EDISON

Diversified Gas & Oil

Initiation of coverage

Mature US onshore production consolidation

Oil & gas

Diversified Gas & Oil (DGO) has grown exponentially since listing on AIM in February 2017. The company's acquisition-led strategy has enabled it to amass over 6.5m net acres in the US Appalachian Basin, taking net production to 32.5kboed in FY18, underpinned by a 1P PDP 393mmboe net reserve base. We see potential for further inorganic growth, diligent management of existing well stock and infill drilling in the event of a gas price recovery to provide a platform for further growth. DGO trades below our base case valuation of 138.1p per share, which excludes asset consolidation and the infill drilling option value. A 2019 6.7% dividend yield supports the current share price and investment risk/reward is skewed to the upside given the potential for further value accretive M&A. Key sensitivities include gas price realisations and cash operating costs.

Year end	Revenue ($m)	EBITDA ($m)	PBT* ($m)	Net cash/ (debt) ($m)	Dividend yield** (%)	Capex ($m)
12/16	17.1	26.5	32.5	(37.1)	N/A	(9.2)
12/17	41.8	23.2	4.7	(55.8)	2.6	(93.1)
12/18e	215.2	113.8	70.5	(353.4)	4.8	(781.8)
12/19e	370.8	212.7	150.8	(240.5)	6.7	(16.3)

Note: *PBT normalised, excluding amortisation of acquired intangibles, exceptional items and share-based payments. **Dividend yield based on expected cash payment during year.

Assiduous management of overlooked assets

DGO's ability to extract residual returns from acquired mature production rests on the empowerment of production supervisors enabling them to extract maximum value, rather than volume, from their well stock. Unhindered by bureaucracy and layers of management, well tenders are able to optimise wells in real time. DGO's ability to maximise shareholder returns will be driven by its proficiency in managing lease operating expense (LOE) and the deferment of abandonment costs through extended well life as production declines.

Undervalued option on further M&A and infill

DGO's underlying asset base provides investors with a high-yielding dividend underpinned by long life, low decline predictable gas production. Rising gas prices driven by growth in US LNG and piped exports are an avenue to value growth. In addition, the market ascribes minimal value for further asset consolidation or exploitation of DGO's 6.5m net acre position through infill drilling.

Valuation: 138.1p excluding M&A and infill optionality

We provide a base valuation of DGO at 138.1p/share based on a long-term Henry Hub price of $3.10/mcf (2022). We see potential downside to 100.4p/share based on a 15% decrease in gas pricing and equivalent increase in costs. Risk/reward remains skewed to the upside with a valuation of 176.2p/share based on a 15% increase in gas price, and materially higher on inclusion of option value for further M&A and infill. It is not possible to quantify this option value without further data; however, we attempt to qualify prospective value in this note.

1 October 2018

Price	**121p**
Market cap	**£614m**
	US$/£0.73
Net debt ($m) at 30 June 2018	130
Shares in issue	507m
Free float	99%
Code	DGOC
Primary exchange	AIM
Secondary exchange	N/A

Share price performance

%	1m	3m	12m
Abs	13.8	28.7	63.6
Rel (local)	15.7	30.5	59.3
52-week high/low		128.5p	73.8p

Business description

Diversified Gas & Oil is a conventional natural gas and oil producer with a main focus in the US onshore. The company possesses long-life, low operational cost, mature producing assets with slow decline profiles in the Appalachian region, in the states of Pennsylvania, West Virginia and Ohio.

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Investment summary

Appalachian Basin late life asset consolidation

DGO was admitted to AIM in February 2017 and since then has made six asset acquisitions, investing over $861m in mature onshore production in the Appalachian Basin. Production is predominately natural gas (87% on an oil-equivalent basis for FY19), but the company has some oil price exposure through natural gas liquid (NGL) and condensate realisations. Group net production at the end of July 2018 on inclusion of EQT was c 60kboed from a 1P PDP reserve base of 393mmboe with a conventional well inventory of approximately 50,000 producing locations. The company's strategy focuses on the continued consolidation of both conventional and unconventional assets within its core areas of operation to drive down unit operating expense and expand margins. If gas prices rise materially from current levels, management retains the option of re-directing capital to organic growth – reducing well acre spacing and increasing recovery from DGO's vast 6.5m net acreage position.

Valuation: Risk/reward skewed to the upside

Our valuation is based on the NPV_{10} discounted value of the company's US onshore gas production adjusted for net debt and overheads. At 138.1p/share, our valuation does not include option value for either further NAV accretive M&A or infill drilling. Our analysis suggests that risk/reward is skewed to the upside at the current share price. A downside scenario, assuming low gas price realisations and higher costs, drives a valuation of 100.4p/share (17% below the current share price), while we see potential for M&A and infill drilling to lead to material upside beyond our producing asset NAV of 138.1p/share (upside of 14% to the current share price) and high case NAV of 176.2p/share (upside 46%). Our modelling of a single mature conventional well location suggests DGO's acquisition strategy has the potential to deliver strong returns if assets can be purchased at a discount to NPV_{10}, and unit LOE reduced and abandonment expense deferred. Amassing a deep well inventory is key in ensuring unit costs and production declines can be effectively managed while being material for the group. Consolidation of mature unconventional well locations in addition to conventional within the Appalachian Basin provides an opportunity to sustain continued inorganic growth.

Financials: Focus on growing shareholder returns

DGO has committed to returning c 40% of free cash flow (FCF) to shareholders, and we assume a dividend of 11.20c/share or a yield of 6.7% for FY19. The sustainability of this dividend will depend on DGO's ability to manage LOE and underlying decline rates in the short term and potential growth likely driver by further asset acquisitions. DGO has utilised a combination of equity and debt to fund acquisitions and, critically, has secured a low cost of debt capital at Libor + 2.25–3.25%, while maintaining leverage at 1.1x net debt/EBITDA for FY19. We expect gearing to fall as excess FCF (post-dividend) is used to reduce debt utilisation. Under the company's current borrowing base of $600m, management retains c $180m of headroom to fund acquisitions/organic investment.

Risk and sensitivities: Cost control

Key investment risks are logistical rather than sub-surface related, in our view. DGO needs to retain tight control of unit operating expenses, access to mid-stream infrastructure and abandonment timing/costs. Management retains the option to return assets to landowners when sufficiently depleted to limit abandonment exposure and recent acquisitions come with material mid-stream infrastructure reducing pipeline access risks.

Track record of value accretive acquisitions

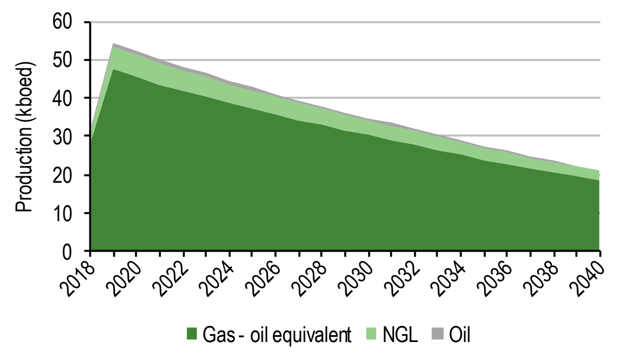
Acquire, produce, drill

DGO's strategy remains 'acquire, produce, drill'. This entails the acquisition of proven developed producing (PDP) reserves within the Appalachian Basin; maximisation of production and reserve recovery through the use of modern technology and operating practices; and the execution of low-risk, low-cost infill drilling if rates of return are deemed to be attractive in the prevailing commodity price environment.

Since its admission to AIM in February 2017, DGO has made six acquisitions: three in 2017, two in Q118 and one in Q218; corresponding to a total investment of $861m. This is in line with the company's strategy to leverage its position in the Appalachian Basin to capitalise on current market conditions and acquire mature producing assets in the region. Acquisitions have been funded through a combination of equity and debt, which comprises a five-year senior secured credit facility of up to $1bn from KeyBank and a syndicate of lenders. At completion of the EQT acquisition, we estimate that DGO has c $180m of debt available from a borrowing base of $600m to fund further acquisitions and ongoing capital requirements. Interest is benchmarked to Libor plus 2.25% to 3.25% depending upon utilisation. DGO's access to capital and the relatively low-cost of debt provides it with a competitive advantage over smaller market entrants looking to establish a similar acquire and build strategy.

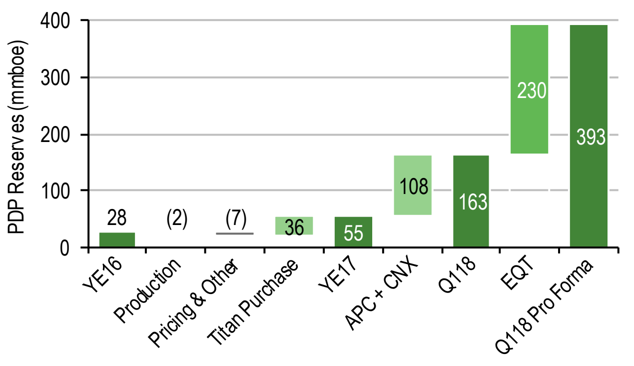
Through inorganic growth, net production has increased more than 1,900% from approximately 3kboed at the end of 2016 to c 60kboed at end-July 2018 and the number of producing wells reached approximately 50,000. DGO has managed to achieve operational synergies, reducing unit operating costs and extending the life of producing well stock.

Exhibit 1: Edison production forecasts



Source: Edison Investment Research

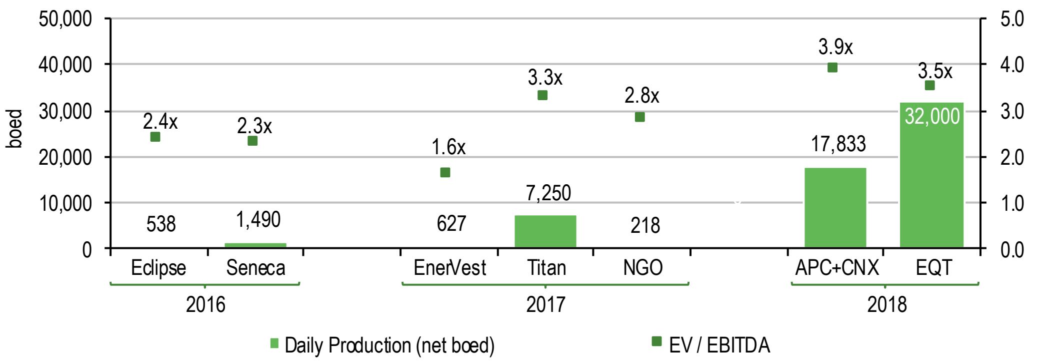
Exhibit 2: PDP reserve growth through acquisition



Source: DGO, Edison Investment Research

As shown in Exhibit 3, DGO's acquisitions have been executed at valuations ranging from 1.6x EBITDA to 3.9x, with the largest and most recent, EQT, at 3.5x EBITDA reflecting the higher margins being generated by liquid-rich well stock. Acquisitions have been accretive to EV-based multiple metrics with DGO trading at 6.5x EBITDA at the time of the EQT acquisition. We take a look at DGO's historical transactions relative to where the group is trading and company's US gas producer peer group in Exhibit 3 below.

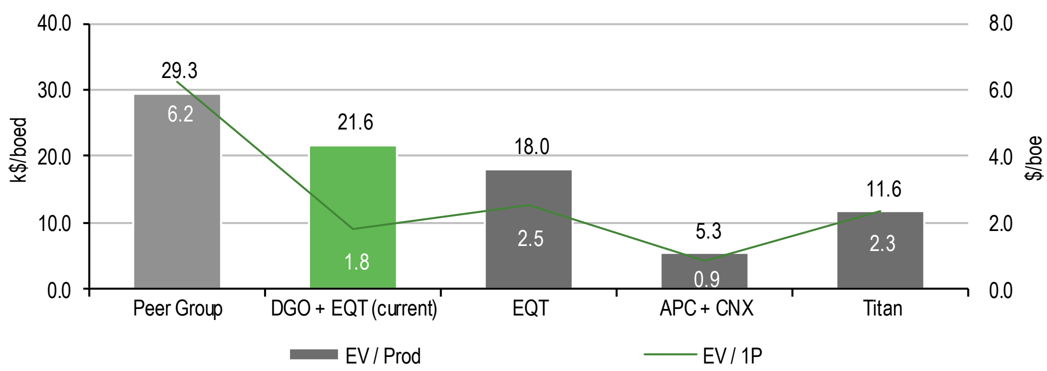
Exhibit 3: DGO historical transactions versus market valuations



Source: DGO, Edison Investment Research

Historical asset transactions have been conducted at a discount to DGO's US E&P peer group average (we include gas-biased US onshore operators) on production and reserve base multiple metrics such as EV/boed and EV/1P.

Exhibit 4: EV/Production and EV/1P indexes for the latest acquisitions



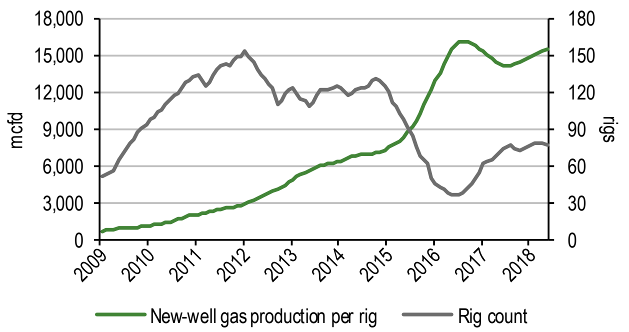
Source: Bloomberg, Edison Investment Research, Note: Peer group includes Antero Resources, Cabot Oil & Gas, Chesapeake, Devon Energy, EQT, Range Resources, Southwestern Energy and XTO.

Significant further consolidation running room

Despite DGO's progress in assimilating approximately 50,000 producing well locations, a significant opportunity exists to expand the company's mature conventional footprint to include mature unconventional production, much of which is situated adjacent to existing well inventory.

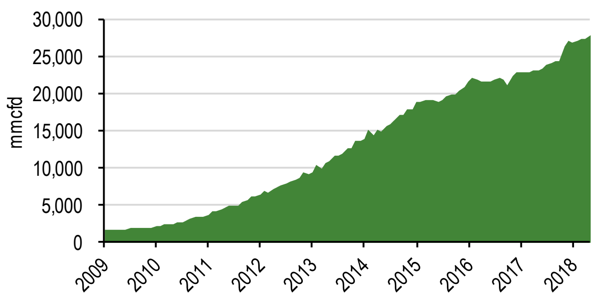
Unconventional well locations in the Appalachia region continue to increase and as horizontal well stock matures, we expect larger players in the region to high-grade their asset portfolios and reduce exposure to less productive well stock. Public data suggest there are over 11,000 unconventional wells drilled in Pennsylvania alone.

Exhibit 5: Appalachia region rig count and productivity



Source: EIA Drilling Productivity Report, Edison Investment Research

Exhibit 6: Appalachia region natural gas production



Source: EIA Drilling Productivity Report, Edison Investment Research

Larger operators have large portfolios of non-core assets

Prior to our site trip, we questioned why sellers would divest of large asset packages at a discount to their after-tax NPV_{10}. However, it became apparent how mature production required a different mindset and operational philosophy than that inherent within larger more bureaucratic organisations. Burdened with expensive fixed-cost structures designed to support unconventional drilling margins, low productivity wells rarely gain the attention of management in larger organisations and are prone to underinvestment and lack of attention, therefore becoming side-lined for divestment. For larger companies, the absolute return or NPV to be gained from operationally intensive management of mature production is deemed to be small relative to other opportunities competing for internal capital and resource. Divestment provides an opportunity to release capital and associated provisions with the opportunity to re-direct funds. This, in turn, creates an opportunity for smaller companies such as DGO that can dedicate human resource and capital to maximising recovery and extracting residual value from mature well stock.

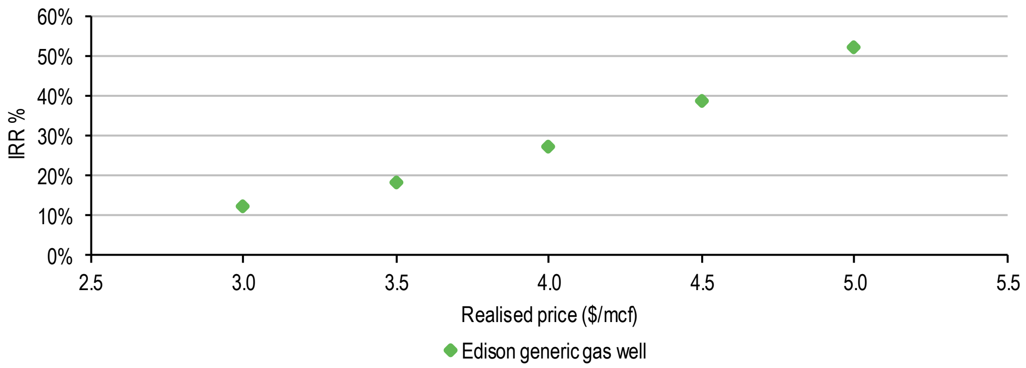
Holding Marcellus shale through conventional production

The prevailing market conditions in the Appalachian Basin have created a compelling buyer's market for well-capitalised operators wishing to expand their portfolio of mature, producing assets. The rapid expansion of unconventional activity on the Utica and Marcellus shale assets, the rights to which are 'held by production', means the mature, often conventional producing assets which routinely retain the rights to the unconventional assets held in deeper zones within the same leasehold have become non-core to larger industry players. As such, these parties are keen to monetise these wells that have reached their terminal decline rates, often already having paid back a multiple of their initial investment, allowing them to reinvest that cash flow into their active development programs. Enhancing the value from their perspective is the current offloading the related future abandonment liabilities to buyers who can maintain the conventional well production, which for wells in this region of the United States can be for 50+ years, while retaining the rights to the unconventional reservoirs they expect to develop at some point in the future. We believe this dynamic has enabled DGO to carve out a niche. Greater access to equity and debt capital than smaller landowners and appetite to extract residual returns from mature well stock has enabled DGO to amass a vast land position encompassing 6.5m net acres and approximately 50,000 producing well locations.

Extracting residual returns from acquired assets: A generic example

In the generic example below, we look at per-well returns that could be generated from the drilling of new conventional wells, essentially infill drilling across DGO's acreage, then compare these to returns that could potentially be generated through asset acquisition. We expect management to focus on asset consolidation for the foreseeable future given the superior returns in the current commodity price environment. As it stands, we do not believe DGO is structured to carry out large-scale drilling operations, a strategy that would require the creation of an in-house drilling department to manage logistics, operations and sub-contractors. We could see DGO focusing on selected liquid-rich drilling opportunities present within the acquired EQT asset base – these provide superior returns to dry gas in the current commodity price environment.

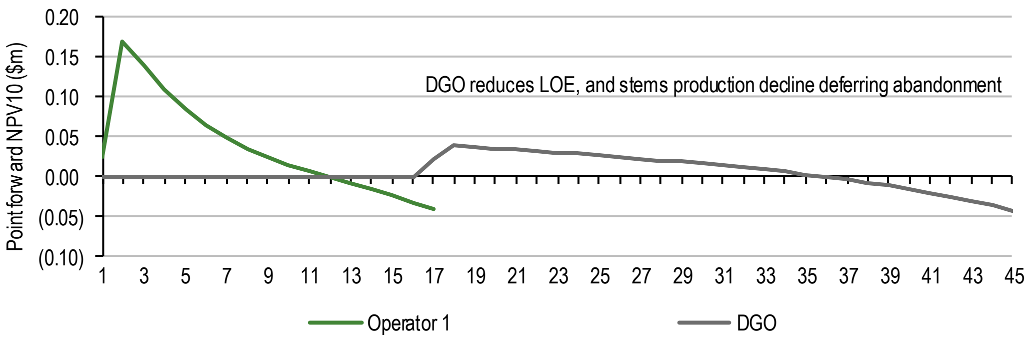
Exhibit 7: Edison analysis of IRRs from new conventional wells



Source: Edison Investment Research. Note: *Edison assumes well cost of $200k and LOE including gathering and transport of $4.5/boe, type curve as Exhibit 35.

DGO's business model and strategy is based around the acquisition of non-core assets within the Appalachian Basin. Our analysis below shows the point-forward NPV_{10} for a single conventional gas well location. We assume that 'Operator 1' drills the well, which it then looks to divest once the wells have rolled off peak production and their hyperbolic declines to arrive at a terminal decline rate whereby the wells no longer contribute meaningfully to their consolidated production. Instead, they can monetise the wells and transfer the future abandonment cost to operators who will extend the life of the wells through a variety of initiatives that reduce operating expenses while maintain production on shallow decline. For our generic gas well, the return that can be generated by DGO through this strategy is 15% to 45% largely dependent on acquisition cost. Returns generated by DGO will also be sensitive to gas price realisations, LOE and abandonment cost and timing.

Exhibit 8: Extracting residual value – point-forward NPV for generic gas well



Source: Edison Investment Research

Assiduous management of overlooked assets

In Q218, we conducted a site visit to DGO's asset base in Pennsylvania; this provided us with a valuable insight into the company's assets, operational practices and consolidation potential. DGO's assets stretch across the gas-rich Appalachian region and include mature conventional production as well as unconventional Marcellus gas production.

We believe that DGO's approach and corporate structure put it in a unique position to continue to consolidate US onshore conventional and unconventional assets and maximise resource recovery from assimilated well stock. Competition for assets in the company's core areas is limited as larger operators continue to divest mature well stock and smaller players lack scale as well as the access to capital to compete.

Bespoke solutions for overlooked assets

While the oil and gas majors continue to pursue the simplification and standardisation of operational and field development practices, we believe DGO takes a contrasting approach, devoting resource to scrutinise and maximise the value of each operated well location. This bespoke approach has enabled DGO to increase average production rates from mature wells and reduce unit costs, driving a significant improvement in unit netback.

DGO employs approximately one well tender per 100 wells. As the company increases well density through future acquisitions, it expects the well-to-well tender ratio to increase by securing more wells in existing locations. This cost-saving improvement is realised primarily by route optimisation, which reduces driving time between wells and will reduce overall operating expense. Well tenders and production foremen have significant responsibility and autonomy, with accountability for well pad economics and the authority to deploy small capital improvements that generate quick payback.

Extracting residual returns: Synergies and low-hanging fruit

Management has highlighted several initiatives that have successful reduced unit LOE for assimilated assets, these include:

- Reinstating production from shut-in wells.
- Evaluation and execution of workover programmes.
- Reduced third-party contractor expense. Replacing contractors with employees with a longer-term vested interest in well performance.

- Elimination and downsizing of compression and replacement of inefficient compression infrastructure.
- Renegotiation of transportation contracts.
- Optimisation of the transport network.
- Flattened organisation structure.
- Sharing of operational best practices across the group.

Acquired assets are often non-core to the seller and opportunities to optimise and workover have often been overlooked. While the NPV to be generated from such activities is small, IRR is higher and payback quick. Scale is key in ensuring absolute value is material for DGO and its shareholders.

Extracting residual returns: In the field

Below are a couple of examples of how DGO extracts residual returns from mature well stock, through redeploying existing equipment and bespoke management of individual wells to ensure production rates are maximised. Top-tier producing wells across DGO's producing 50,000 well stock attract the most oversight from well tenders, with production supervisors incentivised to focus on returns on maintenance capex rather than just incremental volumes. In the field, we saw a couple of examples of DGO's approach to asset management in practice. A challenge for DGO will be ensuring unit LOE can be maintained despite declining production. Several approaches are likely to help in this regard including the use of SCADA instrumentation to enable remote well oversight and possibly also remediation.

Optimising the use of Venturi plungers to reduce casing pressure

Venturi plungers are used across a large number of DGO's mature conventional well stock to reduce casing pressure by removing water from the bottom of the wells' production tubing. The timing at which Venturi plunger runs are initiated has a direct impact on average daily flow rates. To optimise well maintenance, DGO employs numerous well tenders to regularly attend to and adjust systems such as this to maximise flow rates. Production supervisors manage the deployment of well tenders to well locations to maximise the return on well maintenance/modification expenses.

Export gas compression

At a well location we visited, a spare gas compressor unit that was unused was deployed to a well location to reduce wellhead pressure and increase gas flow rates. The installation cost of the small compression unit was minimal and payback was achieved in a matter of days after including compressor-running costs. The NPV impact of minor modifications such as these is assessed and managed at the field level.

Exhibit 9: Optimised deployment of Venturi plungers

Source: Edison Investment Research

Exhibit 10: Export gas compression

Source: Edison Investment Research

DGO expects to apply a similar operating philosophy across the group. However, we expect best group-wide best practices to evolve as the company assimilates recent acquisitions.

Valuation

We value DGO using a conventional NAV approach based on the NPV_{10} of the company's producing assets minus overheads and net financial liabilities. A full breakdown of our NAV is provided in Exhibit 13.

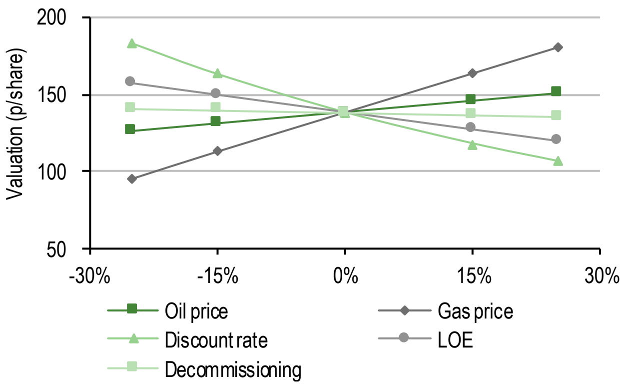
Asset-level valuations are carried out based on state-specific fiscal terms, basis differentials and costs. We also include an abandonment schedule of 100 wells per year until 2035, and 1,000 wells per year beyond 2035 across the portfolio, and abandonment costs of $24,000 per well in line with estimates provided in the company's H118 results, EQT acquisition prospectus and US onshore industry averages.

As mentioned earlier in this note, we do not include an incremental value for M&A potential or infill drilling. However, it is important to recognise that management has created material value for shareholders through asset acquisition at attractive valuations. While the Appalachian Basin has a finite level of conventional asset opportunities, we see a growing opportunity in the unconventional sector, where larger players are looking to recycle cash from mature unconventional producers into high-return drilling opportunities. Also not included in our valuation is the infill drilling opportunity present on existing leases, if DGO elects to reduce average well acre spacing and maximise resource coverage from its existing land position.

Risk/reward skewed to the upside: Embedded optionality

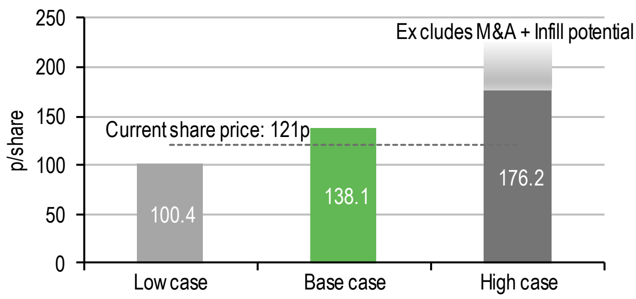
We value DGO's existing assets with a relatively high level of confidence, based on booked reserves and known fiscal terms. Key areas of uncertainty are realised commodity prices, applied discount rate and costs as shown in Exhibit 11. The value on M&A upside potential or risked infill drilling NPV is far less certain but is likely to be more than zero. While one could attempt to subscribe an element of option value to both M&A and infill drilling, we have decided against this approach. Instead, we have stress-tested our base case valuation to the downside and the upside to formulate high and low value scenarios (see Exhibit 12). We see a 46% upside from the current share price in the event of higher gas prices and lower LOE and abandonment costs. Disproportionally, we see just 17% downside from the current share price in the event of lower gas prices, higher unit and decommissioning costs. We conclude that the risk/reward of investment for shareholders is skewed to the upside, and materially skewed to the upside if one were to include M&A and infill option value.

Exhibit 11: Valuation sensitivity



Source: Edison Investment Research

Exhibit 12: Risk/reward skewed to the upside



Source: Edison Investment Research. Note: Low case: 15% higher LOE/abandonment costs and 15% lower gas price; High case: 15% lower LOE/abandonment cost and 15% higher gas price.

Infill upside being assessed

DGO has acquired a vast 6.5m net acre position, paying minimal value beyond PDP cash flows. While it is difficult to quantify the value of the company's infill drilling opportunity, we expect management to assess the potential of its acquired leasehold once it has had the opportunity to work up quick payback optimisation opportunities such as workovers. High liquid yield drilling opportunities present with the acquired EQT asset portfolio (e.g. Lower Huron inventory) may provide a good starting point. Beyond this, DGO expects to establish type curves using modern drilling and completion techniques, reassess drilling costs and work up a drilling programme that offers a competitive return on capital relative to less capital-intensive opportunities.

Valuation of mid-stream assets

We include a discounted value for payments DGO receives for third-party use of services and mid-stream assets in our valuation – currently estimated at c $12m pa or $118m in our NAV. We note that DGO has over 6,400 miles of pipeline and 59 compressor stations, which have spin-out optionality and the potential to secure DGO a competitive advantage when assessing future deals in the region.

Valuation breakdown by asset

The NAV table below provides a breakdown of our valuation by asset, using data available in the company's last published prospectus and CPR as well as state public sources.

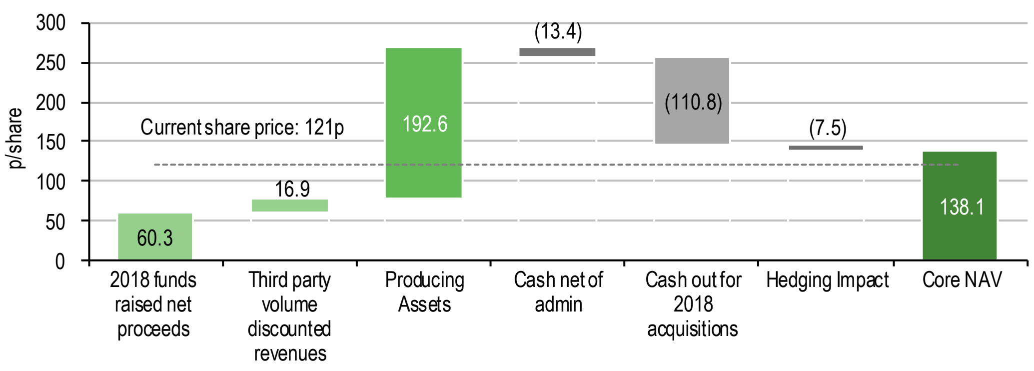
Exhibit 13: Edison detailed NAV breakdown for DGO

Asset	Country	Diluted WI	CoS	Recoverable reserves Net post royalty	NPV/boe	Net risked value	Risked value
		%	%	mmboe	$/boe	US$m	p/share
Net (debt)/cash end 2017						(55.8)	(8.0)
SG&A - NPV of 3yrs						(37.8)	(5.4)
2018 funds raised net proceeds						420.0	60.3
Cash out for 2018 acquisitions						(772.0)	(110.8)
Hedging impact						(52.1)	(7.5)
Third-party volume discounted revenues						118.0	16.9
Production							
Kentucky	US	90%	100%	164	6.0	770.1	110.5
Ohio	US	82%	100%	16	5.4	87.2	12.5
Pennsylvania	US	82%	100%	109	2.2	237.2	34.0
Tennessee	US	82%	100%	5	1.8	8.7	1.3
Virginia	US	81%	100%	9	5.6	31.2	4.5
West Virginia	US	83%	100%	95	7.3	207.9	29.8
Core NAV				**398**		**962.5**	**138.1**

Source: Edison Investment Research. Note: Number of shares: 507m, FX: US$/£0.73 (due to the recent volatility in exchange rates and for the sake of consistency, we assume the FX based on the average of the last six months before the end of each quarter).

Exhibit 14 breaks down our valuation by asset class showing where our base case core NAV is relative to the current share price.

Exhibit 14: NAV waterfall



Source: Edison Investment Research

Key sensitivities: Gas price and LOE

Key drivers of DGO's valuation are assumed gas price and LOE. The table below provides a base case valuation sensitivity to these key drivers. Our base assumes a long-term (2022) gas price of $3.10/mcf and LOE of $4.52/boe both inflated by 2.5% thereafter.

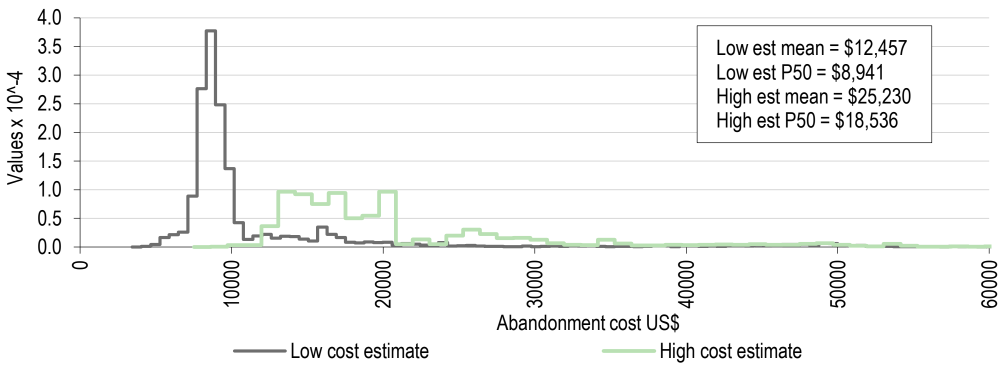
Exhibit 15: Valuation sensitivity to LOE and gas price assumption

LOE $/boe	-25%	-15%	4.52	+15%	+25%
HH $/mcf LT					
-25%	114.6	107.1	95.9	84.7	77.2
-15%	132.0	124.5	113.3	102.0	94.6
3.10	156.8	149.3	138.1	126.9	119.4
+15%	182.1	174.6	163.4	152.2	144.7
+25%	198.8	191.3	180.1	168.9	161.4

Source: Edison Investment Research

Some in the market have also questioned DGO's net abandonment liabilities, given the company's depth of mature well stock. We assume an abandonment schedule of 100 wells per year until 2035, and 1,000 wells per year beyond 2035 across the portfolio, and an abandonment cost of $24,000 per well in line with estimates provided in the company's H118 results, EQT acquisition prospectus and US onshore industry averages. Potentially offsetting the impact of these costs is the lower number of wells per year required to satisfy the regulators in the state in which DGO operates. We have also stress-tested our valuation for changes in per-well abandonment cost and compared cost relative to historic actual costs to increase our comfort in our valuation approach. We do not see decommissioning costs and the pace at which decommissioning occurs (we assume 100 wells per year until 2035, and 1,000 wells per year beyond 2035) as a key driver, unless costs or timing vary materially from our base case assumptions. We have also analysed publicly available data on abandonment cost estimates for over 8,100 wells in Pennsylvania. These data are below and show a low P50 cost estimate per well of $8,941 and high P50 cost estimate of $18,536, which is materially below our assumed abandonment costs but in line with DGO CPR assumptions.

Exhibit 16: Pennsylvania state decommissioning cost estimates for >8,100 wells*

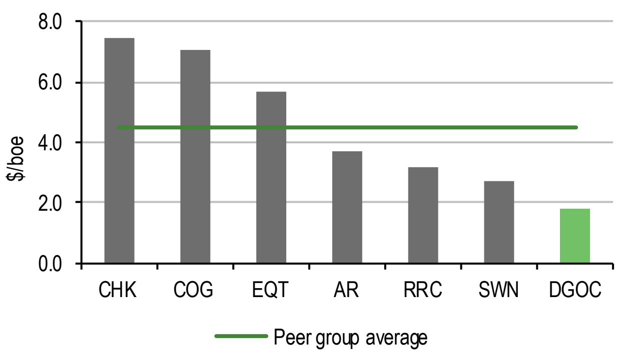


Source: Edison Investment Research, Pennsylvania State Department of Environmental Protection. Note: *Data include low and high estimates for over 8,100 wells based on historical actual costs.

Comparative valuation

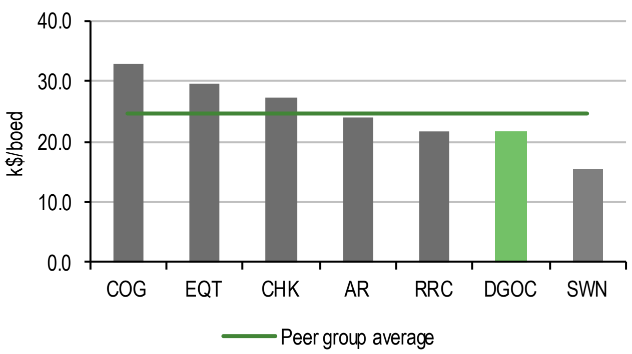
In this section, we compare DGO to a number of its US onshore gas biased peers, looking at where the company trades on comparative multiples including EV/1P, EV/kboed, P/CF FY2018e and 2019e, and RLI. DGO trades at a discount to the majority of its gas biased peers on reserve and production metrics, but at a premium on short-term cash flow metrics. FY18 cash flows only include a part year contribution from EQT – at 3.5x FY19 cash flow DGO is more in line with the peer group average on this metric. We note that DGO is a London listed mid-cap whereas the peer-group is made up of US listed E&Ps, which are typically valued on a combination of prospective P/CF metrics and NAV by US analysts. Our DGO prospective cash flow per share forecasts do not include any incremental upside from further M&A, which is a key component of the company's growth strategy.

Exhibit 17: EV/1P reserves



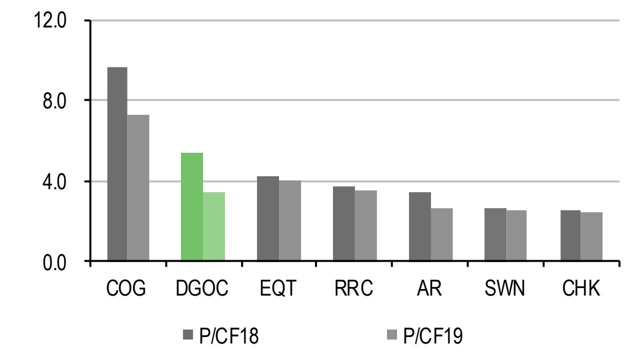
Source: Bloomberg, Edison Investment Research

Exhibit 18: EV/boed (FY18)



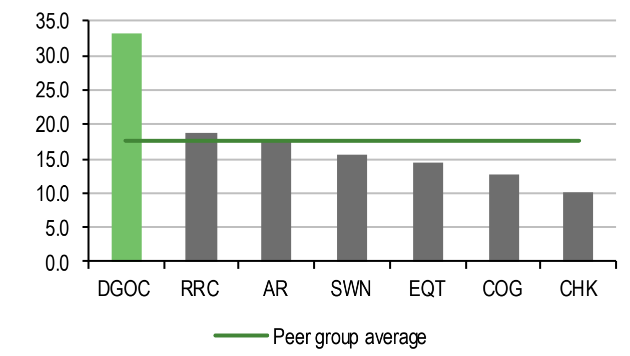
Source: Bloomberg, Edison Investment Research

Exhibit 19: P/CF (FY18 and FY19)*



Source: Bloomberg, Edison Investment Research. Note: *DGOC reflects Edison forecasts.

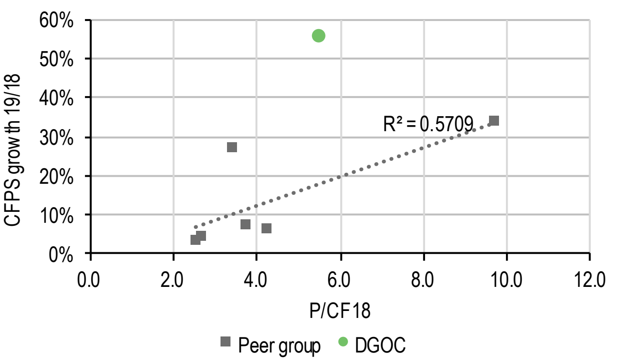
Exhibit 20: 1P Reserve Life Index (RLI in years)



Source: Bloomberg, Edison Investment Research

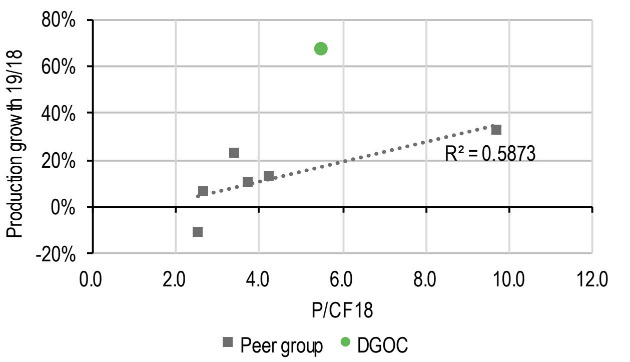
The exhibits below look at correlations between valuation and growth and yield metrics. We see some reasonable correlations despite the lack of data points in the peer group. DGO trades at a small premium to the group based on forecast cash flow growth and production growth as shown relative to the trendlines below.

Exhibit 21: CFPS growth FY19/FY18 vs P/CF FY18



Source: Bloomberg, Edison Investment Research. Note: *Trendline excludes DGOC.

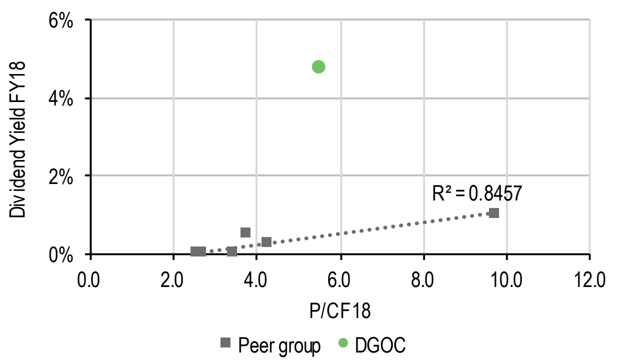
Exhibit 22: Production growth FY19/FY18 vs P/CF FY18



Source: Bloomberg, Edison Investment Research. Note: *Trendline excludes DGOC.

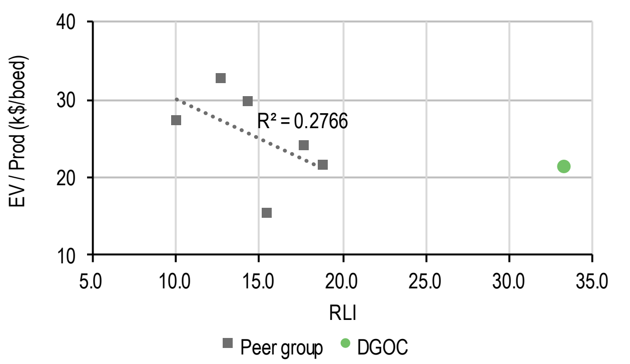
DGO pays a substantially higher dividend than the peer group average with all peers yielding less than 1%, relative to DGO's 4.8% in FY18. DGO also has a significantly higher reserve life index (FY18 production relative to last reported 1P reserves), with the market placing greater value on current production rather than depth of reserve base.

Exhibit 23: Dividend yield FY18 vs P/CF FY18*



Source: Bloomberg, Edison Investment Research.

Exhibit 24: EV/Production FY18 vs RLI



Source: Bloomberg, Edison Investment Research.

Note: *Trendline excludes DGOC.	Note: *Trendline excludes DGOC.

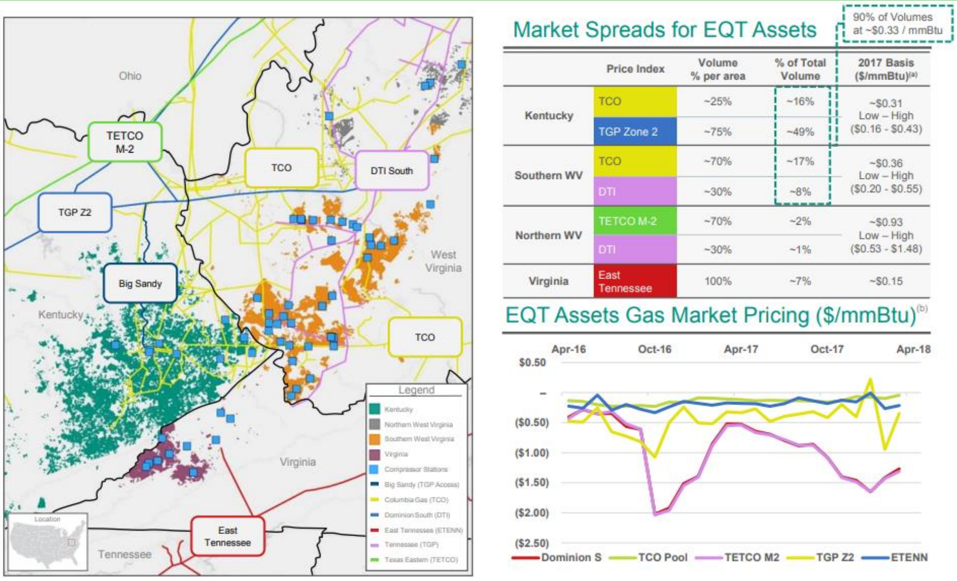
Appalachian region commodity benchmarks

Gas pricing and differentials

Over the past decade, natural gas production in the Appalachian region has grown faster than pipeline capacity, driving up the regional differential relative to Henry Hub. More recently, an increased capacity to deliver gas to regional markets has narrowed the price spread, but a seasonal pattern in price differential remains, with Dominion South pricing showing a widening price spread in the summer months. As infrastructure in the region is built out, differentials are narrowing and price seasonality is reducing, benefiting Appalachian producers.

Growing Marcellus gas production has driven activity in the midstream sector with numerous gas pipelines under construction taking gas molecules to meet demand from LNG exporters on the southern coast (the EIA expects LNG exports to increase from 1.9Bcf/d in 2017 to 3.0Bcf/d in 2018 and ramp up to 5.5Bcf/d by the end of 2019) as well as natural gas exports to Mexico (pipeline capacity to Mexico has tripled since 2010). Pipeline capacity constraints and transport tariffs drive the differential between the Appalachian region gas hub pricing and Henry Hub, which stands at a DGO volume-weighted average c $0.4–0.5/mcf.

Exhibit 25: Gas market spreads for acquired EQT assets

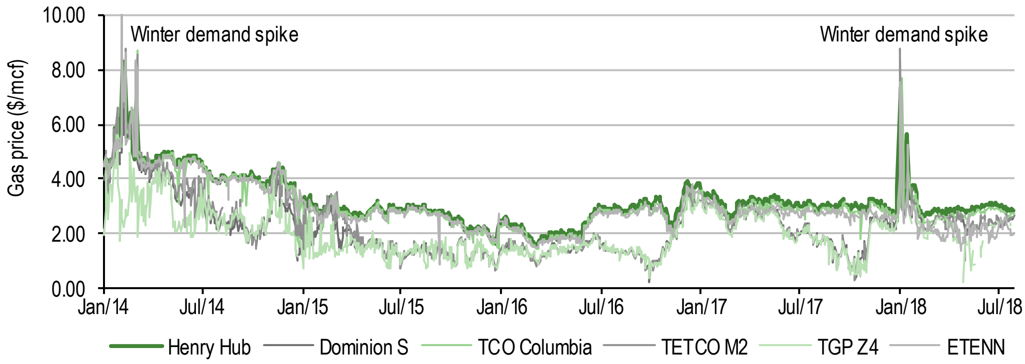


Source: DGO

The differential between Dominion South in southwestern Pennsylvania and Henry Hub fell materially in 2017 as the Equitrans expansion of the Ohio Valley Connector and the Rockies Express Pipeline capacity enhancement project provided incremental capacity. In June 2018, the Rover's interconnector near Detroit was completed, increasing takeaway capacity from southwest Pennsylvania and further narrowing the Dominion South price spread. The Transco Atlantic Sunrise project, expected to be completed by the end of 2018, will connect natural gas production centers in northeastern Pennsylvania and is expected to narrow price spreads between the northern hubs and Henry Hub.

A further 20 pipeline projects are planned, and as such we expect the DGO realised gas differential to remain close to current levels at c $0.5/mcf. Under existing debt arrangements, DGO hedges this differential with swap arrangements.

Exhibit 26: Spot prices in Appalachian region gas hubs



Source: Bloomberg, Edison Investment Research

The table below highlights several major projects pending construction, filed with the Federal Energy Regulatory Commission (FERC) that will add further pipeline capacity in the Appalachian region – the projects in the table below make up a total of over 2,400mmcfd of incremental pipeline capacity.

Exhibit 27: FERC applications for Appalachian region pipeline projects

Year filed	States	Capacity (mmcfd)	Project
2017	NJ	60	Texas Eastern Transmission, LP, Lambertville East Expansion Project
2017	NJ	65	Transcontinental Gas Pipe Line Company, Gateway Expansion Project
2017	PA, OH	55	RH energytrans, LLC, Risberg Line Project
2017	NJ	190	Transcontinental Gas Pipe Line Company, Rivervale South to Market Project
2017	NJ, NY, PA	400	Transcontinental Gas Pipe Line Company, Northeast Supply Enhancement Project
2017	PA, WV	47.5	Columbia Gas Transmission, LLC, Eastern Panhandle Expansion Project
2018	VA, SC, GA, LA	296	Transcontinental Gas Pipe Line Company, Southeastern Trail Project
2018	OH, WV	275	Columbia Gas Transmission, LLC, Buckeye XPress Project
2018	PA	133	National Fuel Gas Supply Corporation, Line N to Monaca Project
2018	PA, DE	775	Adelphia Gateway, LLC, Adelphia Gateway Pipeline
2018	PA, OH	120	Dominion Energy Transmission, Inc., Sweden Valley Project
Total capacity		**2,416.5**	

Source: FERC

Edison's oil and gas base case price assumptions are provided in the table below and include our assumed realised gas price differential relative to Henry Hub. In our base case, we assume WTI in line with EIA forecasts for 2018 and 2019 at $67.03/bbl and $67.36/bbl respectively, rising to $70.00/bbl long-term (2022). For Henry Hub we assume a gas price of $3.10/mcf in 2018, $3.23/mcf in 2019 and $3.10/mcf long-term (2022).

Exhibit 28: Edison's valuation pricing assumptions

Commodity benchmarks	2018	2019	2020	2021	2022
WTI ($/bbl)	67.03	67.36	67.84	68.91	70.00
Henry Hub ($/mcf)	3.10	3.23	3.13	3.12	3.10
NGL* ($/bbl)	11.00	11.00	11.00	11.00	11.00
Premium/(discount) to benchmark			**Oil ($/bbl)**	**Gas ($/mcf)**	**NGL ($/bbl)**
DGO Legacy Assets*			(2.43)	(0.50)	0.00
EQT – Kentucky*			(9.23)	(0.26)	45% of WTI
EQT – N West Virginia*			(4.04)	(0.45)	0.00
EQT – S West Virginia*			(6.83)	(0.32)	0.00
EQT – Virginia*			(4.68)	0.46	0.00

Source: Edison Investment Research. Note: *As per EQT Acquisition CPR (June 2018).

NGL benchmarks and pricing

The acquisition of assets from EQT in June 2018 significantly increases DGO's exposure to WTI, with produced NGLs highly correlated to movements in WTI. Pro forma reserves composition post-EQT is 89% natural gas, 8% NGL and 3% oil. NGLs are typically sold at Mont Belvieu (Gulf Coast pricing) or a 45% discount to WTI. We assume this discount remains static in our commodity price forecasts.

Management

Robert Marshall Post: non-executive chairman: Mr Post joined DGO in 2005 as 50% owner with Mr Hutson Jr and has served as the non-executive chairman since August 2017. Before joining DGO, Mr Post owned and operated an overhead crane company for 20 years.

Robert 'Rusty' Russell Hutson, Jr: chief executive officer: Founder and CEO, Rusty Hutson Jr was born and raised in West Virginia, and is the fourth generation in his family to immerse himself in the oil and gas industry. He graduated from Fairmont State College (WV) with a degree in accounting and earned his CPA License (Ohio). Prior to founding Diversified Gas & Oil in 2001, Rusty spent 13 years steadily progressing into multiple leadership roles at well-known banking institutions such as Bank One and Compass Bank. His final years in the banking industry were spent as CFO of Compass Financial Services.

Bradley Grafton Gray: finance director and chief operating officer: Prior to joining the company in October 2016, Mr Gray held the position of senior vice president and CFO for Royal Cup, a US-based commercial coffee roaster and wholesale distributor of tea and other beverage related products. Prior to Royal Cup, from 2006 to 2014 Mr Gray worked in the petroleum distribution industry for the McPherson Companies and held the position of executive vice president and CFO.

Eric Williams: chief financial officer: Mr Williams joined DGO in July 2017 from Callon Petroleum. During Eric's more than seven-year tenure with Callon, the company grew significantly from a market capitalisation of US$40m to over US $3.5bn, successfully transforming itself from a deep-water asset focused company to an onshore, pure-play horizontal drilling operator in the Permian Basin. Mr Williams began his career in PwC's Birmingham, Alabama audit practice and prior to his time at Callon served in various roles including internal audit with a focus on Sarbanes Oxley implementation and compliance, controllership and financial reporting for several US publicly traded companies.

Mitigating risks associated with company strategy

The operation of mature well stock has associated operational rather than subsurface uncertainties and risks, which DGO looks to constrain and minimise. We discuss several of these company-specific operational risks and mitigation strategies below. The two key sensitivities are gas prices and LOEs:

- **Natural gas and crude oil pricing:** changes in commodity pricing may affect the value of DGO's natural gas and oil reserves, operating cash flow and adjusted EBITDA regardless of operating performance. DGO's management can mitigate several of these risks and streamline cash flows with adequate derivatives in place.
- **Managing LOE as well stock matures:** management sees potential to reduce LOE from the current $4.52/boe as the company consolidates incremental production adjacent to its core areas of operation reducing unit costs. Low decline rates and relatively low maintenance capex requirements ensure that unit LOE can be sustained. Longer term, management expects to high-grade the company's portfolio to reduce exposure to marginal, higher unit LOE assets.
- **Infrastructure access**: DGO is reliant on mid-stream access to export and sell natural gas. At a macro level, there is spare gas pipeline capacity across the Appalachian Basin and further capacity is under construction enabling gas to feed existing and planned LNG export capacity on the south coast. Exhibit 27 shows FERC applications for further pipeline expansion in the Appalachian region – continued competition for molecules in the mid-stream should act to limit the differential at which DGO sells its gas relative to Henry Hub.

- **Water disposal:** most of DGO's wells produce with a high gas water ratio (GWR) – produced water is disposed to meet EPA regulations. DGO pays third parties a volume-based fee for the disposal of water. The company is seeing a reduction in water disposal tariffs as it increases in scale, and competition within the sector is likely to remain robust given the limited barriers to entry. While water disposal is likely to remain a meaningful proportion of variable costs, we do not see the risk of significant cost inflation. CNX last reported water disposal costs in Pennsylvania of $8.12/bbl, West Virginia of $5.89/bbl and Ohio $7.11/bbl.
- **Abandonment liabilities:** DGO provides for abandonment liability. All of the company's wells are onshore and easily accessible, enabling plugging and abandoning (P&A). In the H118 results, DGO presented a detailed analysis on plugging and abandonment costs based on their recent operational experiences, and the company expects that over 87% of well portfolio will cost less than $25,000 per well. These costs appear to be broadly in line with industry benchmarks, which vary from $5 to $15 per well foot. DGO's production largely consists of long-life, low-decline mature assets with production expected to extend out to 2050 and beyond, which significantly reduces liability on a present value basis. DGO expects to extend economic well lives beyond current expectations potentially offsetting the non-cash accretion associated with the unwinding of the booked decommissioning liability.
- **Ensuring safe and compliant operations:** DGO promotes a culture of environmental awareness and safety amongst its employees and contractors. The company's assets are onshore, and largely mature wells with relatively low wellhead pressures. While their inherent safety and environmental risk in the oil and gas sector, we believe the likelihood of a high impact event to be lower than a number of the company's peers that operate high pressure, sour gas or offshore assets.
- **Success of acquisition strategy:** returns will ultimately be reliant upon the quality and performance of the assets being acquired directly or indirectly by DGO. The success of the company's strategy also depends on management's ability to identify potential assets, acquire them on favourable terms and generate value from them.

Financials

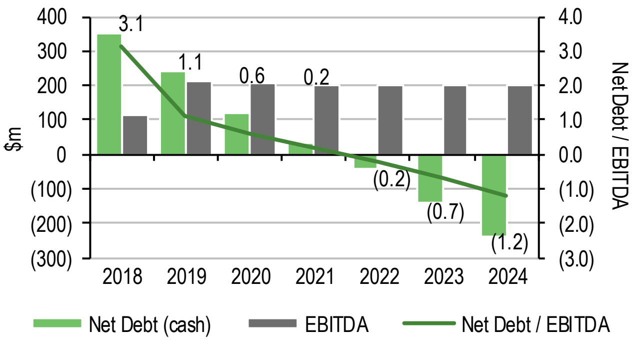
DGO is a profitable producer and low-cost operator generating FCF for distribution to shareholders and meeting debt obligations.

Free cash generation and dividends

DGO's dividend policy is to return c 40% of FCF to shareholders, and management expects to sustain quarterly dividends close to the current 2.8c/share. Key drivers of FCF and dividends will be gas realisations and LOE, as under the company's current mode of operation maintenance and drilling capex spend is minimal. Short-term FCF has the potential to fall if DGO enters an extensive drilling phase.

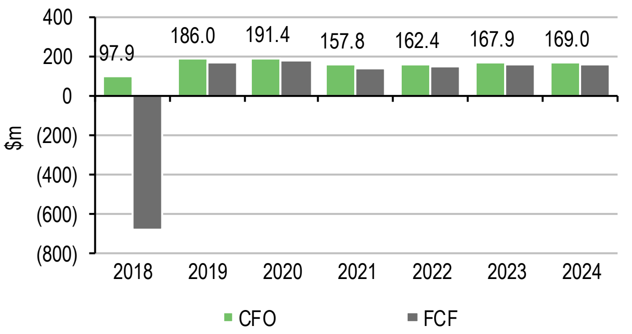
Below we provide our FCF forecasts based on our underlying commodity price assumptions. We forecast a dividend of 11.2c/share in 2019, equating to a yield of 6.7% at the current share price. We also assume FCF is used to reduce net debt and gearing with net debt/EBITDA falling from a forecast 3.1x in FY18 to just 1.1x in FY19e and 0.6x by FY20e in the absence of further acquisitions. In reality, DGO's balance sheet is likely to evolve to incorporate further consolidation within its core areas of operation. DGO benefits from attractive financing terms with its corporate facility priced at Libor plus 2.25–3.25% depending on utilisation.

Exhibit 29: Net debt and net debt/EBITDA



Source: Edison Investment Research

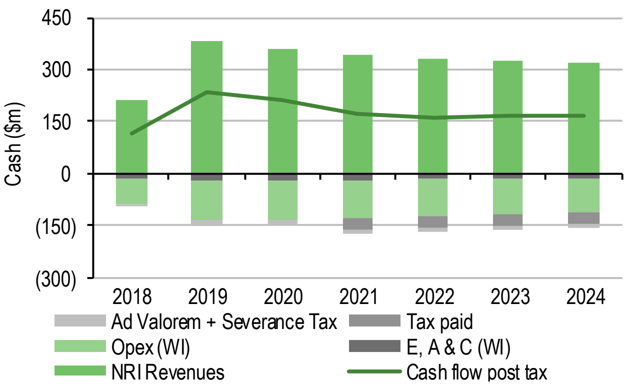
Exhibit 30: CFO and FCF generation



Source: Edison Investment Research

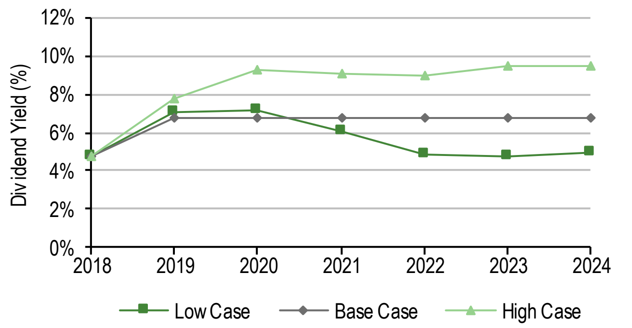
Exhibit 32 below shows the impact of our lower gas price and higher-cost valuation scenario on dividend yield – under this scenario dividends would be maintained close to our base case 6.7% for FY19. In our base case we assume management sustains the quarterly payout at 2.8c/share, and in high and low cases, pays out 40% of FCF including short-term tax benefits (we recognise that management may elect to exclude short-term tax shields from the calculation of FCF for the purposes of the dividend).

Exhibit 31: Cash generation (unleveraged)



Source: Edison Investment Research

Exhibit 32: Dividend yield forecast*

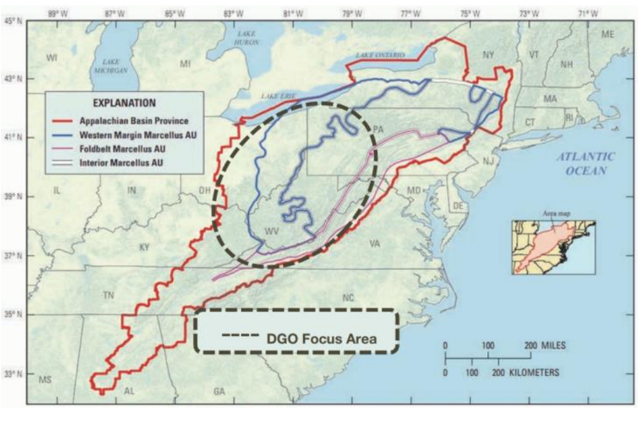


Source: Edison Investment Research. Note: *Low case defined as 15% higher costs and 15% lower gas price than base case. High case utilises 15% higher gas price and 15% lower costs than base case. Dividend yield based on cash dividend paid.

Appendix 1: Appalachian Basin gas producer

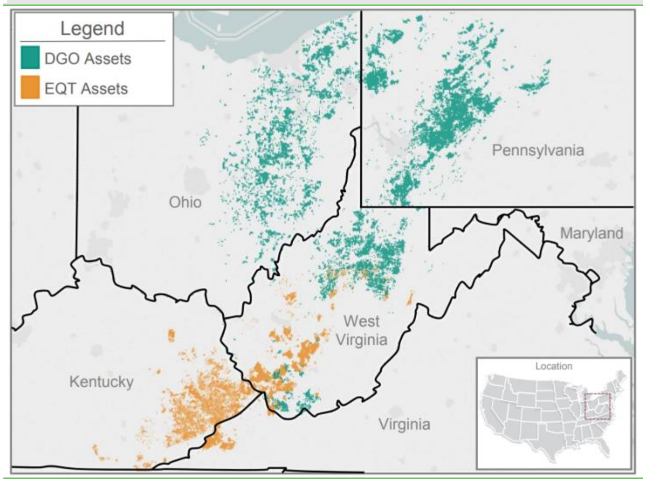
DGO operates within the Appalachian Basin, onshore in the northeast US. The basin covers an area of c 120m acres, underlying ten states, and has been a major producer of oil and gas from conventional vertical wells since the late 19th century. However, it has only come to prominence following the shale gas reserves discovery in 2009, known as the Marcellus Shale. Since then, the primary target of the Appalachian for most oil and gas companies has been the horizontal drilling of the Marcellus and Utica shale formations. DGO's main focus remains on conventional production from vertical wells.

Exhibit 33: Appalachian Basin



Source: DGO

Exhibit 34: DGO assets (June 2018)



Source: DGO

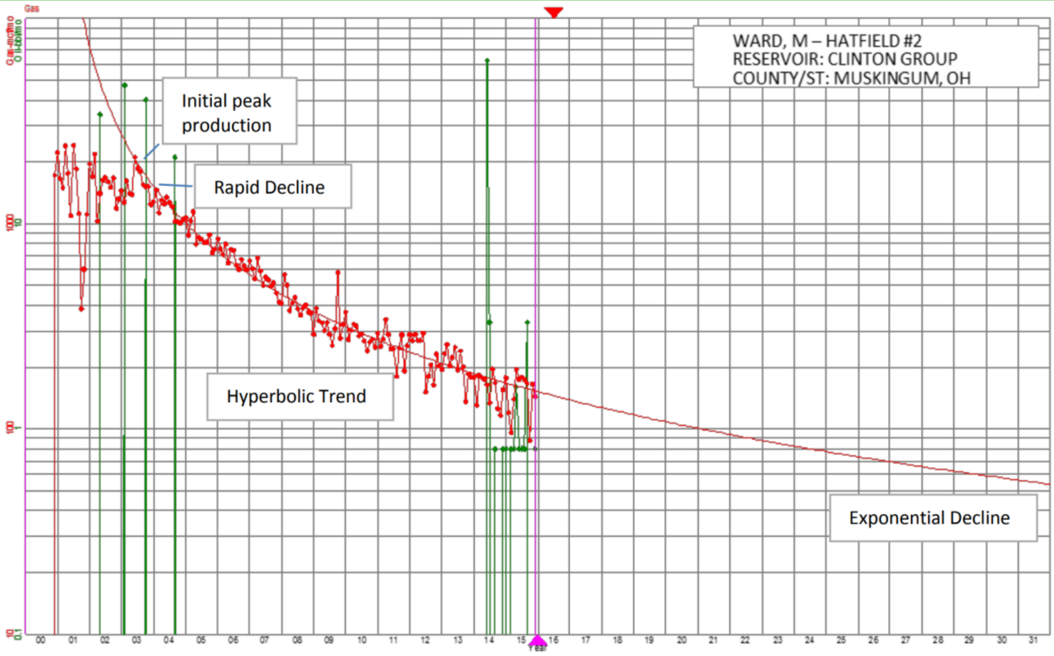
The depositions for the Appalachian Basin are the erosional sediments from the once Acadian Mountains into the lower basin. The basin was limited to the west by an uplift in rock formation from the Late Ordovician and through the Devonian period known as the Cincinnati Arch. As the mountains eroded, the sediment was deposited in the basin with alternating layers of carbonates, limestones, sandstone, siltstone and shale intervals. As a result of these geological events, the Appalachian Basin is very thin to the west and very thick to the south and east, varying from 1,500ft to 8,000ft thickness.

DGO's conventional wells, which comprise the vast majority of its current portfolio, are at shallow depths ranging from 2,200ft to 6,000ft (averaging c 4,000ft), with current production coming from the Devonian and Silurian ages. In Ohio, producing formations include the Berea, Bradford, Gants, Gordon, Rose Run and several other sands; however, the majority of the state production comes from the Clinton Sand. It is believed the Clinton Sand was formed as a nearshore deposit in the Silurian time. Its average depth is approximately 5,200ft, with depths ranging from 3,500ft to 6,000ft and a thickness of 150ft to 200ft with net productive pays ranging from 10ft to 100ft. The majority of production in Pennsylvania and West Virginia is from Devonian and Mississippian formations. In Pennsylvania, the major productive formations include the Balltown, Bayar, Bradford, Elk, Fifth, Sheffield Speechley, Tiona and Warren, and in West Virginia include the Alexander, Balltown, Benson, Big Injun, Big Lime, Elk, Fifth, Gordon, Riley and Warren. In general, the thickness for these reservoirs ranges from 5ft to 25ft for any individual zone, with a cumulative net sand thickness ranging from 40ft to 100ft.

The Marcellus Shale is a Devonian age formation, but due to its low porosity and extremely low permeability, has not been considered a major drilling target until 2009. Vertical wells in the Marcellus produce low volumes over a long life. Since 2009, through horizontal drilling the Marcellus has received a great deal of attention for its extremely high production rates, large estimated ultimate recovery volumes, and the statistical repeatability of the producing wells. Very large hydraulic fracture treatments are needed to make these commercial.

Drilling and completion operations are relatively straightforward with a low risk, due to the geology and extensive mapping of the formations, and consequently low cost with wells costing approximately $200,000. The producing wells are mature and expected to produce for 40–50 years with low-decline rates, averaging 3–5% per year with a low water content. Several of these wells are completed in multiple formations and production is commingled in the wellbore, therefore there is a potential upside for most of these wells because they may have additional productive formations up-hole from the existing producing formations and may allow for future completion opportunities and revenues.

Exhibit 35: Well Hatfield 2 type curve



Source: DGO

Midstream assets acquired

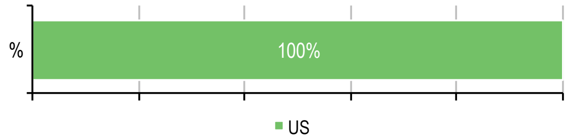
The EQT acquisition includes a gathering and compression system consisting of approximately 6,400 miles of pipeline and 59 compression stations in Kentucky, Virginia and West Virginia. These pipelines gather gas from EQT assets along with third-party gas from different operators in the region and deliver the aggregated volumes to Langley, Kentucky. Third-party access to EQT midstream facilities has been generating stable revenues of approximately $9m a year. Approximately 100mmcfd of gas from EQT assets is exported to Langley for NGLs processing. Once the NGLs are separated from the gas stream, the dry gas can be exported to multiple interconnections through the Big Sandy pipeline maximising its pricing and value. The value of mid-stream assets in our valuation is reflected in the netback DGO receives for its gas sales, which would otherwise be higher if they were reliant on third-party infrastructure.

Exhibit 36: Financial summary

US$m	2016	2017	2018e	2019e	2020e
Year-end December	IFRS	IFRS	IFRS	IFRS	IFRS
PROFIT & LOSS					
Revenue	17.1	41.8	215.2	370.8	360.4
Cost of sales	(15.3)	(27.9)	(97.6)	(151.7)	(145.4)
Gross profit	1.7	13.9	117.5	219.1	215.1
General & admin	(2.8)	(8.9)	(14.2)	(23.9)	(23.0)
EBITDA	26.5	23.2	113.8	212.7	208.9
Depreciation	(4.0)	(7.0)	(10.9)	(17.9)	(17.2)
Operating Profit (before amort. and except.)	22.5	16.2	102.9	194.8	191.6
Intangible amortisation	-	-	-	-	-
Exceptionals	-	-	-	-	-
Other	-	-	-	-	-
EBIT	22.5	16.2	102.9	194.8	191.6
Net interest	10.1	(11.5)	(32.4)	(44.0)	(36.5)
Profit Before Tax (norm)	32.5	4.7	70.5	150.8	155.2
Profit before tax (FRS 3)	32.5	4.7	70.5	150.8	155.2
Tax	(14.8)	4.1	-*	-*	-*
Profit After Tax (norm)	32.5	9.2	70.5	150.8	155.2
Profit after tax (FRS 3)	32.5	8.9	70.5	150.8	155.2
Average number of shares outstanding (m)	42.0	120.1	416.4	506.8	506.8
EPS - normalised (c)	44.2	7.7	16.9	29.8	30.6
EPS - normalised fully diluted (c)	34.3	5.6	12.3	21.6	22.2
EPS - (IFRS) (c)	42.1	7.4	16.9	29.8	30.6
Dividend per share (c)	-	4.0	8.0	11.2	11.2
Gross margin (%)	10.2	33.2	54.6	59.1	59.7
EBITDA margin (%)	155.0	55.5	52.9	57.4	57.9
Operating margin (before GW and except.) (%)	131.4	38.8	47.8	52.5	53.2
BALANCE SHEET					
Non-current assets	81.1	198.3	1,090.3	1,088.7	1,087.2
Intangible assets	76.8	190.4	1,082.3	1,080.7	1,079.2
Tangible assets	3.3	6.9	6.9	6.9	6.9
Investments	1.0	1.0	1.0	1.0	1.0
Current assets	4.7	30.3	65.2	65.2	65.2
Stocks	-	-	0.0	0.0	0.0
Debtors	3.1	13.9	13.9	13.9	13.9
Cash	0.2	15.2	50.0	50.0	50.0
Other/ restricted cash	1.4	1.3	1.3	1.3	1.3
Current liabilities	(38.5)	(15.3)	(15.3)	(15.3)	(15.3)
Creditors	(11.3)	(15.0)	(15.0)	(15.0)	(15.0)
Short term borrowings	(27.2)	(0.4)	(0.4)	(0.4)	(0.4)
Long term liabilities	(38.2)	(123.1)	(593.6)	(498.0)	(398.1)
Long term borrowings	(10.1)	(70.6)	(403.1)	(290.2)	(171.2)
Other long-term liabilities (inc. decomm.)	(28.1)	(52.5)	(190.6)	(207.9)	(226.9)
Net assets	9.2	90.2	546.5	640.5	738.9
CASH FLOW					
Operating cash flow	5.1	6.9	97.9	186.0	191.4
Capex inc acquisitions	(9.2)	(93.1)	(781.8)	(16.3)	(15.7)
Other	0.1	-	-	-	-
Equity issued	-	77.0	420.0	-	-
Dividends	(1.0)	(5.8)	(33.7)	(56.8)	(56.8)
Net cash flow	(4.9)	(15.0)	(297.6)	112.9	119.0
Opening net debt/(cash)	42.8	37.1	55.8	353.4	240.5
HP finance leases initiated	-	-	-	-	-
Other	10.7	(3.8)	-	-	-
Closing net debt/(cash)	37.1	55.8	353.4	240.5	121.6

Source: Diversified Gas & Oil accounts, Edison Investment Research. Note: *Company indication – net operating losses to shelter cash tax through to 2020.

EDISON

Contact details	Revenue by geography
Diversified Gas & Oil 1100 Corporate Drive Birmingham, Alabama 35242 United States 1-205-408-0909 www.diversifiedgasandoil.com/	

Board members

Non-executive chairman: Robert Marshall Post	Chief executive officer: Robert ‘Rusty’ Russell Hutson, Jr
Mr Post has been the non-executive chairman since 2017. He has more than 20 years’ experience in the industry. Mr Post has a BS degree in accounting from Jacksonville State University, Alabama.	Founder and CEO, Rusty Hutson Jr is the fourth generation in his family to immerse himself in the oil and gas industry. He graduated from Fairmont State College (WV) with a degree in accounting and earned his CPA License (Ohio). Prior to founding DGO in 2001, Rusty spent 13 years steadily progressing into multiple leadership roles at well-known banking institutions such as Bank One and Compass Bank. His final years in the banking industry were spent as CFO of Compass Financial Services.
Chief operating officer and finance director: Bradley Grafton Gray	**Senior independent non-executive director: David Edward Johnson**
Prior to joining the company in 2016, Mr Gray worked in the petroleum distribution industry and held Executive Vice President and CFO positions. Mr Gray has a BS degree in accounting from the University of Alabama and is a licensed CPA	Mr Johnson has enjoyed a long and successful career in the investment sector and is a non-executive director of AIM-quoted Bilby, a holding company providing a platform for strategic acquisitions in the gas heating and general building services industries.
Independent non-executive director: Martin Keith Thomas	
Martin Thomas is a partner in the corporate team of the law firm Wedlake Bell LLP in London. During his legal career of 30 years, Martin has also held senior management positions including seven years as the European managing partner of a global law firm in the US.	

Principal shareholders	(%)
Sand Grove Capital Management	8.88
Premier Asset Management	6.86
BlackRock	5.50
Miton Group	5.50
Man Group	4.14
Hutson, Robert Russell	3.95
Post, Robert	3.95
Pendal Group	3.46
Standard Life Aberdeen	2.84
Banco Santander	2.64

Companies named in this report

Antero Resources, Cabot Oil & Gas, Chesapeake, Devon Energy, EQT, Range Resources, Southwestern Energy, XTO