Challenger Energy

Emerging South Africa shale story

Initiation of coverage

Oil & gas

Challenger Energy (CEL) offers pure-play exposure to a frontier shale area, South Africa's Karoo basin. The Karoo, the world's eighth largest shale gas deposit, is estimated to contain 390tcf of recoverable gas by the EIA and has attracted interest from supermajors Shell and Chevron. South Africa's worsening energy shortage implies significant latent gas demand, and President Zuma has described shale as a "game changer" for the country. CEL was first mover in the basin, applying for a licence surrounding a key well that flowed gas in the 1960s. Its EV of A$29/acre is consistent with Australian pre-feasibility farm-out valuations, though CEL is arguably more advanced given the original well success. On 26 October the government announced it was proceeding with the licence applications. A licence award, expected in Q115, would remove timing uncertainty and pave the way for a farm-out. These milestones could lead to a near-term re-rating, with longer-term upside based on drilling success.

Year end	Revenue (A$m)	EBITDA (A$m)	PBT* (A$m)	Operating cashflow (A$m)	Net cash/(debt) (A$m)	Capex (A$m)
06/12	0.5	(9.3)	(9.4)	(0.9)	0.5	(9.4)
06/13	0.1	(7.6)	(7.6)	(0.6)	0.3	(0.3)
06/14e	0.1	(1.3)	(1.2)	(1.2)	0.8	0.0
06/15e	0.0	(2.5)	(2.4)	(1.2)	(0.5)	0.0

Note: *PBT is normalised, excluding intangible amortisation and exceptional items.

South Africa shale: An emerging story

Using Energy Information Agency estimates, CEL could be sitting on over 8tcf of gas, with upside from the Upper Ecca shales. Importantly, CEL's acreage surrounds the only well that flowed gas without stimulation from the Upper Ecca, materially reducing geological risk. Shell/CVX's presence in neighbouring blocks highlights the play's materiality, and their progress should be monitored for read-across.

Next steps for gas monetisation

South Africa's fracking moratorium was lifted in 2012, but applications are on hold pending publication of new technical regulations and mineral resources legislation. The country's acute energy crisis, evidenced by rolling black-outs, means there are strong political incentives for accelerating shale exploration. Gas offers an attractive alternative to coal in powergen, and demand growth could allow for reasonably high domestic gas prices. Following permit awards, three or four years of appraisal are needed before commercialisation is sanctioned. The proximity of major power infrastructure to CEL's area could help fast-track initial gas-to-power monetisation.

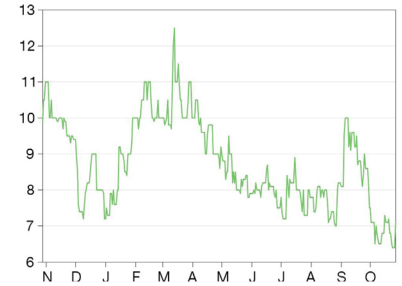
Valuation: Appraisal and farm-outs to create value

CEL's valuation of A$29/acre is equivalent to pre-feasibility acreage pricing featured in Australian farm-out deals. This leaves significant upside potential given partial de-risking from one well and CEL's strategic value as the only Karoo shale pure-play. Encouragingly, CEL's application was allowed to proceed on 26 October. The key near-term catalysts are a licence award and farm-out to fund exploration. A follow-on farm-out would likely attract much higher valuations (A$250-1,000/acre).

28 October 2014

Price	**A$0.071**
Market cap	**A$23m**
	A$1.13/US$
Net cash (A$m) as of 30 June 2014	0.8
Shares in issue	323.9m
Free float	85%
Code	CEL
Primary exchange	ASX
Secondary exchange	N/A

Share price performance



%	1m	3m	12m
Abs	(17.4)	(2.7)	(29.0)
Rel (local)	(19.3)	(0.4)	(29.7)
52-week high/low		A$0.13	A$0.06

Business description

Challenger Energy is an ASX-listed E&P with a 95% interest in an application for an exploration permit in the Karoo basin, South Africa, which is prospective for shale gas. It is awaiting award of a permit to start drilling.

Next events

Exploration permit award	Early 2015
Farm-out	2015
Drilling starts	2016

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Edison profile page

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Investment summary

Company description: South Africa shale gas pure-play

Challenger is an ASX-listed E&P with a 95% interest in a 1m acre licence application in South Africa's Karoo basin, estimated to hold 390tcf of recoverable shale gas resources by the EIA in May 2013. Activity has been on hold after a moratorium in 2011-12, but momentum is building towards the award of exploration permits, expected in early 2015. South Africa's severe power generation deficit and aging coal-based infrastructure means there are strong political incentives to allow gas shale exploration to go ahead, as gas offers a more economic alternative to coal. While the Karoo is underexplored, Challenger has a significant first-mover advantage as its permit application surrounds a well, drilled in the late 1960s, that flowed gas unstimulated to the surface. Following permit awards, CEL estimates it would take three or four years of appraisal before commercialisation via power generation goes ahead. This may be preceded by small-scale wellhead power generation.

Valuation: Farm-out deals to push value higher

Australian shale farm-in valuations provide useful, though imperfect, benchmarks for explorers in emerging shale basins like Challenger. Under this framework, the stock's implied EV valuation of c A$29/acre is consistent with deal valuations seen in pre-feasibility Australian basins, although CEL is arguably already in the 'feasibility' bucket given the original well success. Moreover, South African acreage should attract a premium to Australia given better infrastructure availability and lower fiscal take. A farm-in deal could crystallise this value before the exploration programme starts. Challenger offers strategic value to investors and farm-in partners as it has a high working interest and is the only pure-play E&P in South Africa shale. If the first well is successful, a second farm-out would be needed and would likely be executed at much higher valuations ($250-1,000/acre).

Financials: Farm-out to provide liquidity

Challenger held cash of A$0.8m as of end-June 2014. Its strategy is to keep a low cash burn rate while awaiting a licence award, with periodic modest equity top-ups to fund G&A. We note CEL successfully executed both a private placement and a fully underwritten option issue at a A$0.20 strike price in the past year. Challenger's proposed exploration and appraisal programme could cost A$20-25m on our estimates. A farm-out should fund the bulk of the initial E&A programme.

Sensitivities: Risks and opportunities

(1) **Geological**: Challenger's acreage contains one discovery well, and old 2D seismic data is also available. More appraisal is needed to assess well productivity, response from fracking and resource upside from the Upper Ecca shales. (2) **Permitting/regulatory**: After a long wait, momentum is building toward licence awards and new legislation is expected to be supportive to the nascent oil and gas industry in South Africa. The exact timing of licence awards remains fluid, but lifting this uncertainty would likely lead to a re-rating. (3) **Commercial**: Although ultimate gas price realisations are uncertain, newbuild generation economics favour gas over coal. A domestic gas supply source could give a significant boost to South Africa's economy.

Catalysts

The award of an exploration permit, expected in early 2015, is the key near-term catalyst. We would expect a first farm-in to take place shortly thereafter. As a small, nimble pure-play, Challenger should be able to progress G&G work quickly, with the first well expected to be drilled a year after the permit award. Progress by Shell and Falcon/Chevron could also bring interesting read-across.

South Africa shale gas pure-play

Challenger Energy is an Australia-listed E&P with a 95% working interest in a permit application in the Karoo basin. The Karoo basin contains an estimated 390tcf of shale gas prospective resources according to the US EIA, and has seen rising industry interest in recent years. Challenger was the first to apply for an exploration right in 2008. In 2010 Challenger replaced this application with the current application for on a block covering 1m acres, which management estimates could contain over 7tcf of risked recoverable reserves. Shell and Falcon's exploration right applications followed shortly thereafter. Falcon subsequently announced a deal with Chevron in December 2012.

South Africa shale activity is set to pick up after a three-year hiatus caused by a hydraulic fracking moratorium and delays in new regulations and mineral resources legislation.

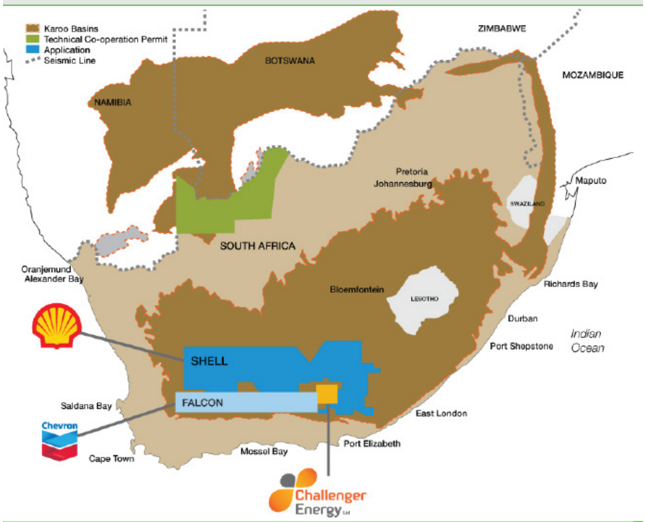
Karoo basin prospectivity

Geology

Challenger's acreage is located in the southern portion of the Karoo basin, a major sedimentary basin that covers nearly two-thirds of the country. The prospective zones for hydrocarbons are the early Permian-age Lower Ecca and Upper Ecca groups, organic-rich mature black shales of marine origin.

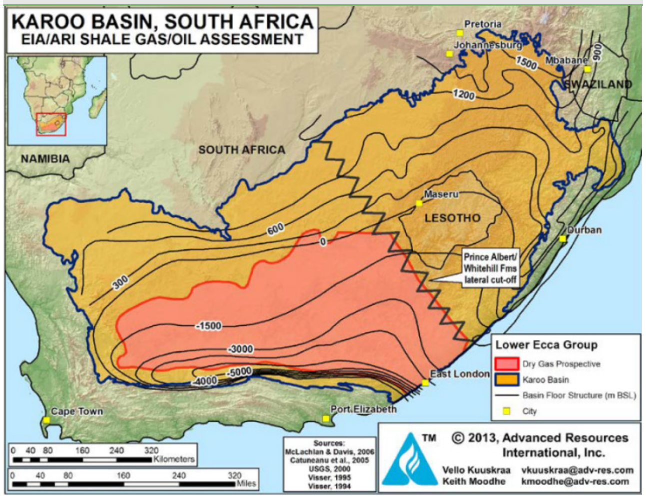
The Lower Ecca group contains the Prince Albert, Whitehill and Collingham formations, estimated to contain 390tcf by the EIA in its May 2013 World Shale Gas report. Importantly, this estimate does not include a resource assessment for the Upper Ecca group, as its lower Total Organic Content (TOC) is estimated to be below the agency's 2% threshold. The Upper Ecca contains the Fort Brown and Waterford Formations and flowed gas in the well in CEL's application area, providing upside potential. Challenger intends to target both the Lower and Upper Ecca shales in its upcoming exploration programme.

Exhibit 1: Challenger Energy acreage in Karoo basin and its neighbours Shell and Falcon Oil & Gas



Source: Challenger

Exhibit 2: Karoo basin: Lower Ecca shales dry gas prospective area

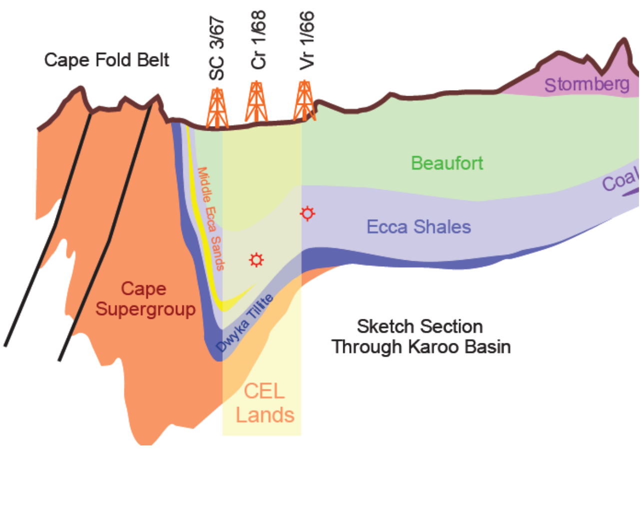


Source: EIA

The depth to the **Lower Ecca** shale ranges from 5,200ft (1,600m) to 10,500ft (3,200m), averaging around 8,000ft (2,450m). All three formations of the Lower Ecca group are thermally mature and firmly located in the dry gas window. The shales are thought to be over pressured, a feature usually associated with higher gas concentration in the reservoir and better gas recovery. Their low clay content is another positive feature, as it tends to makes hydraulic stimulation more effective. Net organic-rich thickness averages 300ft (90m). The EIA sees the Whitehill formation as the most prospective of the three with an average TOC of 6% and some areas showing TOC of 15%. The Collingham and Prince Albert shales have similar properties to the Whitehill shale except for their lower average TOCs of 4% and 2.5% respectively, although local maximums of 12% and 8% have been recorded.

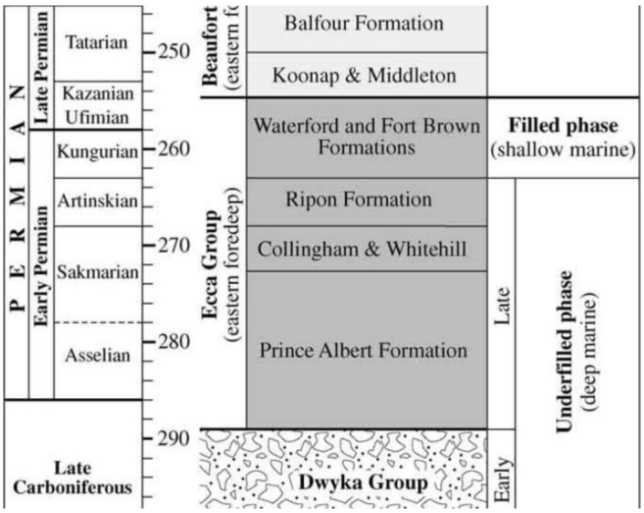
In contrast to the Lower Ecca laid down in a deep marine setting, the **Upper Ecca** shales were deposited in a shallow marine or lacustrine environment. Sediments deposited in shallow marine environments are typically coarser-grained than in deep marine settings. The Upper Ecca shales have a net organic-rich thickness of 700ft (210m) TOC of 1% to 2%, and are in the wet gas window due to their lower thermal maturity. Indeed, logs from the well in Challenger's acreage (CR 1/68) indicate the presence of butane and propane.

Exhibit 3: Geological cross-section of Karoo basin; historical wells drilled in the Ecca shales



Source: Challenger

Exhibit 4: Stratigraphic column of the Karoo basin



Source: EIA

One of the key geological risks in the Lower and Upper Ecca shales are igneous intrusions (called sills), ie layers of volcanic rock intruding between the sedimentary rock layers along pre-existing fractures and bedding planes. The presence of hot magma in organic-rich rocks transforms the organic matter into graphite and CO_2. Volcanic intrusions also reduce the quality of seismic imaging. Having said this, exploration risk is localised as this metamorphism takes place close to the intrusions and the sills are relatively easy to identify on aeromagnetic data. The entire Karoo basin is prone to sills of dolerite and kimberlite, with the thickest sills concentrated in the Upper Ecca group. We note the EIA factors in the sill intrusions in its 390tcf resource estimate, which it reflects in its recovery factor and prospective area calculations.

Drilling history

Geological data on the Ecca group is limited as only a handful of wells were drilled. Challenger's acreage is located around the only well drilled in the Karoo basin that flowed significant amounts of gas to the surface. In 1968 the South African state oil and gas company SOEKOR drilled a deep vertical well in the southern Karoo basin (Cranemere 1/68) down to the basement to test the deeper Bokkeveld group, encountering several gas shows.

While drilling in the Fort Brown shale interval of the Upper Ecca group, the well encountered high pressure that was subsequently interpreted as coming from the fractured Upper Ecca shale. The well threatened to blow out at a depth of 8,300ft (2,500m) and required activation of the blowout preventers and a mud well kill operation to bring it under control. It recorded an average flow rate of 1.84mmcfd during a 24-hour drill-stem test (DST) and a maximum controlled rate of 8mmcfd. Encouragingly, the latter is comparable to initial flow rates in horizontal fracked wells seen in established US shales such as the Marcellus and Eagle Ford, where companies are reporting 30-day initial production rates in a wide range of 3-21mmcfd, with an average around 8-9mmcfd.

Continuous cores were collected from the CR 1/68 well. Two other wells (VR 1/66 and SC 3/67) were drilled in the vicinity (though outside the boundaries of CEL's current block) and encountered hydrocarbons, but did not flow gas to the surface, possibly because the wells did not intersect natural fractures in the Upper Ecca section.

Additionally, four deep wells were drilled within Falcon's block in the late 1960s by SOEKOR. The wells reported gas shows but did not flow to the surface. Falcon's primary target is the Whitehill formation in the Lower Ecca, rather than the Fort Brown interval.

Substantial undiscovered risked resource potential

Exhibit 5: Shale gas reservoir properties and resources of the Karoo basin

	Risked in place (tcf)	Risked recoverable (tcf)	Recovery factor	Average depth (ft)	Average depth (m)	Net thickness (ft)	Net thickness (m)	Net to gross (%)	Avg TOC (%)	Avg thermal maturity	Composite success factor (%)
Lower Ecca shales											
Prince Albert Shale	385	96	25%	8,500	2,591	120	37	30%	2.5%	3%	15%
Whitehill Shale	845	211	25%	8,000	2,438	100	30	50%	6%	3%	24%
Collingham Shale	328	82	25%	7,800	2,377	80	24	40%	4%	3%	15%
Upper Ecca shales											
Fort Brown	N/A	N/A		6,000	1,829	600	183	20%	<2%	1.1%	N/A
Waterford Shale	N/A	N/A		4,500	1,372	100	30	20%	<2%	0.9%	N/A
Total	**1,559**	**390**	**25%**								**19%**

Source: EIA

In the table below, we show a summary of companies' exposure to the Karoo basin. Using the EIA estimate of 390tcf of total recoverable gas in the prospective area (with a 19% average geological risking) and assuming an even distribution of resource density across the area, Challenger would have over 8tcf of risked recoverable gas. Crucially, company management believes there is upside to the EIA figures as (1) its acreage surrounds a discovery well (CR 1/68), making it less risky than neighbouring areas, and (2) the EIA figures exclude the Upper Ecca shales despite the fact that they flowed gas in the CR 1/68 well.

Exhibit 6: Karoo basin exposure by company

	Square km	Acres (000s)	% of total prospective area	Potential risked recoverable (tcf)
Challenger Energy	3,238	800	2%	8.1
Falcon Oil & Gas/Chevron	30,328	7,494	19%	75.8
Shell	95,000	23,475	61%	237.5
Total applications in prospective area	**128,565**	**31,775**	**82%**	**321.4**
Total prospective area	**155,865**	**38,515**	**100%**	**390**
Total Karoo basin area	**3,871,617**	**956,687**		

Source: Challenger, EIA, Edison Investment Research. Notes: Challenger applied for ~1m acres, but expects to be awarded 800,000 acres to allow for game parks. Shell has a Technical Cooperation Permit for 45.7m acres but applied for exploration licences covering 23.5m acres.

Work programme and timeline

Very little geological and geophysical work has been done to date, as Challenger is keen to receive a permit before spending significant sums of money. After it receives an exploration permit (more on this below), Challenger will reprocess existing 2D seismic data shot in the 1960s and 1970s and acquire two coreholes. Thereafter, it plans to drill one vertical well, possibly near the original CR 1/68 well, fracture it in three stages and run a production test.

The company has not provided an estimate of the cost of the initial exploration work. We estimate the entire programme could cost around A$20-25m, including c A$15m to drill, frack and test one well, and A$5-10m for seismic reprocessing and coreholes drilling and analysis. We think a multi-stage fracked vertical well will initially cost two to three times more than the <A$5m it would in the

US due to the lack of service availability (rigs, pressure pumping) in South Africa. Equipment can be imported from the US, but this will mean additional costs in terms of transport and mobilisation. These costs could potentially be mitigated by sharing logistics with Shell and Falcon/Chevron.

If the initial work programme is successful, we expect Challenger to continue appraisal activity to move from the 'proof of concept' phase to technical and economic validation of the project. A new seismic survey may be necessary to define a drilling programme and particularly the location of natural fractures and 'sweet spots'. More drilling (including horizontal wells) and analysis will be needed to test lateral reservoir continuity and understand how the rocks respond to hydraulic stimulation. Consistent flow rates and estimated ultimate recoveries (EUR) are crucial before final investment decisions (FID) are taken. We would expect a follow-on appraisal programme to cost around A$50-100m.

Commercial considerations

In addition to below-ground risks, there are above-ground uncertainties including permitting, regulatory and gas commercialisation issues, as one would expect in an early-stage play.

Still awaiting an exploration permit: Potential award in early 2015

Concerns about the environmental and economic impact of shale gas drilling has led to a lengthy consultation and legislative process in South Africa to ensure a) safe and socially responsible drilling practices and b) an equitable sharing of the economic rent between all stakeholders. While this approach is quite sensible, it has led to delays in permit awards historically.

However, momentum in favour of shale has picked up in the last few months, and the South African government has been increasingly supportive of shale gas exploration given the large potential economic benefits. The issue now is about 'when' not 'if' the permits will be awarded. A 2012 Shell-commissioned report by consultancy Econometrix estimated that a 50tcf gas development could add around $18bn to the economy annually, equivalent to c 5% of GDP, and reduce unemployment (currently officially at 25.5%) by 4.2%. Indeed, President Jacob Zuma and his mineral resources ministers have issued positive statements on shale gas in the past year. President Zuma has called shale gas a 'game-changer' for South Africa's economy, and the secretary general of the ANC (African National Congress, South Africa's ruling party) has stated that shale gas drilling 'must be done' as the country 'needs it'.

There are strong indications that the government is ready to move forward with shale exploration. On 26 October 2014 South Africa's Petroleum Agency (PASA) advised that it is proceeding with processing Bundu's (Challenger's local subsidiary) application for a shale gas exploration right. Challenger is now required to update its environmental management programme and consult with concerned stakeholders by the end of February 2015.

- **Technical regulations**: Challenger was the first company to file an application for an exploration right in the Karoo basin in 2008 (later replaced by an application for a larger 1m acre block), followed by Falcon and Shell in 2010. The public outcry that followed Shell's application led to the introduction of a moratorium on licensing and exploration in April 2011. The moratorium was lifted in September 2012, but applicants were only allowed to proceed with geological studies until technical regulations for unconventional resources are approved. The first draft of the regulations covering drilling, fracking and environmental specifications was published in October 2013 for public consultation. There remains opposition to drilling and fracking in the Karoo from environmental groups and landowners, especially on the issue of water management; although the debate has now become more balanced. The regulations are yet to be finalised and approved, but the minister of mineral resources expects to undertake further stakeholder consultation and to publish them in the next few weeks.

- **Mineral resource legislation:** Separately, an amendment to the country's mineral resources legislation (MPRDA) in November 2013 proposed to give the state a right to take a 20% free carry in all projects and to buy part or all of the remaining 80% share at an agreed price. The amendment was widely criticised by energy companies and many in business and political circles. The bill was passed by parliament in March 2014, but has not yet been signed off by President Zuma. The new minister of mineral resources appears open to make the terms more appropriate to encourage the nascent oil and gas industry, and has requested the president not sign off pending a review, which is due out shortly. There is a general expectation in the industry that the revised version of the amendment will be more favourable to the oil companies.

It is unclear if the final MPRDA bill and technical regulations will be approved by end 2014, although it is likely that this will be moved forward in parallel with processing the applications. While Falcon Oil & Gas expects to be awarded an exploration permit by year end, Challenger management is more cautious on timing.

Current fiscal terms are favourable to gas and oil development, with a royalty rate of 7% and corporate income tax of 28%. To date, there has been no debate on the tax and royalty rates.

Rising gas usage in power sector key to monetisation

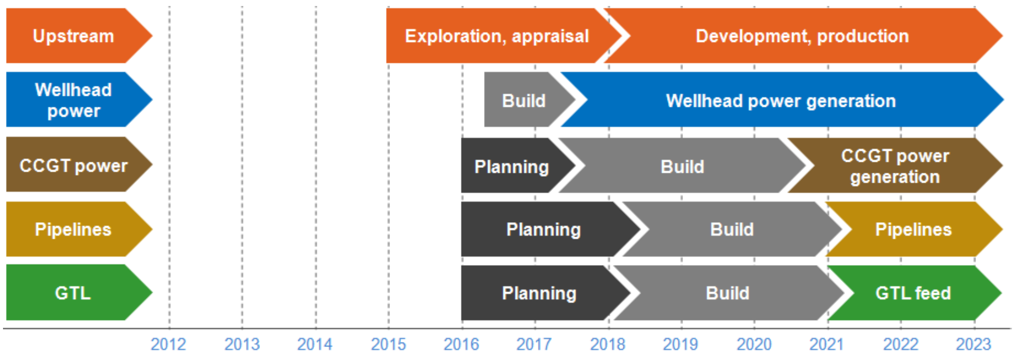
South Africa's gas market is embryonic: gas makes up only 3% of the primary energy mix (vs a 21% global average) and coal represents 72% of primary energy. This presents both upside for natural gas penetration in power and industrial markets, and some commercialisation risks.

The country consumes four times its domestic production of 107bcfd annually. The shortfall is imported by an 865km pipeline from northern Mozambique operated by Sasol. Most of the gas is used in Sasol's and PetroSA's gas-to-liquids (GTL) plants and by industrial companies. Low historical domestic supply and lack of infrastructure (transmission and distribution network, processing facilities), particularly in the Western and Eastern Cape, constrain the role of gas in the electricity and industrial sectors. Routes to monetise new gas supplies include:

- **Power generation**: South Africa suffers from regular power shortages caused by a historical underinvestment in baseload coal-fired generation capacity. State-owned electricity company Eskom, which controls 97% of the country's generating capacity, has been forced to implement blackouts more frequently in recent years, and has required equity injections from the state. Further support is likely to be necessary. Relying on diesel-fired generation for peak demand is costly, while importing LNG would be uneconomic.

  Challenger plans to initially monetise small amounts of gas using wellhead generators. Importantly, there is major existing power line and substation infrastructure close (60km) to Challenger's block, which could considerably facilitate the initial monetisation of gas in wellhead power generation. A successful small-scale power project would be a powerful demonstration of concept feasibility, and could pave the way for larger-scale gas combustion in combined cycle gas turbine (CCGT) plants at the start of the next decade.
- **Pipeline**: Other end-user markets (industrial, commercial, residential) could be reached if pipelines were built to the coast just 200km away. For example, the Coega industrial development zone (IDZ), close to the port facilities of Port Elizabeth, is aiming to attract investments in various sectors including automobile, chemical, refining and metals, but is materially constrained by a lack of power and would be a natural market for shale gas. Challenger estimates that new gas pipelines could start up in 2022-23.

Exhibit 7: Challenger's envisaged commercialisation timeline for gas



Source: Challenger, as of October 2014

- **Gas-to-liquids**: Existing GTL plants at Mossel Bay and Sasolburg will likely require gas back-fill to extend their lives. The coastal Mossgas plant is running below capacity due to declining domestic gas output. Longer term, plants could be expanded and new plants could be built.
- **Exports:** If sufficient amounts of gas are proved up, gas could potentially be exported by pipeline to neighbouring countries or by LNG in the long term. The Econometrix study highlights that the export market could eventually be bigger than domestic consumption. However, we would expect the priority to be firmly on domestic gas usage before LNG exports are considered.

These plans will require significant new gas and power infrastructure to be built. The South African government supports the goal of raising the share of gas in the energy mix, notably in the power sector where gas is expected to make up 14-29% of generating capacity in 2030, up from just 5% currently, according to the 2013 Integrated Resource Plan (IRP). A more detailed Gas Utilisation Master Plan should be released in the next few months.

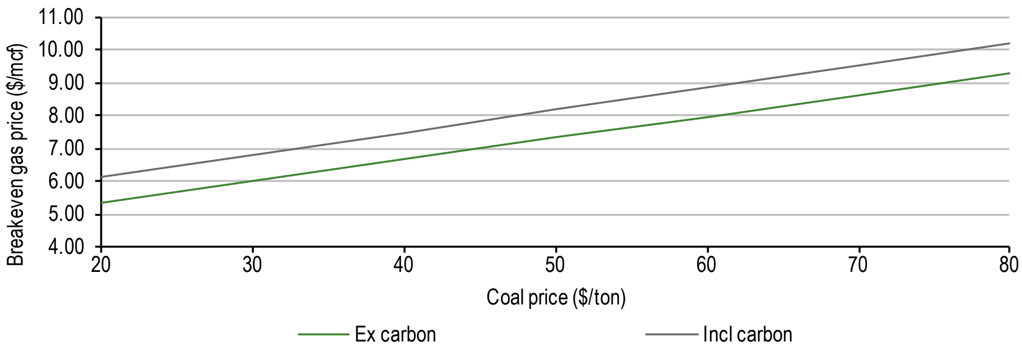
Newbuild power economics should allow for reasonable gas prices

There is uncertainty on gas pricing mechanisms and ultimate realisations, obviously a key factor in overall project economics. There is no traded gas market in South Africa and a near-monopoly of Sasol on gas imports and resale to distributors. We estimate Sasol's gas sales price averages around US$5/mcf, with a range of US$4-6/mcf depending on customers' access to alternative fuel sources. However, this price is unlikely to reflect the cost of new gas supplies, whether domestic or imported. The IRP assumes shale gas prices of $8.7/mcf in 2025, declining to $4.7/mcf by 2035 as domestic production increases.

From the perspective of potential customers such as Eskom or independent power producers (IPPs), it would make sense to build gas-fired capacity since full-cycle levelised electricity costs (including construction, operating costs and fuel) from gas-fired plants are below those for coal. Domestic coal is currently cheap, supplied to Eskom on a cost-plus basis at a price well below export prices ($22/ton domestic vs $71/ton export). However, many long-term contracts are rolling off in the next few years, leaving Eskom 40% uncontracted beyond 2017. Domestic coal prices are therefore likely to rise towards export parity over time.

The 2013 Integrated Resource Plan calculates that break-even gas prices (ie coal-gas price parity) for baseload generation could be in a range of $6-8/mcf assuming long-term domestic thermal coal prices of $30/ton (the IRP's base case) to $60/ton in an upside case scenario. The proposed carbon tax, to be implemented from 2016 onwards, would add c $0.8/mcf to gas break-even prices.

Exhibit 8: Coal equivalent gas pricing for newbuild base-load generation ($/mcf)



Source: Integrated Resource Plan 2013, Edison Investment Research. Note: The IPR refers to the coal-gas parity point as a 'gas breakeven price', not to be confused with an upstream economic breakeven.

Moreover, building new coal plants is proving expensive, as the cost overruns on Eskom's two coal plants under construction, Kusile and Medupi, are demonstrating. Ultimately, upstream producers and gas users will have to agree on acceptable price levels for both parties, ie high enough to remunerate production while offering an attractive alternative to coal and diesel for users. Fiscal incentives, the launch of a gas-to-power IPP programme similar to the existing Renewable Energy IPP programme, or carbon tax legislation could further encourage the construction of CCGTs.

If large amounts of gas are found, the South African market could develop in a fashion similar to the European/UK markets. Suppliers and offtakers signed long-term take-or-pay agreements in the 1970s and 1980s, initially for the residential and industrial markets. In the UK, significant gas-fired capacity was built in a short period of time in the 1990s (the so-called 'dash for gas').

Strategy: Farm-out before development

Challenger's strategy is to farm down its acreage (95% working interest) at some stage before full-scale development. In the absence of financing capability and cash-generating assets, junior E&Ps like Challenger typically have to farm down well before final investment decision (FID) (normally the optimal point to divest) to access funding and technical help from a larger partner. For instance, Falcon Oil & Gas entered into an agreement with Chevron in December 2012 to jointly seek exploration permits; Chevron reimbursed US$1m of past costs and participation levels in licences will be mutually agreed.

If exploration permits are awarded, we estimate Challenger will have to spend around A$20-25m on initial E&A work. The company will seek a farm-out deal likely including a full cost-carry and possibly past costs reimbursements, as this is generally a less dilutive and more efficient solution for shareholders than equity issues. Such a deal could be structured as a multi-stage farm-down contingent on performance milestones. Challenger has stated it is in 'advanced' farm-in discussions. Ahead of a farm-out deal taking place, the company may need small equity top-ups to cover general and administrative costs.

Management

Challenger's management has extensive experience in oil and gas. The addition of Robert Willes as MD in 2013 and Bill Bloking as non-executive director in 2014 strengthens the management team.

Michael Fry (non-executive chairman) has experience in capital markets, corporate treasury management and commodity, currency and interest rate risk. Michael was a founding director of

Challenger Energy and currently serves as its chairman. He is also chairman of Red Fork Energy and Norwest Energy.

Robert Willes (managing director, appointed 8 April 2013) has over 25 years' experience in oil and gas, primarily with BP. At BP he worked in M&A and gas negotiations in Europe. In Australia, Robert was BP's general manager of the North West Shelf LNG project. He had accountability for BP's interests in Browse and Gorgon LNG, and for business development in Asia-Pacific. More recently, Robert was CEO of Eureka Energy during its A$107m takeover by Aurora. He is also non-executive director of Buru Energy.

Bill Bloking (non-executive director, appointed 28 February 2014) has 40 years' experience, and has held senior positions with BHP Billiton and Exxon. He is chairman of Nido Petroleum and MD of Gunson Resources. He was previously chairman of Norwest Energy and MD of Eureka.

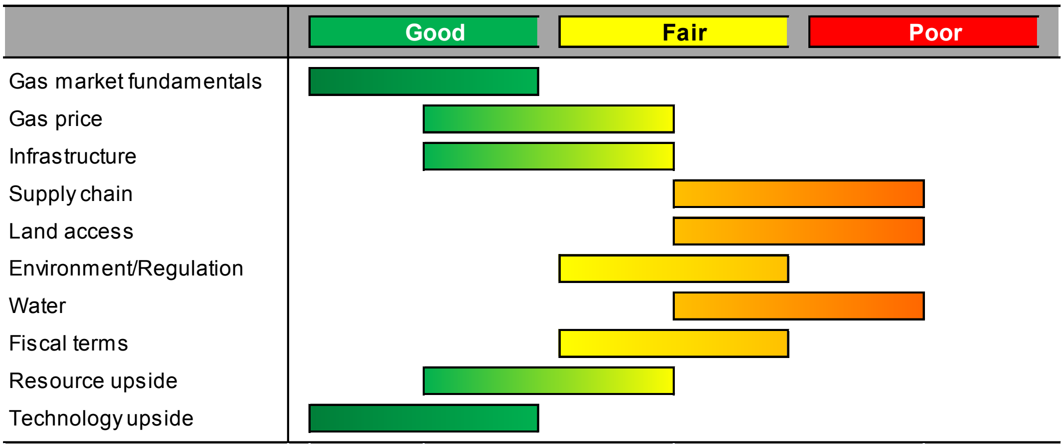
Paul Bilston, PhD (technical adviser) has 15 years' experience. He has worked at Worley, GHD, AGL Energy and AJ Lucas. His recent focus has been on unconventionals in Australia and overseas and he managed the Gloucester Gas project. He has a PhD in engineering.

Peter Price (Director, Bundu Oil & Gas Exploration Pty Ltd) has 55 years' experience. He has worked at Anglovaal, Anglo American, Lonhro, Rand Corp, Babcock and Molopo.

Sensitivities

- **Geological/technical risk**: the Karoo basin has considerable amounts of gas in place, but is still technically and commercially unproven. More drilling is needed to understand well productivity, hydraulic fracking response and upside from the Upper Ecca shales. Poor oil service availability could lead to high costs during the initial E&A phase, although costs should come down during the development phase.
- **Permitting/regulatory risk**: there are uncertainties on the timing of permit awards, although we are starting to receive clarity. The Petroleum Agency's decision in late October 2014 to start processing CEL's application is certainly an important step forward, suggesting an early 2015 resolution. There are risks if the government gets a 20% free carry in the project as per the MPRDA proposal, although the bill is unlikely to pass in its current form.
- **Commercial risk**: the most likely gas monetisation route is the power sector. There is no clarity yet on gas price realisations, but newbuild generation economics favour gas over coal and should allow for reasonably attractive domestic prices.

Exhibit 9: Challenger's view on technical, regulatory and commercial risks



Source: Edison Investment Research based on Challenger, as of October 2014

- **Funding risk**: a farm-out is required to fund the bulk of the proposed E&A programme in 2015-18. Ahead of a farm-out deal, Challenger may require small equity top-ups from existing shareholders to cover general and administrative costs, though this does not appear to be an issue given support from existing key shareholders.

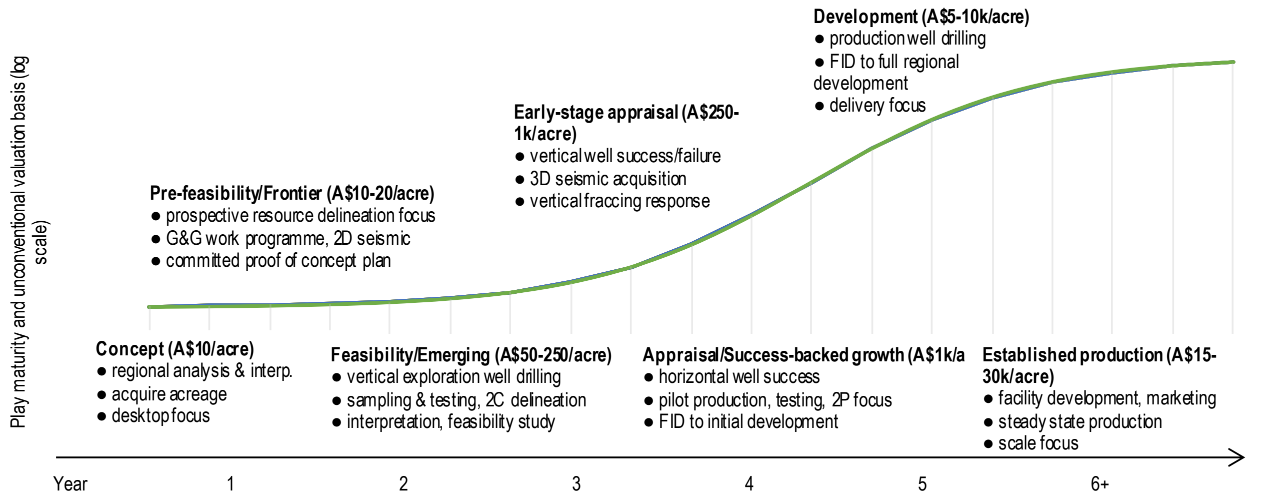
Valuation

As set out in our Oil & gas research principles, we normally value oil companies with an asset-by-asset NAV derived from detailed DCF modelling. Such a valuation includes production, development and contingent resources (core NAV), while exploration is valued only if there is a plan and resources to drill in the next 12-18 months (RENAV). However, for a frontier region explorer like Challenger, there is little basis for a reliable NAV valuation as the high risk discounting (in the low single digits) that would be applied to very large potential undiscovered resources would render results almost meaningless.

Going up the valuation S-curve

A more useful approach is to look at top-down metrics such as $/acre for unconventional plays. The S-curve below is a stylised illustration of the value uplift in Australian shale acreage valuations as the assets are de-risked over time. De-risking is typically a long process that requires substantial data acquisition as well as other forms of economic validation, eg third-party farm-outs.

Exhibit 10: Representative unconventional play/player maturation S-curve



Source: Edison Investment Research

Farm-outs and acquisitions from other regions with a rich M&A history such as the US and Australia provide useful valuation benchmarks for an acreage-rich explorer like Challenger.

It is fairly clear to us that the US shale experience and US-style multiples are currently not applicable to South Africa given the far earlier stage of development and lower infrastructure and service sector availability in South Africa. As a point of reference, US farm-out multiples range from US$3-5k/acre for appraisal plays (Mississippian Lime, Powder River) to US$15-30k/acre for plays in large-scale development (Eagle Ford, Haynesville). We note that US dry gas plays typically attract a c 45% discount to oily shales in farm-out deals.

We argue that the Australian example is more applicable, though evidently far from perfect. For reference, Australian shale farm-out multiples range from A$10-50/acre in frontier basins (Canning, Southern Georgina, Beetaloo) to A$150-1,000/acre for a more established play such as the Cooper basin. Farm-out deals in the Cooper basin announced in the past year (where terms have been disclosed) have attracted valuations of A$250/acre on average, with deals ranging from A$150/acre to around $430/acre (see Exhibit 11).

Exhibit 11: Cooper basin farm-out deal valuations – last 12 months

				Gross farm-out area	Acquirer stake	Inferred cost of farm-in to acquirer		Inferred 100% valuation of gross acreage	
Acquiror	**Vendor**	**Announced**	**Play**	**(acres)**	**%**	**US$m**	**A$m**	**A$m**	**A$/acre**
New Standard	Drillsearch	Dec-13	Cooper Basin	593,053	53%	43	47	89	149
Origin	Senex	Feb-14	Cooper-Eromanga Basins	1,184,376	45%	170	185	411	347
QGC	Drillsearch	Mar-14	Cooper Basin	500,000	60%	119	130	217	433
Drillsearch	Ambassador	May-14	Cooper Basin	593,053	48%	38	41	87	147
Magnum Hunter	Ambassador	Jun-14	Cooper Basin	593,053	48%	49	53	112	188
Last 12 months									**253**

Source: Edison Investment Research, company announcements

Below we attempt to list the key differences between the Australian and South African shale situations. Taking all of these factors into account and assuming geology and costs are similar, South African acreage should arguably be priced at a premium to Australia. Pinning down the extent of such a premium is premature and impossible to calculate at this stage.

- **(+)** Australian frontier basins tend to be remote, far from existing infrastructure or demand centres (400-1,000km), compared to Challenger's relative proximity to the coast (200km). The Karoo also benefits from the presence of existing power infrastructure, with Challenger's block only 60km from a major power substation.
- **(+)** The jury is still out on how gas prices in South Africa will compare to Australia. Assuming similar geology, costs and at $5.5/mcf gas prices (close to Sasol's current average sales price), we estimate that valuations for South African and Australian gas should be broadly similar. However, at a higher gas price of $8/mcf, which could be achievable given strong power demand, South African shale acreage should be priced at a material premium to Australian acreage, due to South Africa's lower tax take vs Australia.
- **(=)** There are fiscal, regulatory and environmental risks of different nature in both countries. While Australia has already awarded drilling permits, operators there are encountering opposition from stakeholders and in some cases outright bans on fracking, such as in New South Wales and Victoria. Australian explorers also face a less favourable political and economic context than in South Africa.
- **(-)** Some Australian basins have seen more conventional and/or shale exploration drilling to date than the Karoo. For instance, the Cooper basin is one of the more advanced shale plays in Australia with 60 wells drilled to date and several wells already in production.

Current valuation leaves significant upside potential

Challenger offers strategic and scarcity value as the only pure-play E&P in South Africa shale with a high (95%) working interest. In comparison with Falcon/Chevron's or Shell's acreage, it is arguably a lower-risk play due to the presence of the CR 1/68 gas discovery well in its block.

Challenger trades at an implied EV valuation of c A$29/acre, equivalent to farm-out deal valuations featured in frontier shale basins in Australia (A$10-50/acre). Its implied valuation would be A$23/acre if the company is awarded the full 1m acres it applied for instead of the 0.8m it expects to be awarded.

Where Challenger should sit on the farm-out valuation S-curve based on its current stage of maturation is subject to debate. The success of the original CR 1/68 well and existence of 2D seismic, albeit old, represents a meaningful degree of geological de-risking. On the other hand, Challenger has yet to reprocess existing 2D seismic data, shoot new seismic, conduct a feasibility study or delineate contingent resources, which requires more drilling. As such, the company is currently somewhere in the 'feasibility/emerging' stage, which has attracted a valuation range of

A$50-250/acre in past Australian farm-out transactions. As previously discussed, a premium to these deal multiples should apply for South Africa given a lower tax take and greater infrastructure availability.

It is important to note that the financial markets are normally willing to ascribe far less value to deal-backed assets than acquirers. In Australia, our analysis suggests equity markets pay just 15-20% of the entry price into assets that industry is prepared to pay. Put another way, pre-farm-out Australian emerging acreage tends to trade at a very steep discount (80-85%) to farm-out valuations. Whatever the exact extent of the discount, this points to a significant re-rating opportunity as and when a farm-in deal does take place, even if markets typically do not fully reflect farm-in multiples in share prices after a transaction. For investors, this wide valuation discount offers an opportunity to gain a foothold in long-term emerging stories like Challenger that offer substantial value accretion potential.

A premium to the current implied A$29/acre valuation is required to be value-accretive for Challenger at the current share price. Given company statements about being in ‘advanced’ farm-out discussions, we believe there are good reasons to be confident that exploration rights will be awarded and that attractive farm-out terms will be reached. Such a transaction could also potentially be structured as a multi-stage farm-out, with work programmes contingent on performance milestones.

If the first well is successful, a second stage farm-out would be needed to fund more extensive appraisal. This second deal would likely attract significantly higher $/acre multiples (A$250-1,000/acre), consistent with ‘early-stage appraisal’ valuations. After a two-stage farm-out process, we estimate that Challenger could retain a high minority share in the licence.

We intend to discuss farm-out economics in more detail in follow-up reports.

Financials

Challenger held A$0.8m in cash as of end-June 2014. Challenger requires funds to pay for ongoing G&A (A$0.6m spent in H114), and a well-funded joint venture partner to cover exploration and appraisal expenses. Covering G&A does not appear to be an issue as the company has been successful in raising equity in recent years, with a A$1m placement at A$0.06 in Q313 and a fully underwritten A$1m options issue in Q214 at a strike price of $0.20. Moreover, Challenger may not need equity top-ups if it is able to execute a favourable farm-out deal in the near future.

Strategically, we believe it may be in Challenger’s interest to raise equity *before* a deal to partly fund the first exploration programme, as it would retain a much higher working interest post-farm-out. Minimising dilution in the early stages would allow it to benefit more from a bigger value uplift in a second farm-out.

A larger equity issue may be easier to execute after a permit award and farm-out deal as Challenger’s share price would presumably be higher then, and could allow the company to minimise dilution in a second-stage farm-out.

Exhibit 12: Financial summary

	$'000s	2012	2013	2014e	2015e	2016e
June						
PROFIT & LOSS						
Revenue		509	89	58	0	0
Cost of Sales		(255)	0	0	0	0
Gross Profit		255	89	58	0	0
EBITDA		(9,307)	(7,567)	(1,256)	(2,472)	(1,236)
Operating Profit (before amort. and except.)		(9,311)	(7,570)	(1,256)	(2,472)	(1,236)
Intangible Amortisation		0	0	0	0	0
Exceptionals		0	0	0	0	0
Other		0	0	0	0	0
Operating Profit		(9,311)	(7,570)	(1,256)	(2,472)	(1,236)
Net Interest		(88)	4	46	47	(148)
Profit Before Tax (norm)		(9,400)	(7,566)	(1,210)	(2,425)	(1,384)
Profit Before Tax (FRS 3)		(9,400)	(7,566)	(1,210)	(2,425)	(1,384)
Tax		0	0	0	0	0
Profit After Tax (norm)		(10,039)	(8,544)	(1,351)	(2,425)	(1,384)
Profit After Tax (FRS 3)		(9,400)	(7,566)	(1,210)	(2,425)	(1,384)
Average Number of Shares Outstanding (m)		311.5	311.5	329.5	329.5	329.5
EPS - normalised (c)		(3.3)	(2.8)	(0.4)	(0.7)	(0.4)
EPS - normalised and fully diluted (c)		(3.3)	(2.4)	(0.3)	(0.6)	(0.3)
EPS - (IFRS) (c)		(3.0)	(2.4)	(0.4)	(0.7)	(0.4)
Dividend per share (c)		0.0	0.0	0.0	0.0	0.0
Gross Margin (%)		50.0	100.0	100.0	NA	NA
EBITDA Margin (%)		NA	NA	NA	NA	NA
Operating Margin (before GW and except.) (%)		NA	NA	NA	NA	NA
BALANCE SHEET						
Fixed Assets		13,567	4,870	4,772	4,772	11,422
Intangible Assets		0	0	0	0	0
Tangible Assets		13,567	4,870	4,772	4,772	11,422
Investments		0	0	0	0	0
Current Assets		631	394	844	82	82
Stocks		0	30	30	30	30
Debtors		116	82	51	51	51
Cash		515	282	762	0	0
Other		0	0	0	0	0
Current Liabilities		(342)	(217)	(115)	(115)	(115)
Creditors		(342)	(217)	(115)	(115)	(115)
Short term borrowings		0	0	0	0	0
Long Term Liabilities		(275)	(9)	(9)	(484)	(8,517)
Long term borrowings		0	0	0	(475)	(8,509)
Other long term liabilities		(275)	(9)	(9)	(9)	(9)
Net Assets		13,581	5,037	5,491	4,254	2,871
CASH FLOW						
Operating Cash Flow		(864)	(616)	(1,199)	(1,236)	(1,384)
Net Interest		0	0	0	0	0
Tax		0	0	0	0	0
Capex		(9,408)	(333)	(43)	0	(6,650)
Acquisitions/disposals		0	537	0	0	0
Equity Financing		4,534	180	1,721	0	0
Dividends		0	0	0	0	0
Net Cash Flow		(5,738)	(233)	479	(1,236)	(8,034)
Opening net debt/(cash)		(6,250)	(515)	(282)	(762)	475
HP finance leases initiated		0	0	0	0	0
Other		3	(0)	1	(1)	(0)
Closing net debt/(cash)		(515)	(282)	(762)	475	8,509

Source: Company reports, Edison Investment Research

EDISON

Contact details	Revenue by geography
Level 17, 500 Collins Street Melbourne, VIC, 3000 Australia +61 3 9614 0600 www.challengerenergy.com.au	N/A

CAGR metrics		Profitability metrics		Balance sheet metrics		Sensitivities evaluation	
EPS 11-14e	N/A	ROCE 14e	N/A	Gearing 14e	N/A	Litigation/regulatory	●
EPS 12-14e	N/A	Avg ROCE 11-14e	N/A	Interest cover 14e	N/A	Pensions	○
EBITDA 11-14e	N/A	ROE 14e	N/A	CA/CL 14e	N/A	Currency	◖
EBITDA 12-14e	N/A	Gross margin 14e	N/A	Stock days 14e	N/A	Stock overhang	○
Sales 11-14e	N/A	Operating margin 14e	N/A	Debtor days 14e	N/A	Interest rates	○
Sales 12-14e	N/A	Gr mgn / Op mgn 14e	N/A	Creditor days 14e	N/A	Oil/commodity prices	●

Management team

Managing director: Robert Willes (appointed 8 April 2013)

Robert Willes has over 25 years' experience in oil and gas, primarily with BP. He was BP's general manager of the North West Shelf LNG project. He had accountability for BP's interests in Browse and Gorgon LNG, and for business development in Asia-Pacific. More recently, Robert was CEO of Eureka Energy and managed its A$107m takeover by Aurora.

Non-executive chairman: Michael Fry

Michael Fry has experience in capital markets, corporate treasury management and commodity, currency and interest rate risk. Michael was a founding director of Challenger Energy and currently serves as its chairman. He is also chairman of Red Fork Energy.

Non-executive director: Bill Bloking (appointed 28 February 2014)

Bill Bloking has 40 years' experience, and has held senior positions with BHP Billiton and Exxon. He is chairman of Nido Petroleum and MD of Gunson Resources. He was previously chairman of Norwest Energy and MD of Eureka.

Technical adviser: Paul Bilston, PhD

Paul Bilston has 15 years' experience in oil and gas. He has worked at Worley, GHD, AGL Energy and AJ Lucas. His recent focus has been on unconventionals in Australia and overseas, and he managed the Gloucester Gas project. He has a PhD in engineering.

Principal shareholders	(%)
LQ Super	12.6
Pitt Street Absolute Return Pty Ltd and related entities	5.0

Companies named in this report

Shell, Falcon Oil & Gas, Chevron, Sasol, PetroSA, Eskom

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