KIMMERIDGE Energy

Great Expirations and the Myth of the Land Grab

February 2014

Introduction

It is common wisdom among energy investors that the "land grab" is over in the E&P space and that all the prime positions in unconventional plays have been leased. This view fails to capture the fact that leases are in fact finite term contracts and that while leases that have been drilled become held by production (HBP), a large percentage of all acreage expires undrilled at the end of its term, to be recycled and leased again by the next operator. This wouldn't be much of a concern if E&Ps tended to lease exactly the amount of acreage that they need, but as we will demonstrate below, their approach is far less disciplined.

How a Lease Works

Prior to disaggregating the data on leases, it is first worth understanding the key constituents of an oil and gas lease. In the US, ownership of minerals was originally granted along with ownership of surface rights, but over time ownership of minerals in many areas has been severed from ownership of the surface. To lease lands for oil and gas, an operator needs to make a deal with the mineral owner only, since local statutes generally give mineral owners (or leaseholders) the right to access their minerals. Minerals can be owned by governments, by corporations, or by individuals, and in the industry leases are thought of in three categories:

- Federal lands – these are particularly common in the western US, where the federal government remains a major landowner
- State lands
- Fee lands, where individuals own the minerals.

Note: In many states there are lands under which portions of the minerals are owned by federal or state governments and portions are owned by individuals

While lease forms vary with any two parties free to draw up any contractual arrangement they choose, most fee leases are modeled off standard forms issued by the AAPL (American Association of Petroleum Landmen). In contrast, state and federal lease forms tend to be fixed and offered through auctions. As such, most leases contain the following key terms:

- **Lease (bonus) payment:** How much cash will be paid upfront per acre of net mineral rights leased
- **Royalty:** What percentage of revenue will be paid to the landowner and on what basis
- **Extension(s):** Whether the primary term of the lease can be extended by another lump sum payment and how much that payment would be
- **Term:** Time period covered by the lease, which is usually broken down between the primary and the extension period (common examples are 5+5, 5+3 or 3+2)
- **Pooling:** How the acreage can/ may be pooled into larger drilling units
- **Shut-in payments:** How much will be paid in the event the well is temporarily shut-in and how long this can occur prior to the lease forfeiting HBP status
- **Spacing:** Definitions of what acreage a single well will hold within the leasehold (usually a function of state rules and depth)
- **Other terms:** Often there are additions to leases to govern rules around surface access, crop damage, water rights, etc.

Of the terms to negotiate, bonus, term and royalty are by far the most critical. Price and royalty tend to rise as a play concept is de-risked and term shortens. As a result, in hot areas of high activity and early production such as the Eagle Ford, leases have been known to be as short as two years with $30,000/acre paid upfront and 25-30% royalty. In contrast, first movers in yet unproven plays, like Kimmeridge in Illinois, can pay as little as $50/acre for a 5+5 (10-year) lease with a 12.5% royalty.

To put the impact of this in perspective, consider an early mover and a late mover in the same area, each acquiring a square mile section, or 640 acres. This example (see Exhibit 1) assumes the acreage initially acquired is comparable in geologic quality, but also shows the impact if the geology varies in the final column. For the early mover (Company A) price ($250/acre) and royalty (12.5%) are low, while term is long. In contrast, Company B has to pay up to get in in the form of a higher bonus ($10,000/acre) and royalty (25%) and shorter duration with the consequence that in the first five years it effectively pays double to hold the land through the primary lease term and renewal.

As a result, Company B already has $6.4M in the ground prior to drilling and by the end of the five years $12.8M, assuming the entire block requires renewing and is not HBP after three years, versus just $0.16M for Company A. Even assuming a four-well program and $5M per well, this is a significant drag on overall finding & development cost (F&D). Even assuming comparable geology, Company A would report F&D of $23/bbl versus $41/bbl for Company B. Furthermore, if the geology is marginally worse for the late entrant, this balloons to $54.5/bbl or over 2X the early mover.

	Company A Early mover	Company B Late mover	Late mover (poor acreage)
Price per acre $	250	10000	10000
Acreage	640	640	640
Total initial cost $M	0.16	6.4	6.4
Duration (yrs)	5	3+2	3+2
Cost over 5 years $M	0.16	12.8	12.8
Drill Cost $M (per well)	6	6	6
Well spacing	160	160	160
Wells per 640	4	4	4
EUR (mmboe)	300	300	225
Royalty %	12.50%	25%	25%
Net EUR (mmboe)	263	225	169
Total costs $M	24.16	36.8	36.8
F&D (drilled over 10 years)	**23.0**	**40.9**	**54.5**

Exhibit 1: Comparison of an early and late mover in an unconventional play

Given the above, it seems reasonable to believe that operators and investors alike should keep a close eye on average lease duration, how much capital is required to hold non-HBP acreage and how much capital employed is tied up in holding the unproven land position.

What Expires When? A Review of the Large-Cap E&Ps

While theoretically simple to understand, in the real world the decisions between price, geology and term present a constant trade-off. On the one hand, if you own a large position in an unconventional play, the cost of de-risking is spread over a larger acreage position; spending $5M to de-risk 50,000 acres is better than spending $5M to de-risk 5,000 (the latter implies 10X F&D). More acreage is beneficial if the play proves commercial and land/lease prices rise. In contrast, land that you can neither sell nor drill before the term expires is a drag on returns since it is a depreciating asset without terminal value. Further complicating the situation is the fact that unconventional plays are rarely uniform and the core of the play is difficult to identify prior to drilling. Pre-delineation, a certain geographic spread is beneficial to avoid being in the right zip code but on the wrong street, while paying up for the core, once the core is well defined, can often make economic sense.

The amount of land acquired is also directly proportional to both the number of geological play concepts on the acreage and the size of the prize, typically measured as oil or gas in place per section. For example, in the Permian if a horizontal well de-risks 1 Wolfcamp location with 650,000 barrels of estimated ultimate recovery (EUR) and you can drill four wells in any single 640-acre section, then even at $10,000/acre the acreage cost per barrel is just $2.46. Furthermore, if there is a secondary stacked play (Wolfcamp B) this falls to $1.23/barrel upon success. In comparison, in the Mississippi Lime where the average well may recover 360,000 barrels and there are limited stacked pays, the acreage cost per barrel could be $4.44, a significant impact on the overall F&D cost. Costs for the land should also be proportional to the cost of drilling, since in a successful play there is usually a correlation between well cost and resource size (higher well costs require higher EURs). These factors mean it is challenging to determine any "model" solution to how much acreage an operator should hold. However, it does not preclude some common sense conclusions.

Peer group				
Market Cap $M	337,143		Expirations ('12-'15)	23,362,920
Net Debt $M	99,374		2013	8,248,366
EV $M	436,516		2014	7,921,198
Net Acreage	83,755,272		2015	7,193,357
Net Undeveloped	54,920,812		Expirations 2013%	15%
(Net) Wells	158,624		Expirations 2014%	14%
Gross Wells	261,593		Expirations 2015%	13%
Unproven acreage%	66%		sum of 3-yr%	43%
Net to gross productive wells	61%		Capitalized unproved $M	24,170
2012 wells drilled (net)	9223		Unproven per acre	440

Exhibit 2: Key statistics for the consolidated peer group

As a sense check, consider the mid- and small-cap E&P peer group* as a whole. If the peer group of E&Ps consisted of a single company, it would have a market cap of $337 billion, an enterprise value of $436 billion, and would hold leases on 83.7 million acres. This is nearly equivalent to the entire state of Montana. Of this acreage 54 million acres (the size of Minnesota) are undeveloped, and 23.3 million acres will expire between 2013 and 2015, equivalent to the state of Indiana. If, on average, drilling a well would hold 160 acres, then it would take a staggering 146,000 wells or 16X the number of wells these companies drilled in 2012 to convert that 23.3 million acres to held by production. At $5M per horizontal well this would amount to $730 billion of capex over three years (over twice the aggregate market cap), with another $986 billion (nearly double the 2013 US fiscal deficit) required to hold the remaining unproven acreage.

Over the last four years, we have heard the argument that it is better to drill than write-off leases. While not quite so disturbing, the peer group has over $24Bn of capital (at $440/acre) tied up in unproven acreage with 43% of this expiring between 2013 and 2015 (worth $3.4 billion per year). It is arguable that drilling wells that lose less than $3.4 billion a year and hold some of this acreage is accretive but only due to the over-leased position that these companies have put themselves in. Given that the peer group trades at an average P/BV multiple of 1.5X this also implies that the expiration of leases would be a 10-11% drag on the peer group's share performance over the three-year period, versus drilling and in some way maintaining the book value at the expense of returns. Ultimately however, huge amounts of acreage will expire undrilled, which will benefit the mineral owners who can re-lease acreage that has expired to new operators.

**The 43 E&P's include: AR, AREX. BBG, CHK, CLR, COG, CRK, CRZO, CWEI, CXO, DNR, DVN, EOG, FANG, FST, GDP, LPI, KWK, MHR, MRO, MTDR, MUR, NBL, NFX, OAS, PDCE, PQ, PVA, PXD, QEP, ROSE, RRC, SD, SFY, SGY, SM, SWN, UPL, WLL, WTI, XCO, XEC*

It is evident that not all E&Ps and their management teams are equally over-leased. Looking at upcoming expirations it is clear that Sandridge, Comstock, Laredo, Penn Virginia, Approach and Goodrich are all under considerable lease pressure – they each have over 75% of their acreage expiring within the next three years. We have also considered (see Exhibit 4) how many years it would take to drill all of each company's undeveloped acreage. While Laredo (eight years), Comstock (nine years) and Approach (11 years) all have low inventories relative to drilling activity, Sandridge (113 years) is at the opposite end of the spectrum. In fact, while Laredo appears to have a challenge based on the amount of wells required to hold the acreage assuming 160-acre spacing, the company can be expected to convert all acreage to HBP because it is growing very rapidly. Another standout is Quicksilver who has 49% of its leases expiring in the next three years, but based on recent drilling rates would require 127 years to convert the unproven acreage to HBP. Southwestern would require 100 years, Devon 64 years and Chesapeake 45 years. Amongst the oilier names, the issue is less pronounced. However, Clayton Williams has 43% of its unproven acreage expiring in the next three years and 30 years worth of drilling, along with Carrizo (68%, 42 years), Marathon (73%, 19 years) and W&T Offshore (70%, 43 years).

KIMMERIDGE Energy

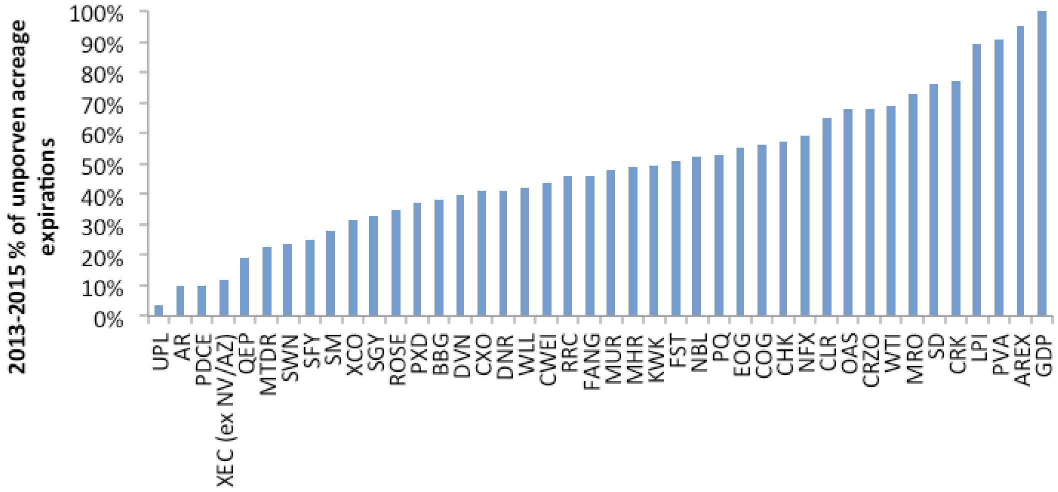


Exhibit 3: Percentage of unproven acreage expiring 2012-2015

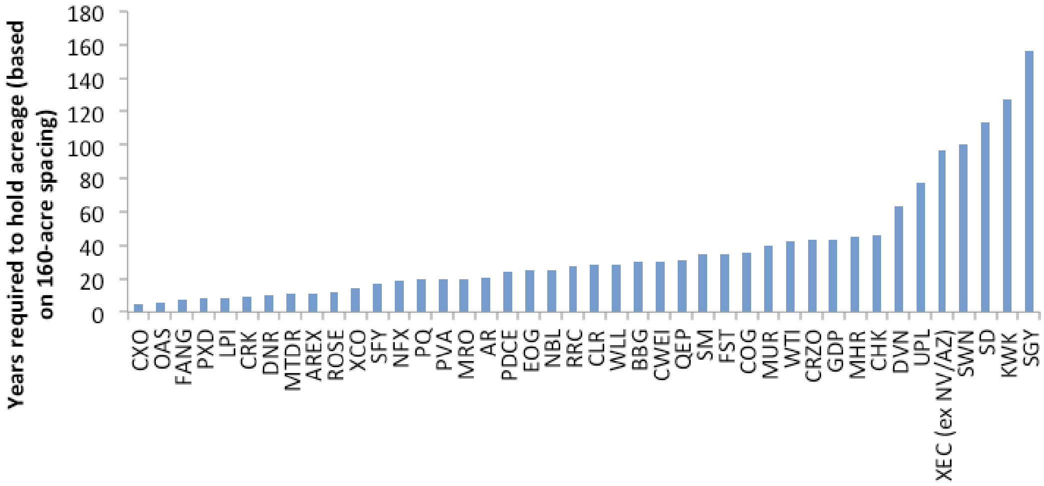


Exhibit 4: Years to hold acreage based on 160acre spacing and 2012 well count

While having a significant acreage base that is expiring is clearly an issue, the severity of the problem depends in part on the original cost per acre. If an operator is in a position to lease in the core of a play early at low cost, then the impact of over-leasing is less severe. Good examples of this include Southwestern whose average capitalized cost per acre is $94, and Clayton Williams ($97/acre). On the other hand, there are companies like Penn Virginia with an average capitalized cost of $426/acre, Comstock ($1,165/acre), Forest ($653/acre) and Marathon ($2,631/acre), which incidentally also has almost 20% of its capitalized costs in unproven acreage. On this latter metric of unproven acreage as a percentage of total capitalized costs, chief offenders include Antero (42%), Magnum Hunter (37%) and Chesapeake (23%).

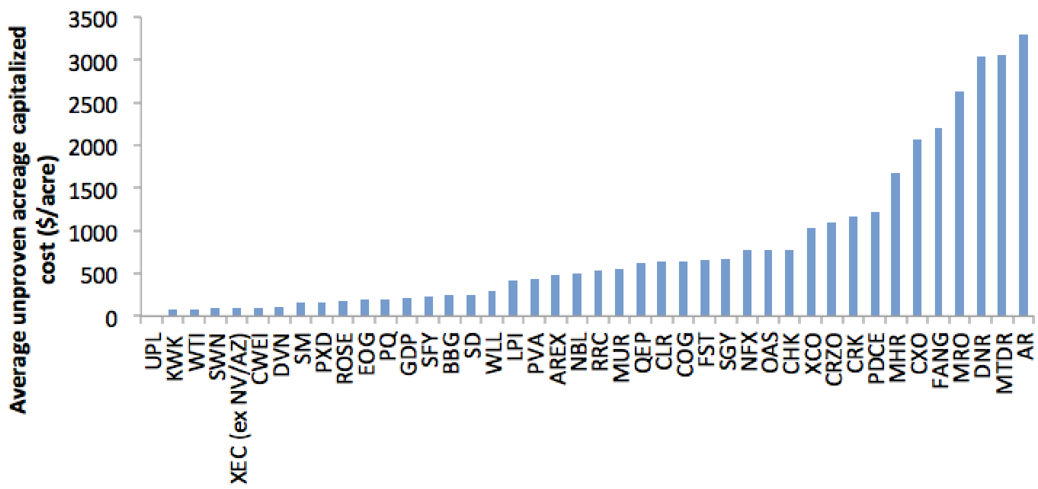


Exhibit 5: Capitalized unproven acreage cost ($/acre)'

Note: UPL has $0/acre due to the company writing off the value of its entire land base

EOG Versus Chesapeake: The Value of a Limited Land Position

Consider two well-known unconventional companies: EOG and Chesapeake. The reason this comparison is so important is because there is a perception amongst investors, or at least there was, that Chesapeake and Aubrey McClendon were successful land flippers, based on the number of announced joint ventures (JVs) and farm-ins. However, the data shows a different story and highlights the dangers of announcing your wins and not disclosing your losses.

EOG has been one of the best performing large-cap E&Ps over the last five years (+176%), while Chesapeake has been significantly less impressive (+33%). EOG is well known to be concentrated, disciplined and return-focused. Unsurprisingly, this is reflected in EOG's land position and its returns. Despite growing around 10% annually and a heavy investment in liquids growth, which is only recently starting to pay off, EOG averaged a 5.6% return on capital including all write downs from 2008-2012 and will deliver a 9.4% return on capital in 2013. In contrast, Chesapeake reported a -2.5% return during the 2008-2012 period and are forecasted to deliver just 3.7% in 2013 (5.7% lower than EOG's return). This is remarkable when considering the "success" Chesapeake has allegedly had in its JVs where it has secured almost $10 billion of carried drilling capital from partners over the last years, theoretically lowering its net outlay significantly.

The reason for the discrepancy in returns is the huge amount of capital Chesapeake spent on "moose pasture", the industry term for lands where development never moves forward. While EOG has just $1.2 billion of unproven acreage on its balance sheet (5% of total), Chesapeake has nearly $7.2 billion (20% of total) and this may be conservative depending on assumed amortization rates. This is a drag on returns. Not accounting for the lower net income driven by incremental amortization, Chesapeake's return on capital would be a point higher if it had an equivalent capitalized unproven asset base to EOG's. Taking into account the additional factor that without this capital base Chesapeake would not be amortizing the land position annually, it would potentially increase net Income by $700 million or raise returns even further to 6.7% in 2013, just 2.7% points behind EOG.

	EOG	CHK	Delta
2013 estimated EPS	8.15	1.67	na
Shares outstanding	272.97	648.18	na
2013 estimated NI $M	2224.706	1082.461	1142.245
2013 Average CE $M	26212.99	35375	-9162.01
Unproven capital (YE 12)	1253.864	7253.532	-5999.67
5 year average earnings $M	961	(939)	1899.632
5 year average interest $M	(141)	(107)	-34.212
5 year average CE $M	19,559	32,997	-13438.4
5 year ROACE %	5.6%	-2.5%	8.2%
2013 est ROACE %	9.4%	3.7%	5.7%
ROACE % if equivalent unproven	9.41%	6.71%	2.7%

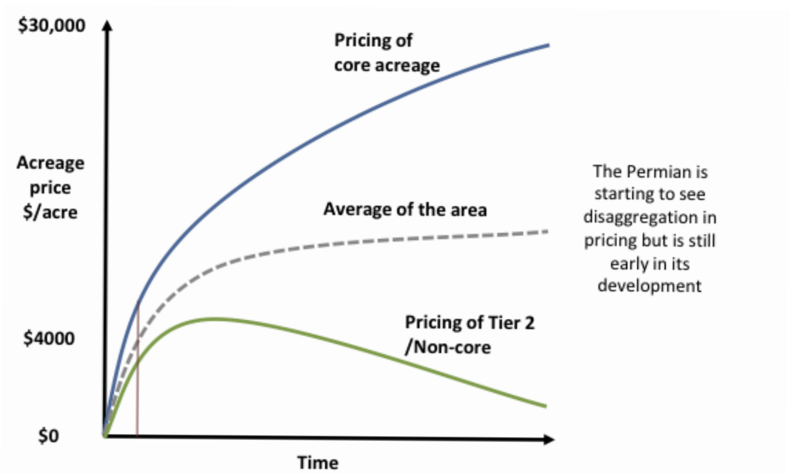
Exhibit 6: EOG versus Chesapeake comparison data

The Permian: The Pinnacle of Recycling

So where should investors be watchful in today's market for over-leasing? We believe the Permian is a critical focus for a number of reasons. First, land owners are experienced and tend to be aggressive on lease term (3+2 years is the norm), while prices ($3,000+/acre) are high. Second, capital intensity per acre is also high (up to $10 million of drilling and completion costs to hold a 160-acre block. As if this were not enough to contend with, the geology is complex, meaning the learning curve is lengthened versus other shale plays, and time to drill is relatively long due to the complex nature of the wells, making conservative leasing and timing very much of the essence.

The Permian Basin covers 52 counties and 86,000 square miles in West Texas and Southeast New Mexico and covers 16 million prospective acres, 3X the aerial extent of the Bakken (the size of Ireland). Assuming that 75% of this is either HBP or unattractive acreage, then there could be up to 4 million acres of new leases in the Permian that would need to be held. If each of these can be held by an $8 million well on a 160 acre basis, it translates into 25,000 well locations or $200 billion of capital spending over three years. This would be equal to two ExxonMobils ($410Bn enterprise value) spending 100% of their annual global upstream capex in the Permian Basin for three straight years and would require 1,400 rigs running continuously, essentially the entire US rig fleet.

The clear implication of this is that there are a large number of leases that will ultimately return to the market from distressed operators who do not have the capital to drill them. While many will likely try and farm them down as they reach the expiration point, many will delay this too long and will be left writing them off. Second, operators should be very conservative in the basin with respect to the acreage required versus other plays given the high capital costs of drilling and short duration. Lastly, there is likely to be a rapid high-grading and disaggregation of acreage with prices in Tier 2 acreage falling. This has been seen in other areas and is arguably already happening in the Permian where buyers are pricing down non-core acreage aggressively and bidding up the core. This is not to say some acreage will not be discarded for lack of information rather than weaker geology creating opportunities for those willing to do the extra work, but rather that most operators will be risk averse.



Exhbit 7: Schematic of expected acreage price evolution in the Permian

Implications for Kimmeridge

The question this data raises is what are the implications for Kimmeridge and how can we take advantage? The obvious initial answer is that by collating this data we can identify lease-distressed companies where we can potentially top lease (granting of a new oil or gas lease prior to the termination of an existing lease). Secondly, it highlights the value of duration on a lease and how paying for term is frequently worth it. Even in areas where you cannot get long lease term, it is critical to understand where you will sit in the expiration of leases in the area (ideally we want to have our leases expiring six months or more after everyone else). Lastly, the data allows us to build a framework for understanding the right amount of acreage in each project that is marketable but not un-drillable.

The data also dispels one myth, which is that the great land grab is over. Acreage comes around again and again. Leases are re-leased even in the core of a developing play and those who are willing to invest and to deal with smaller lease packages or difficult title can gain entry positions even in the core of well-established plays. Furthermore, given the scale of Kimmeridge's funds (around $100 million dedicated to leasing) based on the E&Ps expiring acreage alone ($24Bn), Kimmeridge has plenty of land to high-grade.

Notice & Disclaimer

- This document and all of the information contained in it, including without limitation all text, data, graphs, charts (collectively, the "Information") is the property of Kimmeridge Energy Management Company, LLC or its affiliates (collectively, "Kimmeridge"), or Kimmeridge's licensors, direct or indirect suppliers or any third party involved in making or compiling any information (collectively, with Kimmeridge, the "Information Providers") and is provided for informational purposes only. The information may not be reproduced or redisseminated in whole or in part without prior written permission from Kimmeridge.
- The Information has been derived from sources believed to be reliable but is not guaranteed as to accuracy and does not purport to be a complete analysis of any security, company or industry involved. The user of the information assumes the entire risk of any use it may make or permit to be made of the information. NONE OF THE INFORMATION PROVIDERS MAKES ANY EXPRESS OR IMPLIED WARRANTIES OR REPRESENTATIONS WITH RESPECT TO THE INFORMATION (OR THE RESULTS TO BE OBTAINED BY THE USE THEREOF), AND TO THE MAXIMUM EXTENT PERMITTED BY APPLIABLE LAW, EACH INFORMATION PROVIDER EXPRESSLY DISCLAIMS ALL IMPLIED WARRANTIES (INCLUDING, WITHOUT LIMITATION, ANY IMPLIED WARRANTIES OF ORIGINALITY, ACCURACY, TIMELINESS, NON-INFRINGEMENT, COMPLETENESS, MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE) WITH RESPECT TO ANY OF THE INFORMATION.
- Information containing any historical information, data or analysis should not be taken as an indication or guarantee of any future performance, analysis, forecast or prediction. Past performance does not guarantee future results. Opinions expressed are subject to change without notice.
- None of the Information constitutes an offer to sell (or a solicitation of any offer to buy), any security, financial product or other investment vehicle or any trading strategy.
- Kimmeridge Energy Management Company, LLC is a Registered Investment Adviser. Nothing herein is intended to constitute investment advice or a recommendation to make (or refrain from making) any kind of investment decision and may not be relied on as such.
- The Information has not been submitted to, nor received approval from, the United States Securities and Exchange Commission or any other regulatory body.

Contact Kimmeridge

New York
400 Madison Avenue,
Suite 14C, New York, NY 10017

London
Thornton House, Thornton Road
London, England SW19 4NG

Houston
952 Echo Lane, Suite 364
Houston, TX 77024

info@kimmeridgeenergy.com