlit or malfunctioning, which led to the prediction that 7% of flared gas is emitted unburnt. That rate is 3.5x greater than the EPA assumption of 98% combustion efficiency. [22]

The World Bank estimates that in 2019 over 400Mt of emissions ($CO_2e$) were released from flaring, while satellite data shows that flaring is at its highest level in a decade at 150 billion cubic meters per year. This was 3% higher than 2018, with the US responsible for two-thirds of that increase after rising by 23%.[23]

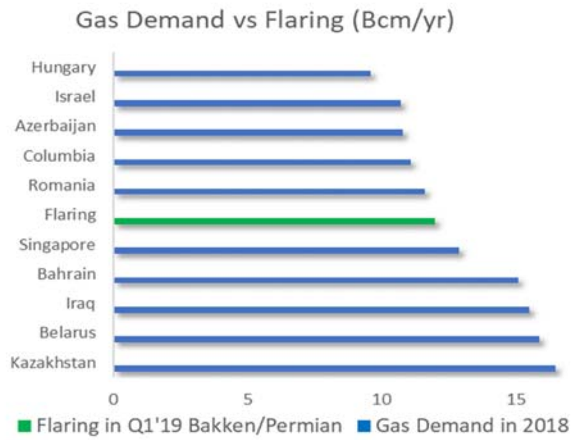
### Figure 14: Global and US Change in Flaring Volumes, 2019 vs 2016




Source: World Bank

To frame the magnitude of the problem, it is helpful to compare the level of flaring in the Permian and Bakken to the total annual gas demand in certain countries:

### Figure 15: Gas Demand vs Flaring, by Country

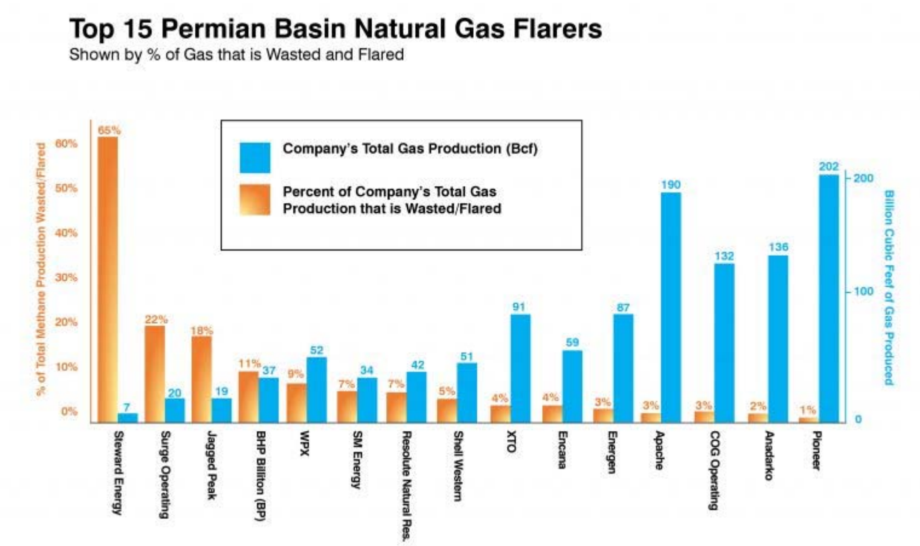



Source: Rystad

[22] https://www.permianmap.org/flaring-emissions/
[23] https://www.worldbank.org/en/news/press-release/2020/07/21/global-gas-flaring-jumps-to-levels-last-seen-in-2009

In 2018, close to 4% of all the gas in the Permian basin was flared with significant dispersion amongst operators. Of the roughly 700 individual operators in the region, 32 flared 100% of their produced gas, 41 flared over 60% and 66 flared over 20%.[24] Notably, many of the largest producers were already well below the basin average. This is one of the reasons Kimmeridge has previously argued that industry consolidation is environmentally beneficial. Larger scale provides the financial resources necessary to improve a company's environmental footprint and we consistently see a meaningful inverse correlation between the size of operations and emissions intensity. One example would be Parsley Energy's acquisition of Jagged Peak, a private operator that flared over 20% of its gas volumes in 2019, where Parsley claims to have reduced flared volumes by almost 90% as of August 2020. Another example of this is EOG's investment in technology to minimize flaring associated with unpredictable downstream market interruptions. As noted on their second quarter earnings call, "we tested a new EOG innovation we have named closed-loop gas capture. Closed-loop gas capture is an automated process developed in-house to reroute natural gas back into existing wells when a downstream interruption occurs. Initial results were successful and indicate that our closed-loop gas capture process has the potential to both reduce flaring and return the majority of the captured gas from the well back to production."

**Figure 16: Top 15 Natural Gas Flarers in the Permian Basin**




Source: EDF

While flaring levels may recede through 2021 from reduced drilling activity and the completion of infrastructure projects like the Permian Highway pipeline, the industry and regulators need to adopt more rigorous standards to structurally reduce flaring intensity. Regardless of the regulatory environment, operators should commit to zero routine flaring by 2025.

## Energy for Extraction

While the simplest and most cost-effective path to upstream emissions reductions is through reducing methane intensity and eliminating flaring, it is also important to address the energy consumed in producing oil and gas. This is essentially the combustion associated with compressors, engines, turbines,

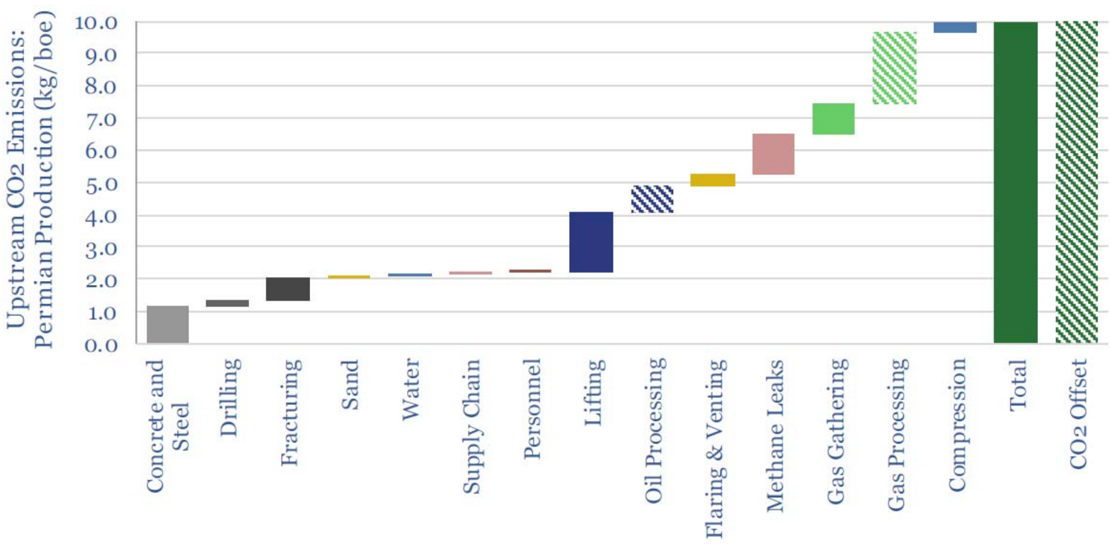
[24] http://blogs.edf.org/texascleanairmatters/2019/08/14/new-permian-data-show-how-worst-offenders-prevent-progress-on-flaring/

heaters, etc. For a US shale producer there is a significant amount of diesel consumed to fuel drilling rigs (60-80 gal/hour), frac spreads (1,000 gal/hour[25]) logistics transportation (8k truck trips and 350k miles per well[26]) and decentralized generators. The future of US unconventional development is going to require electrification, particularly to address the considerable compression required for sustaining production operations. The leading shale companies are already preparing. As EOG highlights in their sustainability report, "to address our growing use of compression equipment and the resulting emissions, we plan to initiate a pilot project in the second half of 2019 that will combine solar and natural gas to generate electricity to power compression equipment. In addition, we expect to expand our use of electric hydraulic fracturing fleets (e-fracs). We believe e-fracs and the solar project have the potential to significantly reduce our combustion emissions intensity rate in the future."[27]

## 50% Reduction in Emissions Intensity & Charting a Path to Net Zero

In June 2020, the Industry body Oil and Gas UK (OGUK) published a report titled, The Pathway to Net Zero: Production Emissions Targets, which outlined aspirational targets of a 50% reduction in the GHG emissions arising from exploration and production activities on the UK Continental Shelf by 2030, delivering a 90% emissions reduction by 2040 and a path to net zero by 2050.[28] Notably these are absolute targets as UK production is expected to decline considerably over the next several decades. However, we think the US oil & gas industry can replicate or even exceed these targets on an intensity basis. Using the Permian as an example, the average upstream intensity in 2019 is estimated at 22kg/BOE or 27kg including gathering and processing. A study by Thunder Said Energy highlights how two-thirds of those emissions are attributable to the issues discussed in this report: flaring, venting and methane leaks.

**Figure 17: Upstream $CO_2$e by Stages of Production in the Permian**



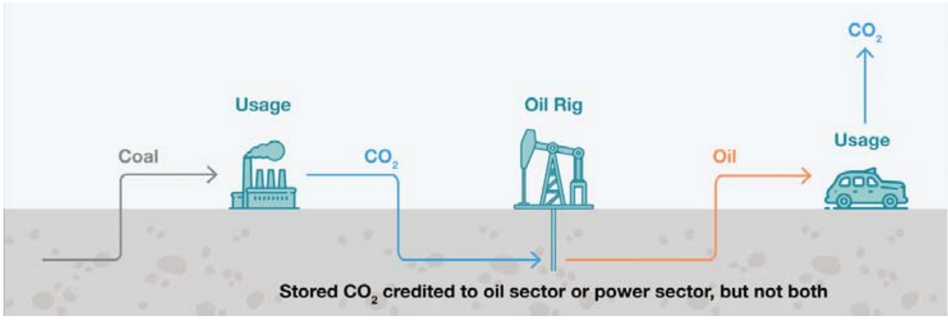

Source: Thunder Said Energy

[25] https://www.hartenergy.com/exclusives/reducing-opex-dual-fuel-hydraulic-fracturing-operations-181661
[26] https://thundersaidenergy.com/2019/12/08/shale-growth-what-if-the-permian-went-co2-neutral/
[27] https://www.eogresources.com/wp-content/uploads/2019/09/Sustainability-Report-2018.pdf
[28] https://oilandgasuk.co.uk/wp-content/uploads/2020/06/OGUK-Production-Emissions-Targets-Report-2020.pdf

The study illustrates how an ideally managed Permian producer should be under 7kg/BOE (10kg with gathering and processing) while laying out the path to net zero. First by reducing flaring to .25%, emissions would be cut by 3.5kg/BOE. Reducing methane intensity from .7% of gas to .2% of gas production would cut emissions by 2.5kg/BOE. The third largest contributor is the energy required for pumps to help lift the oil out of the ground. If the pumps are powered by diesel this could contribute 2-5kg/BOE of emissions, but the study concludes this could be halved through the application of digital technologies to optimize lifting and improve efficiencies.[29] Most of the other categories can be addressed through electrification and improved supply chain management.

The critical question associated with the concept of net zero is how to address the remaining 7-10kg/BOE. Outside of purchasing carbon offset credits today, the most promising opportunity is Enhanced Oil Recovery (EOR) using $CO_2$ reinjection into depleted shale wells. But as the IEA highlights there are currently obstacles to $CO_2$ injection driving net zero emissions. Right now, the majority of $CO_2$ injected in $CO_2$-EOR projects is produced from naturally occurring underground $CO_2$ deposits. This is due to the absence of available $CO_2$ close to oil fields while "using natural sources provides no benefit in terms of the emissions intensity of the produced oil". In the United States, more than 70% of the $CO_2$ injected today for $CO_2$-EOR is from natural sources. There are a few projects that use $CO_2$ captured from anthropogenic sources for EOR like the Century and Petra Nova plants in Texas. But an important issue becomes who claims credit for the avoided $CO_2$ emissions? Under current regulations, a credit associated with storing $CO_2$ underground can only be counted once: either it reduces the emissions from the original source when it was captured, or it can reduce the emissions from oil production. In the example the IEA provides, a capture unit is attached to a coal-fired power plant and the captured $CO_2$ is transported to and injected in a $CO_2$-EOR site. Currently it is not possible for both the electricity generated to be low-carbon and for the EOR production to be low-carbon. "To put this another way, if a coal-fired power plant operator were to pay a $CO_2$-EOR operator to store captured $CO_2$, the $CO_2$-EOR operator could not claim that the oil produced has negative emissions."[30]

### Figure 18: Pathway of Stored $CO_2$




Source: IEA

But emerging technologies around Direct Air Capture (DAC) may provide the solution. Both Oxy Low Carbon Ventures and Chevron Technology Ventures have invested in Carbon Engineering's direct air

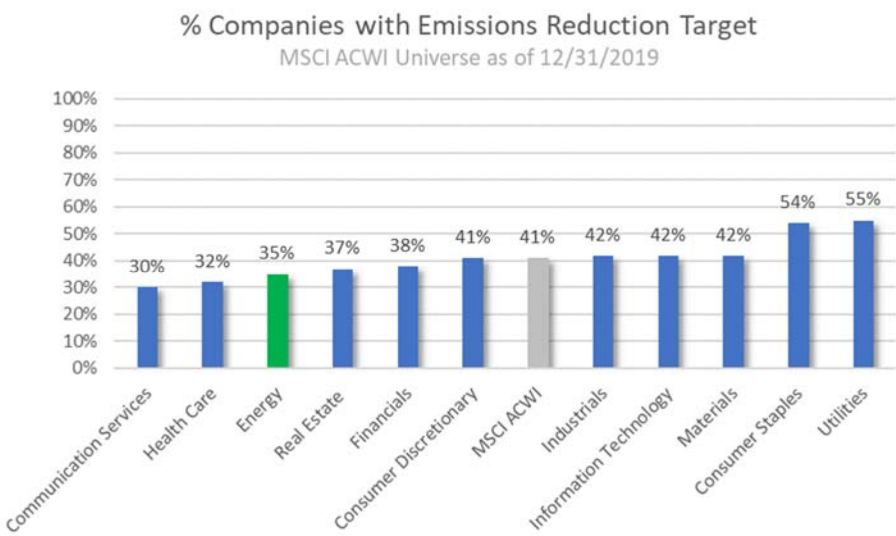
[29] https://thundersaidenergy.com/2019/12/08/shale-growth-what-if-the-permian-went-co2-neutral/
[30] https://www.iea.org/fuels-and-technologies/carbon-capture-utilisation-and-storage

capture technology that captures carbon dioxide directly from the atmosphere and converts it into low-carbon fuels for transport and for use in enhanced oil recovery. Furthermore, OXY and Carbon Engineering announced in 2019 that they are jointly proceeding with the engineering and design of the world's largest and Direct Air Capture sequestration facility. The proposed project will start with one DAC plant located in the Permian basin that captures 500 kilotonnes of atmospheric $CO_2$ per year and is expected to expand to include multiple DAC plants, each capable of capturing one megatonne of atmospheric $CO_2$ annually. If approved, construction is expected to begin in 2021 with startup two years later. "Pairing DAC with $CO_2$ sequestration in EOR operations is a significant step forward for the energy industry, as it provides a mechanism designed to greatly reduce or fully eliminate the net addition of $CO_2$ to the atmosphere from oil production and use."[31] While zero net emissions may not be feasible today, we think a target of a 50% reduction in emission intensity by 2030 is an obtainable goal while the industry progresses the commercialization of net zero solutions.

## Operator Targets and Reporting Disclosures

While CEOs have clearly become more ESG literate and public companies often have a slide in their presentation deck that references environmental performance, very few have emission reduction targets. Specifically, only 35% of global Energy companies had a confirmed emission reduction target at the end of 2019.

**Figure 19: Companies with Emissions Reduction Targets, by Sector**




Source: Morgan Stanley

Given the scrutiny that the industry faces regarding its contribution to climate change, Kimmeridge believes that every public Energy company should set emission reduction targets that are aligned with the Paris Agreement. They should be realistic targets that can be accomplished during the average tenure of a company's director. The industry cannot simply resort to 2050 "hero statements" that lack accountability. Along with accountability the industry needs credibility. The challenge companies face in

[31] https://www.oxy.com/News/Pages/Article.aspx?Article=6095.html

setting emissions targets is the lack of transparent, reliable data accompanied by detailed disclosure. From that perspective, it is important to reiterate the inherent shortcomings associated with factor-based inventory estimates. These are engineering calculations based on which type of equipment is utilized in the field, which may or may not reflect actual operational performance. What is particularly worrisome is that companies are now introducing factor-based emissions intensity targets into their short-term incentive compensation metrics. Executives are getting paid on internal calculations without third-party verification or any indication of how they relate to observable atmospheric readings. Investors should be wary of rewarding companies for adopting these metrics without clear evidence of how it is driving an improved environmental outcome for society. To build credibility with the investment community around their environmental strategy, companies should:

1) Disclose the specific actions being taken to meet intensity reduction targets (scope and frequency of LDAR program, replacement of pneumatic devices, installation of VRUs, use of plunger lift, field electrification, etc.)
2) Outline the steps being taken to monitor the effectiveness of flare units and ensure zero flaring by 2025
3) Increase independent monitoring and verification of atmospheric readings with transparency into how it correlates to internal calculations
4) Provide independent certification of emission intensity (i.e. Intertek's CarbonClear), especially if linked to executive compensation
5) Aspire for continuous on-site emissions monitoring as the technology improves and costs are reduced

We believe this should all be disclosed in the context of the Task Force on Climate-related Financial Disclosure (TCFD) reporting principals and Sustainability Accounting Standards Board (SASB) standards. The Task Force was established in 2015 by the Financial Stability Board following a request by the G20 in order to provide a set of recommendations to allow for "consistent disclosures that will help financial market participants understand their climate-related risks."[32] The 11 TCFD recommendations are high-level principles that are complimentary with the SASB Standards, which provide detailed disclosure topics and metrics for specific industries. Even though over 600 organizations have expressed support for the TCFD, implementation of their recommendations has been slow. In their 2019 Status Report the TCFD reviewed over 1,000 company climate-related disclosures and found that only 25% disclosed information aligned with more than 5 of their 11 recommended disclosures and only 4% made disclosures aligned with 10 of the 11. The TCFD highlights the importance of viewing the 11 recommended disclosures holistically and notes "for a company to effectively tell its story of how it is managing climate-related risks and opportunities, it requires disclosures across all four core elements of the TCFD."[33] We think this is no longer going to be deemed acceptable by the investment community. Blackrock's CEO Larry Fink made the public request in January that companies should both publish a disclosure in line with industry-specific SASB guidelines by year-end and disclose climate-related risk in line with the TCFD's recommendations. He stated that in the absence of robust discloses Blackrock "will increasingly conclude that companies are not adequately managing risk."[34] Kimmeridge recommends

[32] https://www.fsb-tcfd.org/wp-content/uploads/2017/06/FINAL-2017-TCFD-Report-11052018.pdf
[33] https://www.cdsb.net/tcfd-good-practice-handbook
[34] https://www.blackrock.com/corporate/investor-relations/larry-fink-ceo-letter

that E&P companies align their reporting with SASB standards and adopt all 11 TCFD recommended disclosures by 2022.

## The Role of Governance

The greatest impediment to an improvement in the environmental performance of US E&P companies is the misalignment of interests where management teams and boards continue to be compensated for maintaining the status quo.  Improving governance and alignment is essential for changing industry behavior. The continued reliance on relative total shareholder return within a narrowly defined peer group of similar E&P companies does not properly incentivize management teams to evolve their business to meet the challenges associated with the energy transition. We also believe that the dynamic set of risks related to the energy transition are best addressed through greater diversity of perspectives. Unfortunately, E&P board rooms are quite insular. Wolfe Research analyzed the 224 directors within their US E&P coverage and found that 71% are former or current Energy executives.[35] For an industry that lacks experience with disruption at this scale and is often skeptical of climate related risks, there is an increased need for external perspectives. A strong, independent board should take ownership of setting climate-related goals that are fully integrated into the planning process and accompanied by transparent disclosure to investors. Ultimately the board of directors must hold the CEO responsible for the environmental performance of the company.

## Conclusion

As long-time investors in the Energy sector, we have observed two consistent characteristics of the E&P industry. First, their actions are heavily influenced by peer behavior and second, they have an unparalleled ability to exceed expectations when they are properly incentivized to drive a particular outcome. If the Industry can harness the same ingenuity and determination that led the US to become the largest oil producer in the world towards their environmental performance, society will benefit. In order to do its part in mitigating climate change the oil and gas sector needs to reduce its own emissions by 3.4Gt $CO_2e$ by 2050, a 90% reduction from current levels. McKinsey estimates that 1.5Gt, or a little less than half of that reduction target can be accomplished by reducing fugitive emissions and flaring for a cost of less than $15/tonne.[36] That cost is likely significantly less onerous than any potential carbon tax the industry will be facing in the future. It is not only about doing what is right for society, it is prudent financial risk management. However, investor pressure is required to ensure management teams understand the urgency with which they must address the risks associated with the energy transition.

[35] A Guide to E&P Boards, Josh Silverstein Wolfe Research August 2020
[36] https://www.mckinsey.com/industries/oil-and-gas/our-insights/the-future-is-now-how-oil-and-gas-companies-can-decarbonize