ANNUAL REPORT '15

FOR THE YEAR ENDED 30 JUNE 2015

LINC ENERGY

DIRECTORS

Mr Peter Bond
Executive Chairman
Mr Craig Ricato
CEO & Managing Director
Mr Ken Dark
Independent Non-Executive Director
Mr Mark Leahy
Independent Non-Executive Director
Mr James (Mun Foong) Yip
Independent Non-Executive Director
Mr Ong Tiong Soon
Non-Executive Director

COMPANY SECRETARY

Ms Janelle van de Velde

NOTICE OF ANNUAL GENERAL MEETING

The Annual General Meeting of Linc Energy Ltd will be held concurrently at:

BRISBANE

Boulevard Room
Boulevard Level
Brisbane Convention & Exhibition Centre
Cnr Merivale & Glenelg Streets
South Bank, Brisbane,
Australia

SINGAPORE

Grange Ballroom
Level 5, Main Tower
Mandarin Orchard Singapore
333 Orchard Road
Singapore

Date & Time
Thursday, 29 October 2015
1:00pm (Singapore time)
3.00pm (Brisbane time)

PRINCIPAL REGISTERED OFFICE IN AUSTRALIA

32 Edward Street
Brisbane, QLD 4000
Australia
Telephone: 61 7 3229 0800
Website: www.lincenergy.com

AUDITOR

KPMG

Level 16, 71 Eagle Street
Brisbane Qld 4000
Audit partner: Matthew McDonnell
Year appointed: 2008

BANKERS

Bank of Western Australia Ltd
National Australia Bank
Wells Fargo & Co
HSBC
KeyBank, N.A.

STOCK EXCHANGE LISTINGS

Linc Energy Ltd shares are listed on the Singapore Exchange (SGX: TI6) and in the United States of America on the OTCQX (OTCQX: LNCGY).

CORPORATE DIRECTORY

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CHAIRMAN'S MESSAGE

DEAR FELLOW SHAREHOLDERS,

THE 2015 FINANCIAL YEAR HAS UNDOUBTEDLY PRESENTED CHALLENGING CONDITIONS FOR THE ENERGY MARKET AND ESPECIALLY THE OIL AND GAS SECTOR AND ITS SHAREHOLDERS, PARTICULARLY WITH THE PRICE OF CRUDE OIL FALLING BY MORE THAN HALF, WHICH WAS A TRIGGER FOR THE DOWNWARD SLIDE OF THE SHARE PRICES OF MANY COMPANIES IN THE SECTOR. PERSONALLY I BELIEVE OIL PRICES WILL REBOUND BACK TO THE LEVELS WE HAVE BEEN EXPERIENCING OVER THE PAST SIX TO EIGHT YEARS, PRIMARILY BECAUSE RESOURCE DISCOVERY HAS BEEN LOWER YEAR ON YEAR AND THE REAL LEVEL OF OIL STOCKPILES, COUNTRY BY COUNTRY, IS STILL RELATIVELY LOW COMPARED TO OTHER COMMODITIES – AND YET WORLD CONSUMPTION OF OIL AND GAS CONTINUES TO RISE. IN MY EXPERIENCE THE MARKET DOES HAVE A TENDENCY TO FOCUS ON THE OIL SUPPLY AND DEMAND OF THE USA, BUT WHEN A GLOBAL VIEW IS TAKEN IT IS REASONABLE TO EXPECT THE GLOBAL OIL ECONOMY TO REBOUND QUITE STRONGLY.

The rapid decline in the oil price which occurred with few warning signs, needless to say put pressure on Linc Energy's margins, necessitated a heightened focus on realising operational efficiencies and on improving our overall financial position. The Company's new CEO and Managing Director, Craig Ricato and his team have put in place a number of cost saving and capital restructuring initiatives in the year under review, while also progressing opportunities to commercialise our projects and to better understand the assets we hold. Craig will provide more details about these programs in his report to you, but before he does so, I would like to briefly highlight the major events of the past year.

The Board was pleased with the results of the 2014/2015 Arckaringa Basin exploratory drilling program, particularly with the organics intersected in the Pata 1 well showing a high quality source rock with significant potential for oil generation at a high yield. There remains a considerable piece of work ahead in further ascertaining the potential and preparing a development plan to allow the Company to extract the maximum value from this resource. The Company recognises that this large oil and gas potential is not only good for the Company and our shareholders, but it's important for the increasing energy demand of the Asia region.

Underground Coal Gasification (UCG) collaborations are being pursued in other emerging jurisdictions such as China and Indonesia, while our previously announced project in South Africa has continued to be progressed, taking the Company closer to UCG commercialisation in this region.

In my last report to shareholders, I launched our new heavy oil business opportunity whereby Linc Energy's proprietary UCG technology is adapted for use in the recovery of heavy oil (which we've called 'Moving Injection Gravity Drainage' or MIGD) in an existing and well understood regulatory environment. Our preliminary work has provided encouraging results, indicating that MIGD is capable of operating at a much lower cost and higher output when compared to other heavy oil extraction methods. Initial studies have been very encouraging and we continue to explore opportunities in this area with a view to successfully demonstrating the commercial potential of this technology, which we believe would put the Company on the right track for Heavy Oil Recovery to become a significant revenue stream for Linc Energy.

While we continue to undertake the work necessary to commercialise our proprietary UCG technology, oil and gas production in the Gulf Coast and Wyoming has continued to be our 'bread and butter'. In light of the recent rapid decline in the crude oil price, this business line required operational efficiency to be maximised and our oil price hedging program to be strengthened. Despite the accounting impairments which many oil producers have had to book this year on the back of the declining oil price, the Company's Gulf Coast and Wyoming operations have proved and possible PV-10 reserves of USD$622.3 million[1]. Due to the efficiency initiatives implemented in the year under review, the Company can now produce oil at a significantly reduced cost per barrel, positioning us well for strong revenue growth on the back of improvements in the oil price.

The Company has continued to develop our oil and gas project at the Umiat field in Alaska, which has 2P Reserves of 155 million barrels of oil (MMBLS[2]). A detailed development concept is in place that includes near-term catalysts for unlocking value, along with details of feasible export options.

Our previously communicated strategy to simplify the business and divest non-core assets gained significant ground via the divestment of Linc Energy's coal subsidiary, New Emerald Coal Ltd, to the United Queensland Resources Pty Limited on 21 May 2015, following shareholder approval at an Extraordinary General Meeting. This sale eliminates a large annual expenditure for the Company, as well as provides access to royalties from future production. Linc Energy continues to progress opportunities to divest other non-core assets and we will provide more details about these commercially sensitive negotiations when we are able to do so.

Before I hand over to Craig, I should mention a number of changes at Board level, including:

- The Company's Board of Directors, including the CEO & Managing Director and I, agreed to reduce our salaries by 20%, effective from 1 July 2015 as a recognition of the challenging environment which the Company has to meet in the current financial year.
- The Nominating Committee and Remuneration Committee were amalgamated on 1 July 2015, resulting in cost and time savings.
- Three new highly experienced Directors were appointed to the Board, replacing Directors Jon Mathews, Lim Ah Doo and Koh Ban Heng who resigned due to various personal commitments. The Board thanks these Directors for their diligent service over the past years. To fill these positions we have been fortunate to appoint Director Ong Tiong Soon (TS) in June 2015, and Directors Mark Leahy and James (Mun Foong) Yip in August 2015. TS is the Chief Executive Officer of the Energy Division of Genting Berhad (Genting) and he has extensive, valuable and relevant experience that complements the skills of current Directors. Directors Mark Leahy and James Yip both bring a diverse range of skills to the Board, particularly from a financial perspective.
- All Corporate Governance policies were reviewed and updated, facilitated by Linc Energy's new Company Secretary, Janelle van de Velde, who was appointed to the role in January 2015.

Whilst the operating conditions of the past year have been arduous, it has forced the Company to drastically tighten its belt and optimise its processes in order to improve its financial position – all of which provide us with an ideal base from which to selectively grow a more focused conventional and unconventional oil & gas business. We are strategically positioned and equipped to capitalise on robust demand for oil and gas in the USA, Asia-Pacific, Africa and Europe and I am confident success in any of the major projects we have on the table will markedly improve the prosperity of this Company.

Thank you for your support over the past year and I look forward to a more promising 2016.

Yours sincerely,

Peter Bond
Executive Chairman

**Peter Bond was appointed Executive Chairman on 1 October 2014.*

** Notes:*

[1] Qualified Persons Reports by Haas Petroleum Engineering Services, Inc (Gulf Coast) and Ryder Scott Company, L.P. (Wyoming), both dated 30 June 2015.

[2] Qualified Persons Report by Ryder Scott Company, L.P. dated 11 December 2013.

CEO & MANAGING DIRECTOR'S REPORT

DEAR FELLOW SHAREHOLDERS,

I WOULD HAVE PREFERRED MY FIRST REPORT TO SHAREHOLDERS IN THE CAPACITY OF CEO & MANAGING DIRECTOR AT LINC ENERGY TO HAVE BEEN DURING A MORE PROSPEROUS TIME, BUT AS THE EXECUTIVE CHAIRMAN NOTED, THE PAST YEAR HAS PRESENTED CHALLENGING CONDITIONS THAT HAVE BEEN REFLECTED IN OUR FINANCIAL AND SHARE PRICE PERFORMANCE. DESPITE THE DIFFICULT ENVIRONMENT THE COMPANY'S STAFF AND MANAGEMENT HAVE REMAINED FOCUSED ON IMPROVING OUR FINANCIAL POSITION AND EQUITY VALUE; ON PRODUCING STRONG RESULTS IN OUR USA OIL & GAS OPERATIONS; CONTINUING PROGRESS TOWARDS THE COMMERCIALISATION OF OUR PROPRIETARY UCG TECHNOLOGY PLATFORM AND THE LONGER TERM DEVELOPMENT OF OUR RESOURCE POSITIONS IN BOTH ALASKA (UMIAT) AND THE ARCKARINGA BASIN IN SOUTH AUSTRALIA.

I am extremely pleased with the efforts of our people in responding to the changed operating environment and continuing to progress a number of our major projects, particularly given a significantly reduced headcount and greatly tightened budget. In the 2015 financial year overall costs for the Group were lowered by 41%, when compared to the prior financial year end.

The Company has retained a strong team of people capable of taking the Company past the current challenges and around which the business can grow in the future. We have a track record of successful monetisation, including the AUD$655 million sale of the Carmichael coal mine. While AUD$500 million of these proceeds was received upfront at the time of the sale in August 2010, in the year under review our team successfully negotiated two transactions relating to the remaining amount. Firstly, the future royalty stream was arranged to be paid out in advance at a value of AUD$155 million in two tranches, receiving benefit well in advance of first production and removing risks associated with delays. Secondly, delivery of the final tranche was expedited via the completion of a Receivable Factoring Agreement with a third party financial institution so as to accelerate the receipt of the proceeds and strengthen our balance sheet as we manage the current financial challenges.

Consistent with our strategy to divest non-core assets, Linc Energy was also able to complete the sale of its conventional coal subsidiary, New Emerald Coal Ltd, which delivers savings in excess of AUD$20 million per annum in administration and liabilities costs and enables the Company to potentially profit from future royalties with no outlay for mine development and production costs.

In the first half of the last financial year we commenced extended discussions with a number of parties in relation to the potential sale of all or part of our conventional oil assets in the Powder River Basin in Wyoming and in Umiat, Alaska. The dramatic downturn in the oil market has certainly impacted on these discussions and the Company's ability to transact in a manner that represents the fair value of these assets. We will continue to engage with interested parties as the opportunity arises and seek favourable deals as markets improve, but we will not allow events beyond our control to cause us to lose our focus on the continued prudent management and development of our shareholders' assets in the interim.

Linc Energy has engaged the Royal Bank of Canada (RBC) as its financial advisor to assist in the execution of strategic initiatives focused on reshaping the Company's capital structure. RBC is working closely with our corporate team as we are continuing to engage widely with potential investors and existing stakeholders to achieve our goal of ensuring that the Company moves forward with a sustainable capital structure right sized for our existing revenue base and capable of supporting our future growth.

As part of the program of debt restructuring, the Company received approval from Convertible Note holders for the Company to pay-down 25% of the Convertible Notes (USD$50 million) in January 2015, while the Redemption Put Date of the Notes was extended from April 2015 to April 2016 and 100% of our Second Lien noteholders in the USA agreed to capitalise our October 2015 interest payment. These two agreements have provided Linc Energy with the necessary time required to undertake a capital restructuring process in the current market. A number of other initiatives to strengthen liquidity and improve the Company's financial position are ongoing and I hope to provide more details about these activities in due course.

PRODUCTION

For the full year to 30 June 2015, revenue from the Company's conventional oil and gas assets in the United States was AUD$81.8 million (USD$68.5 million), which was lower when compared to the previous year primarily due to the deflated oil price.

During the year under review our operational team identified new development opportunities via the reprocessing of 3D seismic data on our Gulf Coast oil fields, which has resulted in a significant number of highly economic recompletion and new drilling prospects which the Company intends to develop over the coming two years to reach the higher production volumes on the back of improving oil prices in the future.

We were also able to bring our total cost per barrel of oil produced down to below USD$30 per barrel, including lease operating expenses, workovers, production taxes and general and administration expenses, with average June 2015 costs of USD$27.65/barrel. This low cost of production has been facilitated by a program of implementing efficiencies in the field, as well as a reduction in corporate US overheads during the year under review.

EXPLORATION

Linc Energy has a detailed development plan in place for our Umiat asset in Alaska, which has been independently estimated to contain one billion barrels of oil in place[1]. The team have progressed engineering studies, compliance with regulation and environmental studies, while also clearly defining export options and development plans.

In the coming year we intend implementing a low capital cost program specifically designed to advance our environmental impact study and plan of development, and progress the project towards full development approval.

The Company's drilling program in South Australia has certainly been successful in its main objective of improving our understanding of the Arckaringa Basin and moving this asset a step closer to the development stage. We were very pleased the new in-depth information gathered from this exploratory program indicated significant potential for hydrocarbon yields from selected formations in this Basin.

In the coming year, the Company will be completing the analysis of the data obtained during our FY2015 drilling program and reprocessing our seismic data to develop further exploration targets in the areas where we expect to encounter organically rich oil producing formations at greater depth and thermal maturity. Once this data set has been developed, we are committed to further exploration and development of this significant asset in a financially responsible manner.

TECHNOLOGY

We have shifted our focus in regards to our proprietary UCG technology from one of engineering and validation to near-term commercialisation and we are doing so by partnering with entities who have well defined resources, removing exploration risk for Linc Energy and, importantly, reducing the project development time. We have roadmaps in place for all of our potential UCG projects and at the time of writing this report we were in confidential negotiations with several potential joint venture partners, mostly in Asia.

** Notes:*

[1] Qualified Persons Report by Ryder Scott Company, L.P. dated 11 December 2013.

CEO & MANAGING DIRECTOR'S REPORT

Our commercial relationship with Exxaro Resources has continued with both parties working towards the goal of a commercial UCG project in Sub-Saharan Africa. Linc Energy has also progressed both engineering and exploration work to assist in confirming the commercial pathway for the proposed syngas hub on the Company's Cook Inlet site in Alaska.

A number of potential low cost, low risk opportunities in North America to deploy a pilot well program for our heavy oil recovery technology (MIGD) are also being evaluated. Results from the early stage technical and economic analysis of our MIGD process are encouraging, indicating that the technique will be capable of producing a higher quality of oil, at a lower cost of oil extraction, with less water and water treatment, as well as lower natural gas usage when compared to other heavy oil extraction methods.

SAFETY, ENVIRONMENT AND COMMUNITY

Wherever its activities are, Linc Energy strives to build positive, quality relationships with its stakeholders; to have all of our operations underpinned by professional environmental management, and to have a workplace with zero injuries and workplace related illness. I am pleased to report in the year under review:

- there have been no lost time injuries or work-related illness;
- Linc Energy has progressed environmental planning initiatives on a number of our major projects, including Umiat, Alaska; and
- the Company has consulted with landowners and local residents, councils and suppliers with the aim to balance business goals with the expectation of these stakeholders to create mutual and beneficial outcomes.

It would be remiss of me to not comment on the current court proceedings instigated by the Queensland Government's Department of Environment and Heritage Protection's (DEHP) and which the Company is continuing to vehemently defend. Despite being initially charged in April 2014, the full suite of evidence which the DEHP will seek to rely on before the court was not received by the Company until August 2015. Nonetheless, the Company's legal and expert team, at the time of writing this report, have already substantially prepared the Company's defence to the charges. In response to the media speculation the Company has received in recent months we have implemented a specific stakeholder engagement plan, particularly in relation to the DEHP's alleged detection of gases in soil samples taken in Chinchilla (Australia), in the broad region in which the Company's Chinchilla one square kilometre demonstration facility is located. The Department itself has conceded that there is no threat to public health, air quality, ground water, surface waters, soil or agricultural productivity. Linc Energy continues to defend the allegations and I remain confident that the final outcome of the court process will be a vindication of the Company and seriously questions the manner in which the DEHP has managed this process.

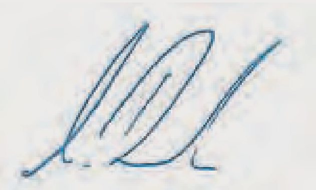
GOING FORWARD

The task ahead for Executives and the wider Linc Energy team in the short-term is not easy; there are a number of milestones that will need to be reached to achieve a more sustainable capital structure and better financial position, including the divestment of additional non-core businesses and the further reduction of cash burn, while also strongly increasing revenue.

I do believe our assets are world-class and I have confidence that the Linc Energy team is capable of meeting the current challenges, whilst continuing to optimise our oil and gas production, progress our long-term projects in South Australia and Alaska, and gain momentum necessary to realise the commercial opportunities generated by our proprietary technology platforms in UCG and heavy oil.

Thank you for your patience and continuing support.

Yours sincerely,



Craig Ricato

CEO & Managing Director

** Craig Ricato was appointed CEO and Managing Director on 1 October 2014.*

REVIEW OF OPERATIONS & ACTIVITIES

PRODUCTION

GULF COAST, TEXAS AND LOUISIANA

LINC ENERGY'S GULF COAST PROPERTIES COVER 15,521 NET ACRES ACROSS TEXAS AND LOUISIANA AND INCLUDE 150 PRODUCING WELLS OVER 11 ACTIVE FIELDS (OUT OF 14 TOTAL FIELDS), BOTH ONSHORE AND IN SHALLOW STATE WATERS. THESE FIELDS ARE CHARACTERISED BY SALT DOMES OR GEOLOGICAL STRUCTURES RELATED TO DEEP-SEATED SALT MOVEMENT THAT HAVE BEEN A SIGNIFICANT SOURCE OF OIL PRODUCTION SINCE THE TURN OF THE TWENTIETH CENTURY.

On 28 July 2015, Haas Petroleum Engineering Services, Inc. issued a reserve report effective 30 June 2015 estimating Proved (1P) reserves of 7.7 million barrels and 3.3 billion cubic feet of natural gas (equating to 8.3 mmboe) and prospective resource of 2.5 million barrels and 3.5 billion cubic feet of natural gas (equating to 3.1 mmboe). The PV10 of the Gulf Coast assets attributed to 1P Reserves is USD$193.9 million[1]. The decrease in value relative to the last Qualified Persons Report issued in December 2013 is primarily due to a decline in oil prices over the period, as well as a decrease in Proved Developed Non-Producing reserves.

For the financial year ended 30 June 2015, the average production of the Gulf Coast properties was 3,423 gross barrels of oil equivalent per day, while total cost per barrel of oil produced by Linc Energy, including lease operating expenses, workovers, production taxes and general and administration expenses, has decreased to below USD$30 per barrel.

Linc Energy's highly experienced Gulf Coast operational team analysed the significant amount of available 3D seismic coverage of the region to identify development opportunities, with the team currently adopting a moderated capital expenditure program focused on identifying highly economic recompletions and new wells selected and drilled based on risked net present value analysis.

GULF COAST STRATEGY

In the 2015 financial year, Linc Energy's Gulf Coast strategy has focused on optimising the Company's high-quality oil and gas assets in the region, on implementing cost efficiencies in the field and reducing oil and gas corporate overheads in the United States.

The Company continued to add to its Gulf Coast prospect inventory, with key Geologist and Geoscience experts reprocessing 3D seismic data to fully develop a suite of subsurface maps for core fields in order to locate new reserves with significant untapped potential. The team's efforts have led to the identification of more than 55 prospects, many of which are drill ready, with substantial potential additional upside available as only 25% of our High Island and 50% of Barbers Hill fields have been reviewed to date.

Corporate US Oil and Gas expenses were largely reduced and the majority of contractors were released, key talent and critical staff were retained to continue to drive forward Gulf Coast production. At the field level, operational efficiencies were found after completing a cost review for each field with a focus on a 60 day payout for workover and recompletion actions, as well as via the Company renegotiating fixed costs with vendors.

** Notes:*

[1] Qualified Persons Report by Haas Petroleum Engineering Services, Inc dated 30 June 2015.


Gulf Coast
LINC ENERGY EXPLORATION LICENSES & APPLICATIONS
HULL FIELD
PORT NECHES
HOUSTON OFFICE
Houston
BARBERS HILL
BLACK BAYOU
GOOSE CREEK
HIGH ISLAND
ATKINSON ISLAND, CEDAR POINT & UMBRELLA POINT
AQUARIUM
HOSKINS MOUND
GRASS ISLAND
Gulf of Mexico
0
20miles
40miles
Lease Area

ALL OF THESE COST SAVING INITIATIVES HAVE CONTRIBUTED TO A MUCH LOWER COST OPERATING ENVIRONMENT, WITH THE TOTAL COST PER BARREL OF OIL PRODUCED BY LINC ENERGY, INCLUDING LEASE OPERATING EXPENSES, WORKOVERS, PRODUCTION TAXES AND GENERAL AND ADMINISTRATION EXPENSES, BEING REDUCED TO BELOW USD$30 PER BARREL.

GOING FORWARD

Linc Energy intends to add to its prospect inventory in the Gulf Coast via the continued reprocessing of seismic data. The following prospects have already been identified and are expected to be developed by the Company where economically feasible through to the end of calendar year 2017.

The Company had already recommenced this new drilling program by August 2015, beginning with a new well in High Island. For the remainder of financial year 2016, Linc Energy has budgeted for one new well every two months, along with a number of recompletions, with new well prospects and recompletions averaging a payback period of 12 months and 2 months respectively.

FIELD	PROSPECT COUNT
Barbers Hill	18
High Island	18
Hoskins Mound	10
Port Neches	4
Galveston Bay	2
Black Bayou	3

POWDER RIVER BASIN, WYOMING

LINC ENERGY'S WYOMING CONVENTIONAL OIL ASSET IN THE POWDER RIVER BASIN SPANS 28,741 NET ACRES AND CONTAINS 31 PRODUCING WELLS ACROSS 3 FIELDS, NAMELY THE BIG MUDDY, SOUTH GLENROCK AND SOUTH COLE CREEK.

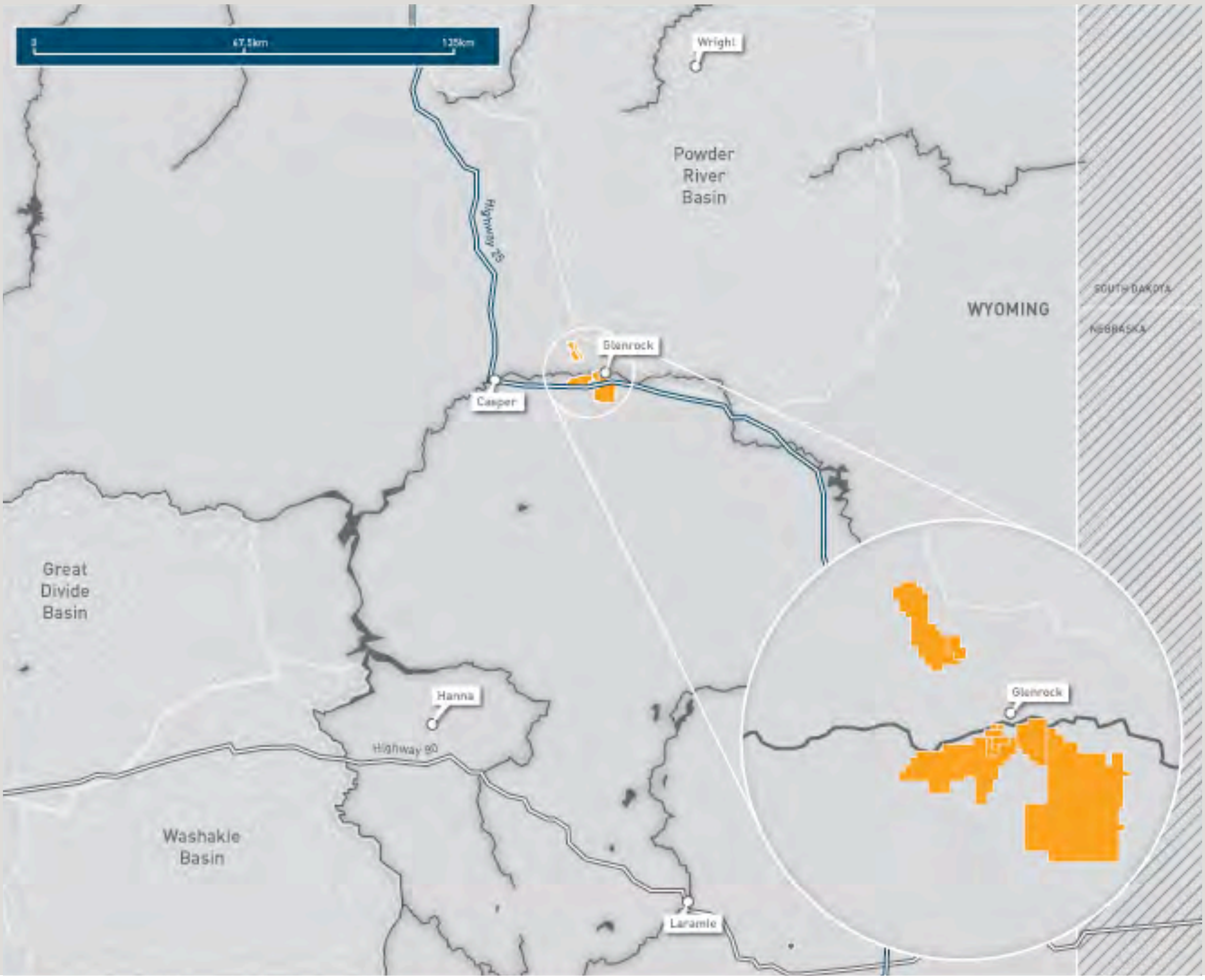
POWDER RIVER BASIN, WYOMING

On 30 July 2015, Ryder Scott Company, L.P. (Ryder Scott) issued a reserve report effective 30 June 2015 estimating Proved (1P) reserves of 551 thousand barrels of oil and possible reserves of 66.9 million barrels of oil (3P of 67.5 million barrels of oil). The PV10 of the Wyoming asset is USD$428.4 million comprised of Proved reserves of USD$5.6 million and Possible reserves of USD$422.8 million[1]. The decrease relative to the last Qualified Persons Report issued in December 2013 was primarily due to a decline in oil prices over the period.

Linc Energy is pursuing an Enhanced Oil Recovery strategy for the Wyoming assets, utilising tertiary recovery via carbon dioxide (CO_2) injection. CO_2 is considered one of the best mediums to use in this process as it acts as a solvent to sweep incremental oil to surface. To date the Company has completed reservoir modelling; a pre-feasibility study of CO_2 pipeline routes and an engineering study on the CO_2 recycle facility.

GOING FORWARD

Linc Energy has been contacted by parties interested in exploring possible joint ventures and for the purchase of the Company's Wyoming assets in their entirety. The Company continues to evaluate these possibilities and will provide more details to the market about these discussions should they progress further.



* Notes:

[1] *Qualified Persons Report by Ryder Scott Company, L.P. dated 30 June 2015.*

EXPLORATION

UMIAT, ALASKA

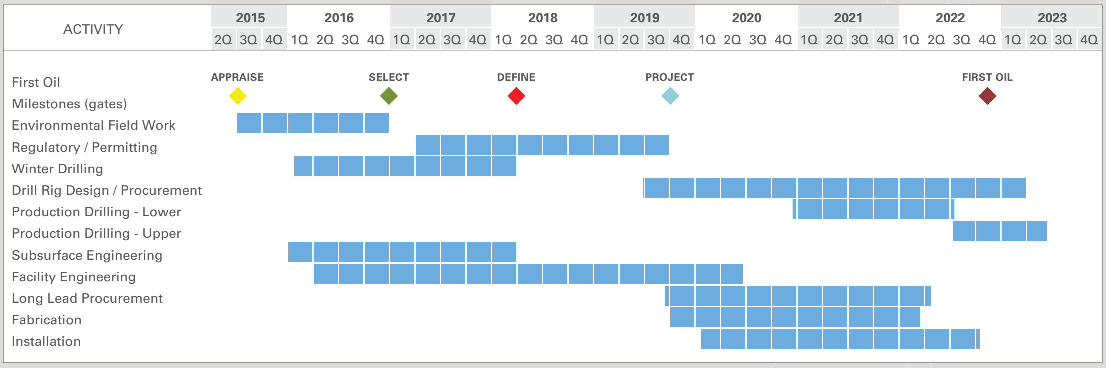
LINC ENERGY'S UMIAT FIELD COMPRISES LEASES COVERING 18,540 NET ACRES WITHIN THE NATIONAL PETROLEUM RESERVE OF ALASKA WHICH INDEPENDENT ANALYSTS RYDER SCOTT HAVE ESTIMATED TO CONTAIN ONE BILLION BARRELS OF OIL[1]. CONSIDERED TO BE ONE OF THE FEW REMAINING UNDEVELOPED LIGHT OIL RESERVOIRS IN NORTH AMERICA, THIS IS A STRONG ASSET LINC ENERGY IS ADVANCING THROUGH THE DEVELOPMENT STAGE.

Plans are in place for a high quality project with attractive economics and well-defined export options. The Company is targeting a peak production of 30,000 to 50,000 barrels per day, which reservoir modelling and flow testing at feasible rates has supported as an attainable output.

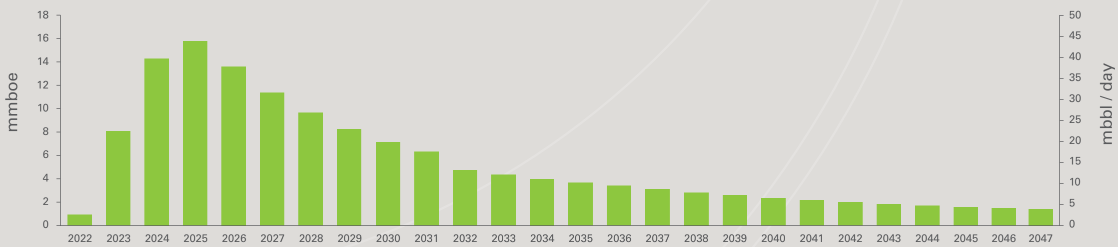
Linc Energy has previously successfully drilled and completed well number 23 in the Umiat field, which produced a light sweet crude oil at a peak rate of approximately 800 BPD providing excellent quality 38.5 API gravity oil, which is equivalent to a diesel class product flowing from the ground. The well design employed the latest in drilling and completion technologies delivering a 640 metre horizontal completion just 300 metres below surface. This successful outcome, combined with the knowledge gained from a former exploration season in Umiat, confirmed the quality and potential of this asset.

In the 2015 financial year, Linc Energy completed an engineering study to determine potential road and pipeline alignments and infield pad footprints, continued environmental studies, progressed regulatory compliance and prepared the property where possible at this stage in the process for future production.

UMIAT, ALASKA – DEVELOPMENT SCHEDULE

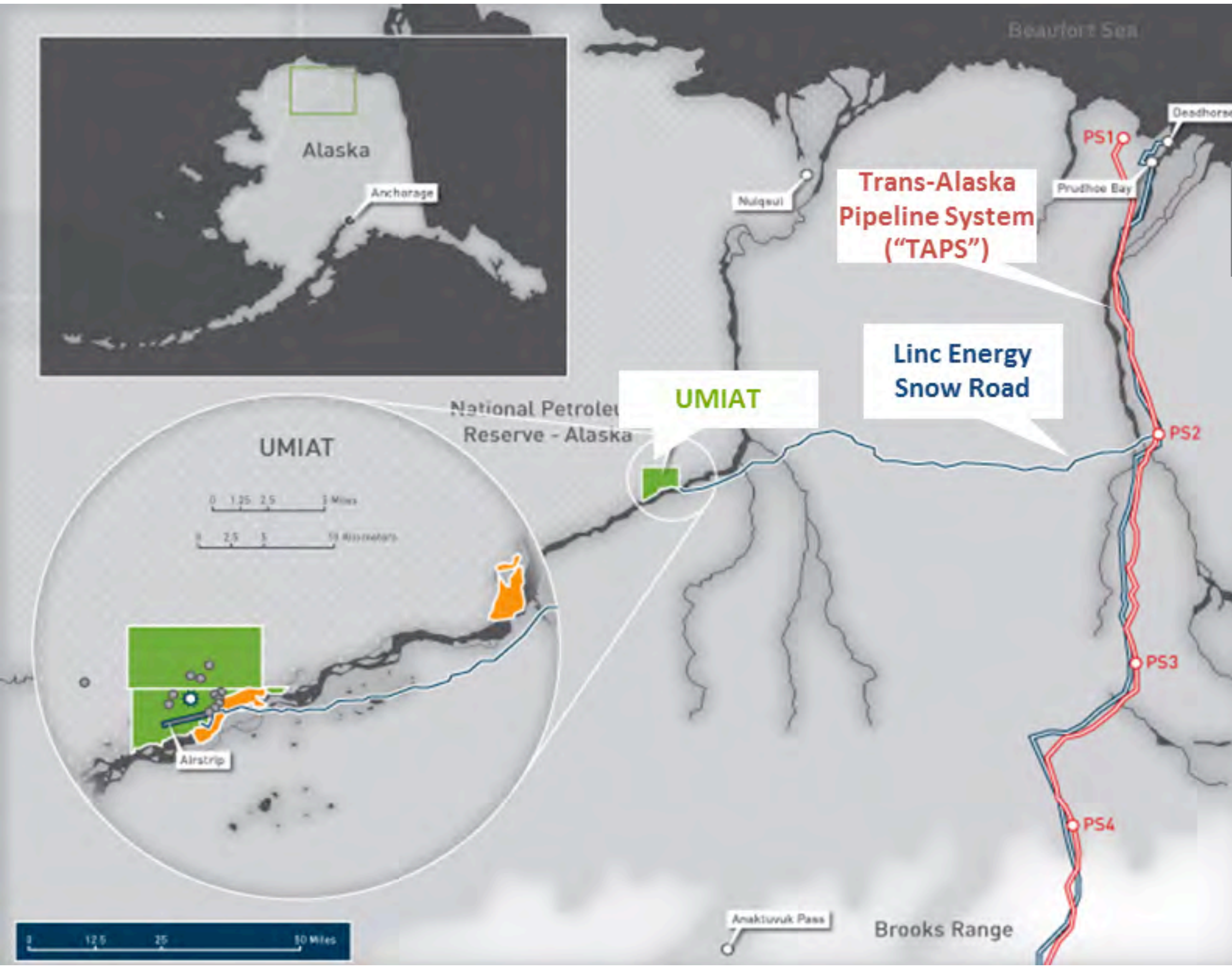


UMIAT, ALASKA – TARGET PRODUCTION



** Notes:*

[1] Qualified Persons Report by Ryder Scott Company, L.P. dated 11 December 2013.



ALASKA ASSET LOCATION

PROJECT PLAN OVERVIEW

The development plan model chosen by Linc Energy includes five infield pads with approximately 35 wells laid out in an 80 acre drainage pattern, targeting the Lower Grandstand formation. The Upper Grandstand formation will be targeted using the existing pads and a similar well pattern. Well spacing is projected to be 900 feet with an approximate 5,000 feet lateral length achievable due to the shallow depth of the reservoir.

The planned project will leverage existing export infrastructure with low risk tie-in to the Trans-Alaska Pipeline System (TAPS). Twelve potential routes were initially identified as part of the access route selection process, which was reduced to six potential routes based on technical and permitting constraints. Further consideration of the maximum allowable road grade, proximity to environmentally sensitive areas, and nearness to the Toolik Research Station, resulted in the potential export routes being reduced to three options, however there is also the ability to build a road or maintain a pipeline through remote access.

Linc Energy is currently working through the detailed development plan for this project, which timetables additional environmental field work, further application preparation and permitting, subsurface and facility engineering, procurement, facility fabrication and installation, before reaching the peak production objective.

GOING FORWARD

In September 2014, Linc Energy announced it had received unsolicited expressions of interest for its Umiat conventional oil asset. The Company continued discussions with these and other potential farm-in partners to jointly develop this asset and until such time as a favourable outcome for Linc Energy can be reached, the development plans will continue to be progressed by the Company's highly experienced team.

There are several upcoming milestones that will build on work already completed to drive value going forward in the Umiat project. Completion of resource modelling, the Environmental Impact Statement and permitting process will all add to the project value. The Umiat team will also be analysing potential upside from deeper oil and gas reserves which have been identified through reprocessing of 3D seismic data. Longer-term, roads and pipelines are to be built, process facilities constructed, development drilling commenced and construction of TAPS facilities and connection.

ARCKARINGA BASIN, SOUTH AUSTRALIA

LINC ENERGY HOLDS SEVEN EXPLORATION LICENCES AND TWO LICENCE APPLICATIONS IN THEIR ENTIRETY FOR THE ARCKARINGA BASIN IN SOUTH AUSTRALIA, COVERING 16 MILLION CONTIGUOUS ACRES, OR 80% OF THE BASIN, WITH EXPLORATION RIGHTS EXCEEDING EIGHT YEARS OVER PROSPECTIVE AREAS.

Independent consultants DeGolyer and MacNaughton have estimated a potentially enormous unrisked prospective unconventional resource of 103 and 233 BBOE respectively[1,2] in the Arckaringa Basin and a previous exploratory drilling program by Linc Energy in 2010 discovered a light, sweet crude oil, providing proof of an active petroleum system in this Basin.

In late 2014 Linc Energy commenced the next phase exploratory drilling program in the Arckaringa Basin in order to improve the Company's understanding of this asset. Three of the geological formations that both Gustavson Associates and DeGolyer and MacNaughton had identified as prospective resources were targeted in the program with the results showing both formations had significant hydrocarbon generation potential.

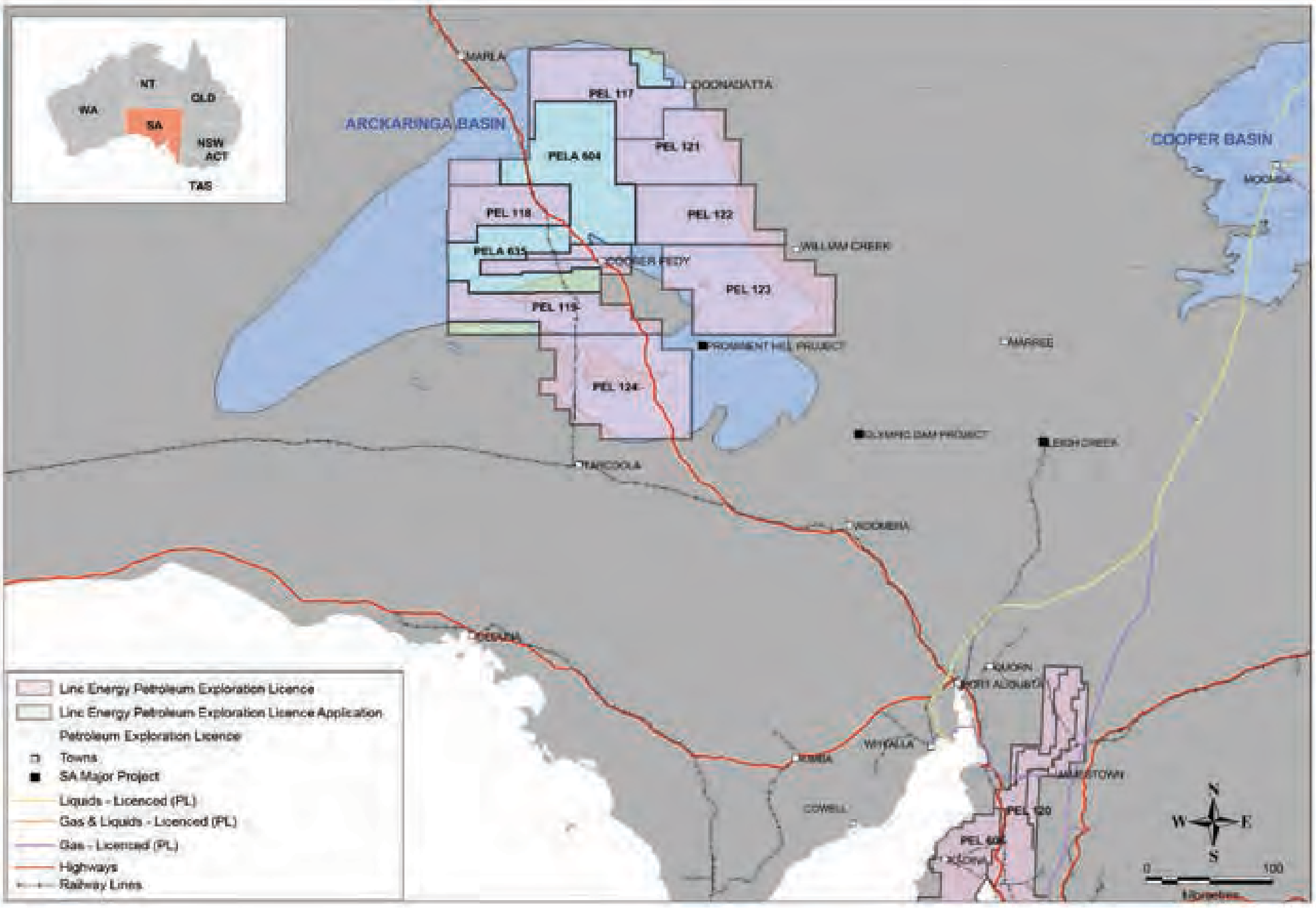
The Stuart Range Formation indicated potential yields of up to 54 litres of oil per tonne, while the organic intervals within the Boorthanna Formation indicated a possible output of up to 70 litres of oil per tonne. Additionally, organic rich mudstones and coals were intersected within the Boorthanna Formation, signifying the discovery of an additional, previously unknown source rock.

Data gathered throughout this drilling program and to date about the Arckaringa Basin will be used to inform a development plan focused on extracting as much value from this resource as possible.

** Notes:*

[1] The Prospective Resources estimate in the DeGolyer and MacNaughton report dated 21 January 2013 was prepared in accordance with the Petroleum Resources Management System (PRMS) approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers by John W. Wallace (consultant).

[2] Prospective Resources are those quantities that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Application of any geological or economic chance factor does not equate prospective resources to contingent resources or reserves.



ABOUT THE 2014/15 EXPLORATORY DRILLING PROGRAM

The 2014/2015 Arckaringa Basin exploratory drilling program was designed to assess the potential of the Arckaringa Basin for unconventional hydrocarbon production and consisted of drilling two wells, namely Pata 1 and Eba 1 located in Petroleum Exploration License (PEL) 121.

Each well was completed in two sections with the initial pre-collar drilled and cased off prior to a larger rig continuing to depth and completion. This method of drilling the wells in two sections is cost effective and also considered best practice as it ensures the integrity of the region's sub-surface water systems. Cuttings and core recovered during drilling were sent to Houston and Brisbane for analysis and included geochemical testing to confirm thermal gradient projections and source rock quality, along with geo-mechanical evaluation of the rock strength and porosity and permeability evaluation to determine reservoir characterisation.

Drilling at Pata 1 intersected organic rich shales within the Stuart Range and Boorthanna Formations which exhibited excellent potential for hydrocarbon generation. A number of coal seams were also intersected within the Boorthanna Formation and may constitute an unknown hydrocarbon system within the Basin and a significant opportunity for the Company. While the organic intervals within the Boorthanna Formation at Pata 1 are comparatively thin, a number of additional targets have been identified in the southern portion of the Boorthanna Trough within PEL123 which are anticipated to have similar source characteristics. Linc Energy will continue to review seismic data to define areas where the Stuart Range and Boorthanna Formation are at greater depths and exposed to higher heat flow. Additional seismic will be required as previous programs have traditionally focused on delineating stratigraphic highs and conventional targets within the Basin rather than the troughs.

Drilling at the Eba 1 well targeted a thick package of pre-Permian sediments interpreted to be up to two kilometres thick and believed to be the source of the Maglia 1 oil show (Linc Energy's previous exploratory drilling program in the Arckaringa Basin). In this well, the intersected pre-Permian sediments contained lower Total Organic Carbon content than was expected however initial interpretation has indicated they were mature enough to have produced hydrocarbons in the past. The pre-Permian Formations are being remapped within the regional seismic model to better understand the organic areas that could constitute potential source rocks for hydrocarbon generation.

2014/2015 ARCKARINGA BASIN EXPLORATORY DRILLING PROGRAM RESULTS

MEASUREMENT	PATA 1		EBA 1		COMMENTS
Total Depth	1828m		2959m		Pata 1 intersected the thickest section of Permian sediments ever drilled in the Arckaringa Basin. Eba 1 is the deepest well ever drilled in the Arckaringa.
Sample Type	Rotary Side Wall Core 2 Cuttings		Cuttings only		
Formation Target	Stuart Range Formation	Boorthanna Formation	Boorthanna Formation	Pre-Permian Formation*	
Total Organic Carbon (TOC)	Average 8.26% Maximum 11.6%	Average 6.15% Maximum 10.1%	Average 3.13% Maximum 4.03%	Average 0.63% Maximum 2.82%	A TOC greater than 2% is considered excellent when describing source rock generative potential.
Hydrogen Indices (HI)	Average 288 Maximum 540	Average 344 Maximum 594	Average 160 Maximum 199	Average 4 Maximum 37	Prospective Source Rocks with a HI greater than 300 prone to oil generation. A HI of 150 – 300 are considered Oil & Gas Prone.
Kerogen	Predominantly (>80%) type 1 and 2 Kerogens	Predominantly (>80%) type 1 and 2 Kerogens	n/a	n/a	Type 1 and 2 Kerogens are prone to oil generation.
Vitrinite Reflectance (Ro)	0.6 to 0.62	0.66	n/a	n/a	Within oil 'window' of 0.6 – 1.4% Peak oil generation occurs at approximately 0.65% – 1.00%.
TMAX (Celsius)	433 - 438	428 - 430	428 – 437	313 – 399	Oil window of 430 – 460
Production Indices (PI)	Average 0.03 Maximum 0.04	Average 0.06 Maximum 0.08	Average 0.025 Maximum 0.03	Average 0.36 Maximum 0.43	The PI is indicative of the conversion of kerogen into free hydrocarbons A PI of 0.08 – 0.5 is considered within the oil window.
Oil Saturation Index (mg HC / g) (S1 / TOC)	7 - 24	15 - 28	4	1 – 19	In order for a prospective Shale Resource to be classified as a Reservoir, the Oil Saturation Index must exceed 100mg HC / g.
Potential Yields (S2)	Up to 54 litres of oil / tonne (47.98mgHC/g rock)	Up to 70 litres of oil / tonne (62.9mgHC/g rock)	Up to 9.02 litres of oil / tonne (8.02mgHC/g rock)	Low	A rock with a S2 greater than 10 mgHC / g is considered to have very good source rock generation potential.
Porosity	13.1%	n/a	n/a	n/a	Porosity is consistent with other producing oil fields such as the Eagleford and Bakken Shales.
Permeability	13.7nD	n/a	n/a	n/a	Permeability of the Pata 1 samples is considered low. Untested sandy bands within the Stuart Range. Formation are expected to exhibit higher permeability measurements similar to that seen in other wells within basin.

** The Eba 1 results indicated the Formation has previously produced and the remaining organic content is inert.*

All Rotary Side Wall Core and cuttings analysis was completed by the accredited Weatherford Laboratories (http://www.weatherfordlabs.com). Due to the large file size of the supporting documentation, copies of the accreditations and analytical methods can be viewed upon request at Linc Energy's registered office. Weatherford is paid a service fee based on its standard professional fee structure, the payment of the fee is not contingent on the outcomes of the analysis.

GOING FORWARD

The 2014/15 Arckaringa Basin drilling program has been successful in its main objective of improving Linc Energy's understanding of the Basin's potential, while also moving the Company another step closer to defining a commercial resource. Based on the program's results, Linc Energy has confidence the Arckaringa Basin contains significant hydrocarbon potential and is committed to developing this asset in a cost effective manner so as to ensure shareholder value is maximised.

Existing seismic data will be reprocessed and combined with newly acquired seismic information to assist in identifying the next drilling targets. While these initial investigations can be completed in a cost effective manner, the Company recognises the need to attract strong strategic partners and is focused on delivering a transaction that supports an accelerated exploration and development program.

There are many infrastructure advantages to developing this project in the Arckaringa Basin, including an extremely flat terrain with minimal surface restrictions, abundant access to shallow aquifers, as well as a nearby heavy gauge railway with access to major export hubs. These positive aspects combined with the rare size and quality of the resource in the Arckaringa Basin, provides Linc Energy with a unique opportunity which would not only be attractive to potential partners, but also of interest to emerging countries whose demand for oil and gas is anticipated to grow in the coming years.

TECHNOLOGY

UNDERGROUND COAL GASIFICATION

LINC ENERGY OPERATES THE WORLD'S LONGEST RUNNING COMMERCIAL UNDERGROUND COAL GASIFICATION (UCG) FACILITY IN UZBEKISTAN AND HAS A LICENSE FEE ARRANGEMENT WITH EXXARO RESOURCES TO DEVELOP UCG IN SUB-SAHARAN AFRICA. ADDITIONALLY, STRATEGIC RELATIONSHIPS HAVE BEEN DEVELOPING IN EMERGING JURISDICTIONS SUCH AS INDONESIA AND CHINA TO CREATE REVENUE GENERATING UCG OPERATIONS.

As UCG syngas can be used as a feedstock for power and liquid transport fuel production, the Company's proprietary UCG technology remains attractive to countries that would benefit from having independent energy and fuel sources, particularly those that also have abundant sources of stranded coal resources which would be uneconomical to extract via traditional mining methods, but are suitable for UCG.

Linc Energy has completed detailed strategic plans for all potential projects in the countries of interest and the Company is focusing on developing UCG operations in conjunction with partners who bring well-defined, known resources to the table. These resources can be quickly assessed by Linc Energy's technical teams, removing exploration risk and reducing the time required for future commercial project development.

ASIA-PACIFIC

Linc Energy is in confidential negotiations with several potential joint venture partners in Asia to develop UCG in the region. Following are the key developments in major projects that have taken place in the 2015 financial year.

AUSTRALIA

The decommissioning of Linc Energy's UCG demonstration facility on the Company-owned property in Chinchilla has continued in a cost effective manner. Two of the five gasifiers at this location are still undergoing the venting and flushing stages which are necessary prior to final decommissioning. It is expected these stages will be completed by the end of calendar year 2015, at which time the focus will shift to finalising the site decommissioning study, answering remaining questions posed by the Independent Scientific Panel and commencing the final land rehabilitation.

Linc Energy continues to defend the allegations made by the Queensland Government's Department of Environment and Heritage Protection in relation to the detection of gasses in soil samples taken in the wider Chinchilla area. The Department has conceded there is no threat to public health, air quality, ground water, surface waters, soil or agricultural productivity. The Company remains committed to defending itself in the proper forum before the courts in regards to this matter, with the committal hearing scheduled to commence in October 2015 and continue into November 2015.

UCG'S POTENTIAL – ASIAN STRANDED COAL DEPOSITS

LINC ENERGY IS CONTINUING TO EXPLORE OPPORTUNITIES ACROSS A NUMBER OF COUNTRIES AND TERRITORIES WITHIN THE EUROPEAN AND AFRICAN MARKETS. FOLLOWING ARE THE MAJOR PROJECTS IN THESE REGIONS.

EUROPE AND AFRICA

SOUTH AFRICA

The Company has been developing a project plan to provide UCG solutions for Sub-Saharan Africa with commercial partner Exxaro Resources, one of South Africa's largest diversified coal resource groups. Linc Energy is scheduled to receive a payment of AUD$7 million subject to a performance test once the facility is operational, to supplement funds of AUD$23 million in licence fees received to date. Linc Energy also has a minimum 15% equity position in the initial UCG project and the Company will be eligible for royalties (linked to an energy index) for the synthesis gas produced and sold.

POLAND

Due to economic conditions in the market and the suppressed price for oil and natural gas, the development of the Polish UCG project has been placed on hold. The project will be re-evaluated when the market conditions improve and a more sustainable long–term outlook can be concluded. The Company will redeploy resources into other more viable projects within Africa and Asia.

TANZANIA

The relationship with Olympic Exploration will not be progressing and the associated MOU agreement has now expired. Linc Energy continues to explore opportunities with Tanzania both directly and via strategic partnerships.

UZBEKISTAN

Linc Energy owns the world's longest running commercial UCG operation. Known as Yerostigaz and located in Angren, Uzbekistan, the facility has consistently produced one million cubic metres of UCG syngas per day since 1961. UCG syngas produced at the facility is used for electricity generation at the nearby Angren Power Station. Linc Energy has identified enough coal in its nearby tenements to maintain production by Yerostigaz for the next 50 years.

THE AMERICAS

ALASKA

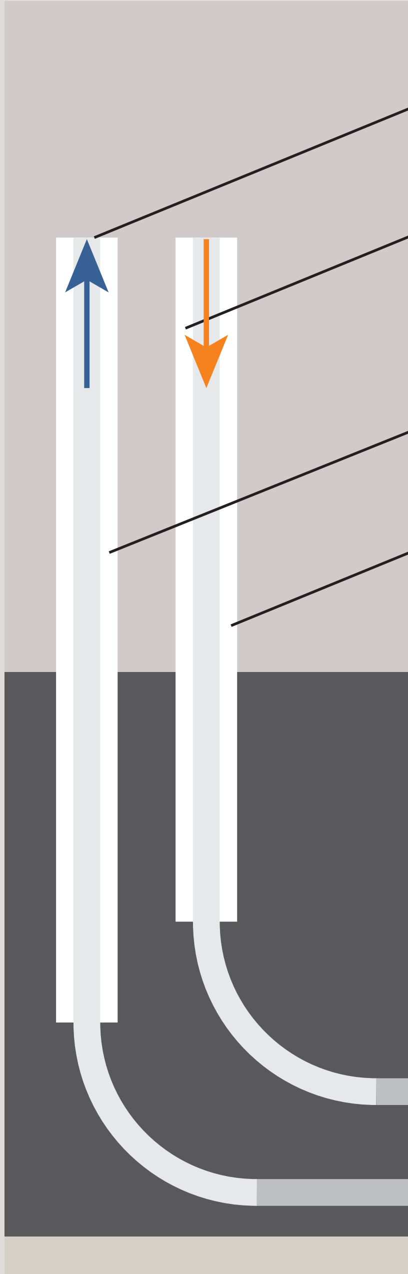
The Company's Alaskan UCG project has been paused with the intention to reconsider this endeavour when market conditions recover and a more sustainable long-term outlook can be determined, in the meantime allowing the Company to redeploy resources into other more currently feasible projects.

WYOMING

In September 2014, Linc Energy was granted a UCG Research and Development License by regulators in Wyoming, USA. This is a significant milestone for the Company as this is the first UCG project approved in the United States in 20 years. Linc Energy's UCG R&D License meets all of the stringent technical and regulatory requirements imposed by the Federal Environmental Protection Agency, as well as the Wyoming Department of Environmental Quality. The Company is currently evaluating the commercial investment and development options for this jurisdiction.

HEAVY OIL RECOVERY

LINC ENERGY HAS COMMENCED THE PROCESS TO PATENT AN APPLICATION OF ITS UNDERGROUND COAL GASIFICATION TECHNOLOGY FOR THE EXTRACTION OF HEAVY CRUDE OIL WHICH SUGGESTS IMPROVED COST AND EFFICIENCY PERFORMANCE WHEN COMPARED TO TRADITIONAL EXTRACTION METHODS. THE COMPANY'S INNOVATION USES A CONCEPT CALLED MOVING INJECTION GRAVITY DRAINAGE (MIGD), WHICH TAKES PLACE IN-SITU (UNDERGROUND) AND INVOLVES THE HEAVY OIL BEING GRAVITY DRAINED POST COMBUSTION AND AIR INJECTION.



There are plentiful resources of heavy oils and oil sands bitumen in the world, with large resources present in Canada, South America, Russia and the Middle East. To extract these resources they must be heated so that the oil will flow easily to production wells. Commonly, steam is generated at surface and injected into the reservoir to heat up oil and make it flow. Steam generation requires large quantities of water and natural gas.

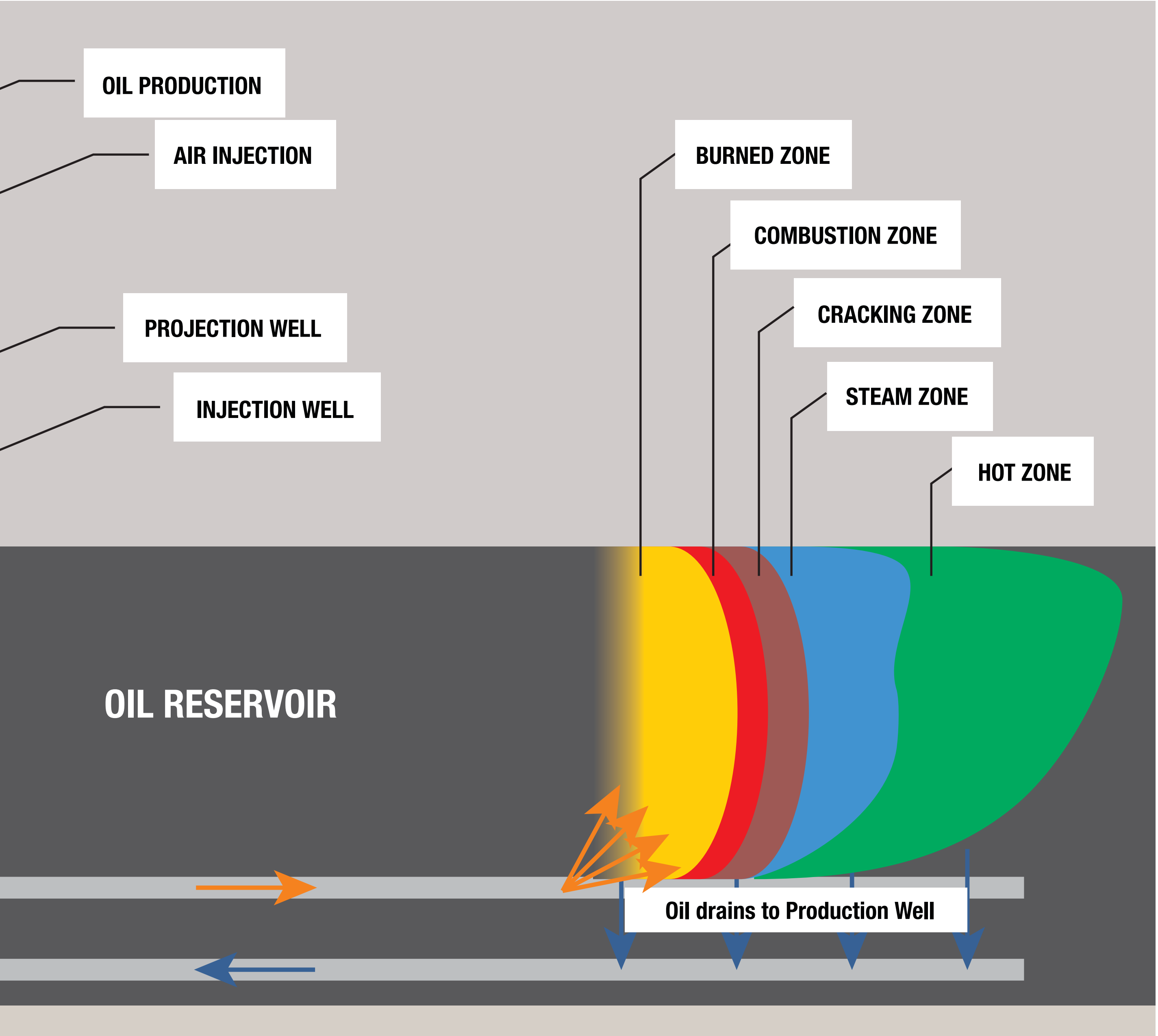
Linc Energy's MIGD process applies a combustion process derived from underground coal gasification which heats up the oil in situ. Compared to conventional extraction methods including Cyclic Steam Stimulation and Steam Assisted Gravity Drainage the MIGD process produces a higher quality of oil, uses less water and much less natural gas. As shown in the schematic, air is injected into the top well, where it combusts and heats up the oil, enabling an upgraded lighter oil to flow via gravity to the production well located at the bottom of the reservoir. The key differentiators of this innovation are how the combustion process is controlled and this is where Linc Energy's experience from underground coal gasification is utilised.

Engineering studies and reservoir simulations show that the process can produce commercial quantities of oil and that capital costs are competitive with steam based methods, while operating costs are significantly lower. The MIGD process is also expected to be effective in reservoirs where steam technology is not suited, such as fractured, low permeability shale and heterogeneous reservoirs.

KEY DIFFERENTIATORS OF INVENTION

FUNCTIONAL REQUIREMENT	ACHIEVED BY
Control rate of oxidant injection	Inject oxidant to maintain minimum air flux for effective combustion
Control location of oxidant injection	Move oxidant location through the formation (sweeping)
Produce oil via gravity drainage	Locate production well below injection well

MOVING INJECTION GRAVITY DRAINAGE



GOING FORWARD

The Company has been completing development design in regards to its MIGD heavy oil recovery and has conducted initial studies which have been encouraging and support the benefits associated with this process. Discussions with potential partners have taken place and the Company continues to explore additional low cost pilot well deployment opportunities.

CORPORATE

NEW EMERALD COAL LTD

Linc Energy completed the sale of its conventional coal business, including 100% of the shares in its subsidiary New Emerald Coal Ltd, to United Queensland Resources Pty Limited (a part of the United Mining Group) on 21 May 2015. The sale was announced by the Company on 16 February 2015, with shareholder approval granted for the transaction at an Extraordinary General Meeting held on 14 May 2015.

A combination of sale proceeds and access to future royalty streams was chosen as this type of model has worked well for the Company in the past and allows for benefit from development of assets as the coal market improves over coming years.

Linc Energy will have access to the following future royalties from three potential mines (Blair Athol coal mine – subject to the completion of this acquisition by New Emerald Coal Ltd; Teresa coal mine; and Pentland coal mine) with a combined JORC code compliant Resource of 614.1Mt (12.6Mt Measured, 266.5Mt Indicated, 335Mt Inferred[1,2]):

- an indexed USD$1.00 per product tonne on coal from the Teresa and Pentland projects; and
- an indexed USD$0.50 per product tonne on coal from the Blair Athol mine.

Importantly, United Queensland Resources Pty Limited is responsible for all future development costs and liabilities, creating savings for Linc Energy in excess of AUD$20 million per annum in administration and existing liabilities cost alone.

CAPITAL IMPROVEMENTS

A restructure of the Group's borrowings has been significantly progressed via a number of initiatives and the Royal Bank of Canada (RBC) has been selected to act as financial advisor in the execution of capital programs to strengthen the Company's financial position.

In December 2014, as part of the program of debt restructuring, the Company received support from Convertible Note holders for the Company to pay-down 25% of the Convertible Notes (USD$50 million) in January 2015, while the Redemption Put Date of the Notes was extended from April 2015 to April 2016. Separately, the Company obtained 100% approval from the Second Lien noteholders in the USA to have the option to capitalise our October 2015 and April 2016 interest payments. These two agreements have provided Linc Energy with the necessary time required to undertake a capital restructuring process in the current market. A number of other initiatives to strengthen liquidity and improve the Company's financial position are ongoing and we will provide more details about these activities as appropriate as they progress.

CARMICHAEL ROYALTY (ADANI)

On 28 August 2014, Linc Energy was pleased to announce it had entered into a binding Option Deed for the transfer of Linc Energy's benefits in and obligations under the Carmichael Royalty Deed to Adani Group (Adani). The Option exercise consideration under the Option Deed was AUD$155 million.

The first tranche of AUD$90 million was received from Adani in October 2014 with the balance due on or before 9 October 2015. The Company secured an opportunity to receive the second tranche early in April 2015, via a Receivable Factoring Facility Agreement with a third party financial institution.

These transactions boosted Group liquidity at a time when other industry players were struggling due to low commodity prices.

** Notes:*

[1] Coal Resources have been estimated and reported (in compliance with the JORC Code, 2012 Edition) by Xenith Consulting Pty Ltd ("Xenith"). The Competent Person is Mr Troy Turner, a full time employee of Xenith. Mr Turner has given his consent to the inclusion of information in this report on matters related to Coal Resources in the form and context in which it appears.

[2] Coal Resources have been estimated and reported (in compliance with the JORC Code, 2004 Edition) by Xenith. The Competent Person is Mr Troy Turner, a full time employee of Xenith. Mr Turner has given his consent to the inclusion of information in this report on matters related to Coal Resources in the form and context in which it appears.

THE BOARD 2015

1) Peter Bond [1]

EXECUTIVE CHAIRMAN

Peter Bond has a successful track record in the coal and mining industries, both in Australia and overseas. His business interests include mineral, mining and associated operations in Australia and South East Asia.

Peter was appointed to the Linc Energy Board in October 2004 and has been pivotal to its success since it listed on the Australian Securities Exchange in May 2006. He has personally seen the Company evolve to a global company with offices and projects throughout the Asia-Pacific, Europe, Africa and the Americas.

Building on his early engineering background, Peter has gained a unique knowledge and understanding of the coal industry over the course of a diversified career spanning more than 20 years. Peter has experience in the design, installation, commissioning and operation of complex processing plants and projects, and his various companies are recognised in the mineral processing industry for both innovation and efficiency.

2) Craig Ricato [1]

CEO & MANAGING DIRECTOR

Craig Ricato was appointed as the CEO & Managing Director in October 2014. He brings a broad range of international experience to the Board across the regulatory, accounting and legal industries, together with a detailed understanding of Linc Energy's operations and assets developed over the previous seven years, to this role.

Craig was Linc Energy's Director, Legal and Corporate Affairs for over five years before resigning in June 2013 to pursue other opportunities outside of the Company. He continued to act as a Non-Executive Director of Linc Energy until the appointment to his current role.

Craig obtained a Bachelor of Commerce degree in 1991 and was admitted as a Legal Practitioner of the Supreme Court of NSW and Queensland in 2001 after graduating with a Bachelor of Laws with First Class Honours. Craig has extensive experience working on legal and corporate matters related to the energy and resources industry, specifically with respect to cross-border transactions, international business structuring, mergers & acquisitions and equity capital markets. His early career background prior to joining the legal profession was in forensic accounting and law enforcement.

3) Ken Dark [1]

INDEPENDENT NON-EXECUTIVE DIRECTOR

Ken Dark was appointed to the Linc Energy Board in October 2004 and was Chairman from 2011 to 2014. He began his early working life as an electrician before gaining tertiary engineering qualifications and ultimately managing an in-plant multi-disciplined project engineering team at Alcan's Australian Smelter. At that time, projects included world-leading innovations in Industrial Process Control. Concepts Ken pioneered are still the mainstay of process control for the international aluminium smelting industry.

In 1986, Ken left the corporate world and established a successful business in the fuel distribution and retail industry. He has represented fuel distributors and retailers, chairing the national marketing committees for two major fuel companies and leading the national franchise negotiation committee to the successful renewal of contracts with one of the oil majors. He is a founder and silent partner in a small chain of independent fuel and grocery outlets. Ken has also had experience in freelance management consulting and is a Graduate member of the Australian Institute of Company Directors.

** Notes:*

[1] On 1 October 2014, Peter Bond became Executive Chairman of the Board of Linc Energy and fellow Board member, Craig Ricato, was appointed to the position of CEO & Managing Director. As at this date, Ken Dark, who was previously Chairman, remained on the Linc Energy Board in the capacity of Non-Executive Director.

4) Ong Tiong Soon [2]

NON-EXECUTIVE DIRECTOR

T.S. Ong (full name: Ong Tiong Soon) is a Singaporean, age 71. He is the Chief Executive Officer of the Energy Division of Genting Berhad ("Genting"). He started his working life with the Port of Singapore Authority, where he worked for 11 years. Prior to joining the Genting Group, T.S. ran the Smorgan Sanyen Paper Mill in Singapore which he co-owned with the Smorgan family of Australia.

During his tenure with the Genting Group, T.S. led the development and operation of a number of substantial projects in the manufacturing, power generation and oil & gas sectors. His first project with the Genting Group was to construct the Genting Sanyen Industrial Papermill in 1992 which then evolved into the largest paper and packaging complex in Malaysia. This business was sold to CVC when the Genting Group decided to focus on the energy sector, comprising power generation and oil & gas exploration and production.

In the power sector, T.S. developed and managed (through greenfield construction or acquisition) a portfolio of 7 power plants in 3 countries with total generation of about 4,600MW. The plants include the 720MW gas-fired Kuala Langat Power Plant (the first Independent Power Producer in Malaysia to sell electricity into the Malaysian power grid), a 724MW coal-fired power plant in China, and a 92MW wind farm in India.

Under the charge of T.S., the Genting Group is currently building a 680MW coal-fired power plant in Jawa, Indonesia and a 2,000MW coal-fired power plant in China with the State Development and Investment Corp of China as joint venture partner.

In oil & gas exploration and production, the Genting Group is focused in two familiar countries – Indonesia and China. Its first project was a joint venture with British Gas in the Muturi Block, West Papua, Indonesia. After gas was discovered in Muturi, the Genting Group sold its interest to BP. Today, the Muturi Block along with other gas fields supply gas to the Tangguh LNG Project. Next came the discovery of oil in two offshore blocks, Northwest Natuna and Anambas in the Natuna Sea, Indonesia. TS's main focus in Indonesia is the on-shore Kasuri Block in Irian Jaya, Indonesia, where very substantial gas reserves have been discovered during exploration. The Genting Group is working to progress to the development phase of the block.

In China, the Genting Group very successfully operated the Zhuangxhi Buried Hill Enhanced Oil Recovery oil field in north eastern China for 12 years until its equity interests in the project were sold in 2010. At present, the Genting Group owns a 57% interest in the Chengdaoxi Offshore Production Block in the north east of China. This joint venture with Sinopec produces more than 8,000 barrels of crude oil per day.

[2] Ong Tiong Soon was appointed to the Board of Linc Energy on 28 May 2015.

** Former Directors not pictured are Jon Mathews, who retired from the Board of Linc Energy on 31 July 2015 and Directors Koh Ban Heng and Lim Ah Doo who resigned on 25 May 2015 and 24 June 2015 respectively.*

THE BOARD CONTINUED

5) Mark Leahy [3]

INDEPENDENT NON-EXECUTIVE DIRECTOR

Mark Leahy is a capital markets expert with 22 years' of experience in the banking industry, holding high level positions for global investment banks such as Deutsche Bank, UBS, Nomura International and HSBC. Since 2014 Mark has been a Principal at M&A and capital solutions provider, Eaton Square, where he has been providing debt and market advice to M&A clients with a particular focus on facilitating the expansion plans of companies operating in Asia.

Prior to this role, Mark was a Non-Executive Director of former ASX listed Sherwin Iron Limited where he performed the role of Deputy Chairman during their restructuring process. Mark was also the Managing Director of Debt Origination and Syndication for Nomura International in Singapore where he was responsible for all primary debt risk taking in the region.

Mark was employed at Deutsche Bank from 2004 to 2009 in the role of Managing Director (Asian Regional Head, Global Risk Syndicate) where he built a market-leading primary debt syndication business and he was responsible for managing the bank's primary investment book in Asian credit instruments, with exposures ranging up to over USD$1 billion.

Mark has a Bachelor of Commerce (Finance and Accounting) from the University College Dublin. He has been representative of the National Association of Securities Dealers in the US, a representative of the UK Financial Services Authority and a Capital Markets Services licence from the Monetary Authority of Singapore.

Aside from his corporate finance career, Mark is also the co-founder and Executive Director of health and wellbeing retreat business, Legacy Retreats, and he is also an owner of a boutique vineyard in rural Australia. Mark has Irish and British citizenship and is a permanent resident in Singapore and Australia.

6) James (Mun Foong) Yip [3]

INDEPENDENT NON-EXECUTIVE DIRECTOR

Yip Mun Foong also known as James Yip, has nearly 30 years' banking experience with specific expertise in marketing and business origination, credit assessment, international capital markets, project finance and corporate finance. James' additional experience of managing a wholly-government owned investment company specialising in airport investment and consultancy, and furthermore managing an investment holding company in coal mine operations, has not only enhanced his leadership ability, but has also provided him with valuable and diverse industry experience to round out his strong banking and finance skill set.

From 2010 to 2012 James was an Independent Advisor to SC Fulfil Consulting Pte Ltd, where he provided advice on M&A, institutional and private equity, strategic direction and operational matters. Similarly, James also worked as an Independent Advisor to the Transportation Group of

HSH Nordbank AG (Germany), where he provided strategic advice for the securing of financing opportunities in Asia in the transportation infrastructure sector.

Prior to this James was managing a private investment holding company involved in the co-ownership and operations of open-pit coal mines in Indonesia. In addition to day-to-day operations, James was responsible for overseeing the trading of coal extracted, as well as opportunistic trading of other mineral resources such as nickel, manganese and iron to markets in Asia, most often to the People's Republic of China.

James has worked as the General Manager for Changi Airport Managers and Partners Pte Ltd, a wholly-owned subsidiary of the Civil Aviation Authority of Singapore, which specialises in the investment of overseas airports and the provision of airport management and consultancy services. In this role James had to interact with numerous external parties/agencies/consultants and frequently travelled to target countries to pitch investments to relevant authorities and to negotiate partnering/investment terms.

For close to the three decades before this, James had been employed in the financial services sector, having held the positions of Vice President and Head of Capital Markets / Syndications for Overseas Union Bank, Director – Corporate and Trade Finance for Rabobank Asia, and Senior Director – Capital Markets and Global Private Equity of Continental Bank N.A. He had also held various banking positions with First Chicago, Amro, Toronto-Dominion and Barclays Bank.

James is a member of the Singapore Institute of Directors, a Non-Executive Independent Director of Auhua Clean Energy plc, a mainland China company listed on the Alternative Investment Market (London) and he is Lead Independent Director of USP Group Limited, listed on the Singapore Exchange. James had also formerly been an Independent Director of Advance Modules Group Limited (Malaysia) and Zhenzhong Auto Components Limited (The Peoples Republic of China). He was also Lead Member of the audit committee of the Singapore Soka Association for three years until April 2012 as well as Vice Chairman of the School Advisory Committee of Outram Secondary School (alma mater) for the decade to July 2011.

James has an Executive Diploma in Directorship jointly awarded by the Singapore Institute of Directors and the Singapore Management University. He holds a postgraduate Diploma in Management Studies from the Graduate School of Business, University of Chicago and a postgraduate Diploma in Financial Management from New York University. Residing in Singapore, James was appointed to the Linc Energy Board on 3 August 2015.

** Notes:*

[3] Mark Leahy and James (Mun Foong) Yip were appointed to the Board of Linc Energy on 3 August 2015.

EXECUTIVE LEADERSHIP TEAM

1) Craig Ricato

CEO & MANAGING DIRECTOR

Craig Ricato was appointed as the CEO & Managing Director in October 2014. He brings a broad range of international experience to the Board across the regulatory, accounting and legal industries, together with a detailed understanding of Linc Energy's operations and assets developed over the previous seven years, to this role.

Craig was Linc Energy's Director, Legal and Corporate Affairs for over five years before resigning in June 2013 to pursue other opportunities outside of the Company. He continued to act as a non-executive director of Linc Energy until the appointment to his current role.

Craig obtained a Bachelor of Commerce degree in 1991 and was admitted as a Legal Practitioner of the Supreme Court of NSW and Queensland in 2001 after graduating with a Bachelor of Laws with First Class Honours. Craig has extensive experience working on legal and corporate matters related to the energy and resources industry, specifically with respect to cross-border transactions, international business structuring, mergers & acquisitions and equity capital markets. His early career background prior to joining the legal profession was in forensic accounting and law enforcement.

2) Michael Mapp

CHIEF OPERATING OFFICER

Michael is a respected and successful mining professional who has been working in the industry for more than 20 years. Michael joined Linc Energy from Intra Energy where he held the position of Chief Operating Officer.

Prior to Intra Energy, Michael worked with the Xstrata group as Operations Manager of Ulan Coal and before that as Director of Coal Operations Australia for Vale, responsible for operations including Carborough Downs, Isaac Plains, Broadlea and the Integra Coal underground and open-cut mines. He was promoted to Director after positions of Executive General Manager of Vale Australian Operations, Executive General Manager of Vale NSW Operations and General Manager of Integra Coal Operations with AMCI.

Additional mining experience was gained through Thiess Contractors as Plant Operations Manager and Director of Engineering & Operations Mining Technologies Australia, which oversaw the introduction and operation of highwall mining systems in Australia.

3) Chris Munday [4]

CHIEF FINANCIAL OFFICER

Chris Munday has in excess of 20 years' experience as a Chartered Accountant, including six years as a Partner in the Transaction Advisory Services division of global accounting group, Ernst & Young. During his career, Chris has gained extensive experience developing and implementing financial restructuring, refinancing and business growth strategies for publically listed companies.

Prior to joining Linc Energy in August 2015, Chris was employed in the role of Acting CFO at Guildford Coal Limited, an ASX listed mining company with coal mining operations in Mongolia and mining tenements in Queensland, Australia. In this role Chris was responsible for the financial, commercial, treasury and strategic management functions as the Company transitioned from an explorer to producer, and oversaw Guildford Coal's debt restructuring.

Chris is a Fellow of the Institute of Chartered Accountants in Australia and New Zealand and holds a Bachelor in Economics from the University of Adelaide.

4) Janelle van de Velde

CHIEF ADMINISTRATIVE OFFICER / COMPANY SECRETARY

Janelle van de Velde has over 25 years of experience working for publicly-listed companies. Janelle joined Linc Energy in August 2006 and in this time has held many diverse roles including investor relations, corporate communications and stakeholder relations.

In the role of Chief Administrative Officer and Company Secretary, Janelle is responsible for delivering a global communications strategy, incorporating corporate communications, media, stakeholder and government relations activities globally, while also administering the affairs of the Company and Business of the Board, including Linc Energy's adherence to its corporate governance policies. Janelle is also responsible for ensuring the required business services such as IT, telecommunications, travel and administration support the Company's requirements.

[4] *Chris Munday began employment as Linc Energy's Chief Financial Officer on 3 August 2015. The previous incumbent of this role, Stuart Jones resigned on 30 March 2015.*

FINANCIALS

FOR THE YEAR ENDED 30 JUNE 2015

CORPORATE GOVERNANCE STATEMENT

Linc Energy Ltd and its Board of Directors (Board) are committed to achieving and demonstrating the highest standards of corporate governance. The Board guides and monitors the Company's activities on behalf of our Shareholders. In developing policies and standards the Board considers the SGX Code of Corporate Governance 2012 (the "2012 Code"). The Corporate Governance Statement set out below describes, as at 30 June 2015, the Company's corporate governance principles and practices which the Board considers to comply with the 2012 Code. Any deviations from the Code are accompanied with appropriate explanations.

We recognise the importance of corporate governance and the maintenance of high standards of accountability to our Shareholders.

BOARD MATTERS

THE BOARD'S CONDUCT OF AFFAIRS

PRINCIPLE 1: *The Board is responsible for the overall corporate governance of the Company. The Board recognises the need for the highest standards of behaviour and accountability. The Board has overall responsibility for the management of the Company's business and affairs.*

The responsibilities addressed by the Board are:

a) Approving the Company's goals, strategic direction and monitor implementation of those goals and strategies;
b) Monitoring the financial performance of the Company including adopting annual budgets and approving the Company's financial statements;
c) Approving and monitoring the progress of capital expenditure, capital management, acquisitions and divestitures;
d) Ensuring that adequate systems of internal compliance and controls exist and are appropriately monitored for compliance;
e) Appointing and removing the Chief Executive Officer (CEO) and Managing Director and ratifying the appointment of the Chief Financial Officer (CFO) and Company Secretary and reviewing the performance of senior management;
f) Ensuring significant business risks are identified and appropriately managed and review the system of risk management at least annually;
g) Reviewing and ratifying codes of conduct and legal compliance; and
h) Disclosure of information to shareholders, the Singapore Exchange Securities Trading Limited (SGX) and Australian Securities and Investments Commission (ASIC).

The Board operates under a written charter (Board Charter) that identifies the functions reserved for the Board. Management of the day-to-day operations of the Company vests in the CEO and Managing Director who, together with the executive team, is accountable to the Board.

The following decisions have been reserved for the Board:

a) Any announcement to the SGX;
b) Any employment contract in excess of AUD$300,000;
c) Any staff incentive program or material changes thereto;
d) Any material contract including contracts for a value greater than AUD$12 million (within budget) and AUD$2 million (outside of budget);
e) Any financial instruments exceeding AUD$10 million;
f) Any financial indebtedness exceeding AUD$10 million;

g) Creation of any security over the Company's assets;
h) Any share option or other security, rights of derivative issue other than share options included in employment agreements;
i) Commencement of any legal proceedings relating to a claim or potential claim in excess of AUD$2.5 million;
j) Making a change in financial year end; and
k) Any decision to seek a capital raising by the Company.

All other decisions which involve operations in the ordinary course of business are vested in the CEO and Managing Director including carrying out decisions of the Board and matters incidental to those decisions and shall include the ability to recommend any of the matters in a) to k) above. In exceptional circumstances, the CEO and Managing Director may, after consultation with the Chairman, enter into a transaction requiring Board ratification where time is of the essence. The bank account authority is to require the signature of any two directors of the Company.

Meetings & Attendance

The Company has three committees, the Audit and Risk Management Committee, the Nominating Committee and the Remuneration Committee. On 11 May 2015, the Board resolved to amalgamate the Nominating Committee and Remuneration Committee to form the Nominating and Remuneration Committee effective 1 July 2015.

Following the appointment of two new Independent Non-Executive Directors in August, the Board resolved on 24 August 2015 that the membership of the committees are:

* *Audit and Risk Management Committee:* Mr James Yip, Mr Mark Leahy and Mr Kenneth Dark.

* *Nominating and Remuneration Committee* Mr James Yip, Mr Mark Leahy and Mr Kenneth Dark.

The schedule of all Board and Board Committee meetings is planned in advance. The Board has formal meetings and meets regularly during the year as required. Due to directors being located in different parts of the world, telephonic and video conferencing facilities are occasionally used to conduct meetings. The Board and Board Committees may also make decisions by way of circulating written resolutions.

The number of meetings of the Board and of each Board Committee held during the year ended 30 June 2015, and the number of meetings attended by each director were:

	Full meetings of Directors		Meetings of Audit and Risk Management Committee		Remuneration Committee		Nominating Committee	
	A	B	A	B	A	B	A	B
Craig Ricato	9	9	2	2	-	-	-	-
Peter Bond	9	9	-	-	-	-	-	-
Kenneth Dark	8	9	4	4	2	2	1	2
Lim Ah Doo[1]	8	8	6	6	-	-	2	2
Jon Mathews	8	9	4	6	2	2	-	-
Koh Ban Heng[2]	7	7	-	-	2	2	2	2
Ong Tiong Soon[3]	1	1	-	-	-	-	-	-

A = Number of meetings attended during the time the director held office or was a member of the committee.
B = Number of meetings held during the time the director held office or was a member of the committee during the year.
[1] Mr Lim Ah Doo resigned on 23 June 2015.
[2] Mr Koh Ban Heng resigned on 22 May 2015.
[3] Mr Ong Tiong Soon was appointed on 28 May 2015.

New Directors

New directors receive a formal letter of appointment along with an induction pack. The contents of the appointment letter and induction pack contain sufficient information to allow the new director to gain an understanding of:

- The Company's financial, strategic, operational and risk management position;
- The rights, duties and responsibilities of directors;
- The Company's Constitution and Corporate Governance policies;
- The roles and responsibilities of the Executive Team; and
- The role of Board Committees.

New directors are also subject to an orientation day to ensure they are familiar with the Company's business and governance practices and understand their duties and responsibilities.

In consultation with our legal and financial service providers, the Company ensures training is available to all new directors upon appointment and this is reviewed regularly throughout the Board tenure as required. Updates on new laws and changes in laws and regulations are provided as required.

BOARD COMPOSITION AND GUIDANCE

PRINCIPLE 2: *There should be a strong and independent element on the Board, which is able to exercise objective judgement on corporate affairs independently, in particular, from Management and 10% of shareholders. No individual or small group of individuals should be allowed to dominate the Board's decision making.*

Composition of the Board

The Board's size and composition is subject to limits imposed by the Company's Constitution, which provides for a minimum of three directors and a maximum of ten directors. At 30 June 2015, the Board was composed of five directors with diverse skills and experience, relevant to the business of the Company and the benefits of these skills and experience add value to the Company's operations. Subject to the Company's Constitution, each director (with the exception of the Managing Director) must not hold office (without re-election) past the third annual general meeting following the director's appointment of three years, whichever is longer.

The composition of the Board is reviewed annually to ensure that it has available, an appropriate mix of skills and experience to ensure the interests of shareholders are served. Potential nominations to the Board are assessed by the Board as a whole.

Board Independence

At 30 June 2015, the Company was not compliant with board independence as independent directors did not make up at least half of the Board. The Board was comprised of five directors but only two were independent directors, Mr Kenneth Dark and Mr Jon Mathews. The Company was compliant with this principle during the financial year until the departure of Independent Non-Executive Director Mr Lim Ah Doo on 23 June 2015. The Company has rectified this situation with the recent appointment of two Independent Non-Executive Directors on 3 August 2015, Mr Mark Leahy and Mr James (Mun Foong) Yip.

The predominance of Non-Executive Directors separates the Board from the Company's executive management and enshrines Board independence from management. This structure also provides the Company with the benefit of a diverse range of experience, qualifications and professional skills relevant to the business of the Company.

The Board (and each individual director) is entitled to seek independent professional advice at the Company's expense (subject to the reasonableness of the costs and Board consent) in the conduct of their duties for the Company.

In assessing independence, the Board reviews the relationship that the Director and their immediate family have with the Company. In particular the Board applies the following criteria in determining independence:

A Director and their immediate family:

1. Is not a shareholder of the Company holding more than five per cent of the voting shares or an officer of, or otherwise associated directly with, a shareholder of the Company holding more than five per cent;
2. Within the last three years has not been employed in an executive capacity by the Company or another Group member, or been a director after ceasing to hold any such employment;
3. Within the last three years has not been a principal of a material professional adviser or a material consultant to the Company or another Group member, or an employee materially associated with the service provider;

4. Is not a material supplier or customer of the Company or other Group member, or an officer of or otherwise associated directly or indirectly with a material supplier or customer;
5. Has no material contractual relationship with the Company or another Group member other than as a director of the Company;
6. Has not served on the Board for a period which could, or could reasonably be perceived to, materially interfere with the director's ability to act in the best interests of the Company; and
7. Is free from any interest and any business or other relationship which could, or could reasonably be perceived to, materially interfere with the director's ability to act in the best interests of the Company.

The Board regularly assesses the independence of Non-Executive Directors and has specifically considered the independence of all Non-Executive Directors, in accordance with the above criteria, during the financial year.

On 11 May 2015, the Board resolved to amend Mr Kenneth Dark's status to Independent Director as he has served as an Non-Executive Director for more than nine years, ensuring Guidelines 2.3 and 2.4 of the 2012 Code were satisfied and in recognition of Mr Dark's ability to exercise objective judgement and his independent character in relation to the Company's affairs.

Mr Ong Tiong Soon is the only Non-Executive Director who is not independent as he is the Chief Executive Officer of the Energy division of Genting Berhad which is a substantial shareholder of the Company.

CHAIRMAN AND CHIEF EXECUTIVE OFFICER

PRINCIPLE 3: *There should be a clear division of responsibilities between the leadership of the Board and the executives responsible for managing the company's business, No one individual should represent a considerable concentration of power.*

The Company has a separate Chairman and CEO to ensure an appropriate balance of power, increased accountability and greater capacity of the Board for independent decision making.

The Chairman of the Board is Mr Peter Bond and in accordance with the Company's Board Charter is responsible for:

- Leadership of the Board;
- Chair Board meetings and shareholder meetings;
- Efficient organisation and conduct of the Board's function;
- Briefing all directors in relation to issues arising at Board meetings;
- Facilitating effective contribution by all directors;
- Overseeing that membership of the Board is skilled and appropriate for the Company's needs;
- Promoting constructive and respectful relations between Board members and between the Board and management;
- Reviewing corporate governance matters with the Company Secretary and reporting on those matters to the Board; and
- Monitoring Board performance.

The role of CEO and Managing Director is performed by Mr Craig Ricato. Mr Ricato is responsible to the Board for the overall development of strategy, management and performance of the Company. He manages the organisation in accordance with the strategy, business plans and policies approved by the Board to achieve the agreed goals.

The CEO along with the CFO will also state in writing to the Board that:

1. The Company's financial reports and accompanying notes represent a true and fair view in all material respected of the Company's financial condition and operational results and are in accordance with relevant accounting standards;

2. The statement referred to in paragraph (1) is founded on a sound system of risk management and internal compliance and control which implements the policies adopted by the Board; and

3. The Company's risk management and internal compliance and control system is operating efficiently and effectively in all material respects.

Lead Independent Director

Mr Lim Ah Doo was the Non-Executive Lead Independent Director of the Company until his resignation on 23 June 2015. This role is available to our Shareholders where they have concerns for which contact through the normal channels of Chairman, CEO and Managing Director or CFO has failed to resolve or is inappropriate. This position has been filled by Independent Non-Executive Mr Mark Leahy on 22 September 2015.

BOARD MEMBERSHIP

PRINCIPLE 4: *There should be a formal and transparent process for the appointment and re-appointment of directors to the Board.*

The Board has established a Nominating Committee (NC) which must consist of at least three members, the majority of whom, including the NC Chairman, should be independent and not directly associated with a substantial shareholder (with an interest of 5 per cent or more in the voting shares of the Company). The Lead Independent Director must also be a member.

The frequency of the meeting will be at least once a year and to meet as and when necessary to achieve the objectives. The NC chairman will schedule the meeting with the Company Secretary which will be the secretary of the NC. The Company Secretary will issue a notice of meeting and take minutes. All NC resolutions will be by majority vote with the Chairman having the casting vote in the case of equal votes.

The NC was chaired by Independent Non- Executive Director Mr Koh Ban Heng until his resignation on 22 May 2015. Lead Independent Director, Mr Lim Ah Doo was a committee member until his resignation on 23 June 2015 and Independent Director, Mr Kenneth Dark was also a member. No replacement members were appointed as the NC and Remuneration Committee were amalgamated on 1 July 2015.

The NC shall:

1. Be responsible for the nomination of all directors to the Board after having reviewed the background, academic and professional qualifications, experience and independence for Board membership. In any re-nomination/re-appointment of a director and before recommendation to the Board, the NC should assess whether each director continues to contribute effectively and demonstrate commitment to the role (including commitment of time for Board and committee meetings, and any other duties). The Chairman should act on the results of the performance evaluation, and where appropriate, propose new members be appointed to the Board or seek the resignation of directors, in consultation with the NC;
2. Implement the process for the selection and appointment of new directors to the Board including the search and nomination process;
3. Ensure all directors submit themselves for renomination and re-election at least once in every three years and justify any departure to this policy;
4. Determine on an annual basis if a director is independent;
5. Determine annually whether a director with multiple board representation is able to and has been adequately carrying out his duties as a director of the Company through an assessment of the effectiveness and contributions of the individual director;
6. Propose and implement objective performance criteria to evaluate the performance and effectiveness of the Board; and
7. Review of board succession plans for the Chairman, CEO and the directors.

The Board has not specified a maximum number of listed company board representations a director may hold. An annual assessment is made by the NC to assess the Director's performance and whether they have adequately carried out their responsibilities. The NC believes that limiting the number of board representations a director can hold is not required given the time requirements for each role may differ. A director is responsible for fulfilling their duties and responsibilities and if they find themselves unable to do so, the Board must be informed and the director may be asked to step down.

On 11 May 2015, the Board resolved to amalgamate the Nominating Committee and Remuneration Committee effective 1 July 2015, As at 30 June 2015, the Committee members were Mr Kenneth Dark as Interim Chairman until a permanent appointment was made and Mr Jon Mathews as the remaining committee member. Following the resignation of Mr Jon Mathews on 31 July 2015 and the appointment of two Independent Non-Executive Directors, Mr Mark Leahy and Mr James (Mun Foong) Yip, the membership as at 22 September 2015 consists of Mr James (Mun Foong) Yip as Chairman, Mr Mark Leahy (as Lead Independent Director) and Mr Kenneth Dark.
Key information regarding directors' academic and professional qualifications, shareholdings in the Company, board committees and current directorships and those held over the preceding three years in other listed companies can be found in the Board biographies and the Directors' Report.

BOARD PERFORMANCE

PRINCIPLE 5: *There should be a formal annual assessment of the effectiveness of the Board as a whole and its board committees and the contribution by each director to the effectiveness of the Board.*

The NC proposes to the Board objective performance criteria to evaluate the performance and effectiveness of the Board as a whole and each of its members. The current criteria was pre-approved by the Board on 11 May 2015 and should not be changed from year to year unless justified by the Board. The performance criteria allows comparison with industry peers and addresses how the Board has enhanced long-term shareholders' value and taken into consideration the Company's share price performance over a five year period *vis-à-vis* the Singapore Straits Times Index and a benchmark index of its industry peers.

The Board undertakes an annual performance evaluation of itself and the effectiveness of its members in the first quarter of the financial year that:

- Compares the performance of the Board and its members with the requirements of the Board Charter;
- Sets forth the goals and objectives of the Board for the upcoming year; and
- Effects any improvements to the Board Charter that are necessary or desirable.

The Board also discusses with each director their requirements, performance and aspects of involvement in the Company.

ACCESS TO INFORMATION

PRINCIPLE 6*:* *In order to fulfil their responsibilities, directors should be provided with complete, adequate and timely information prior to board meetings and on an on-going basis so as to enable them to make informed decisions to discharge their duties and responsibilities.*

Management has an obligation to provide adequate and timely information to the Board on the Company's affairs and issues that require the Board's decision as well as ongoing reports relating to operational and financial performance. The Board is provided with Management's updates in Board papers, in monthly Management reports provided in between formal Board meetings and in background information provided with any proposed resolution provided to the Board for its consideration.

In relation to financial matters, any material variance between budgeted and actual results is required to be disclosed with sufficient information to explain the variance. Directors of the Company are entitled to liaise directly with key members of Management and to seek additional (or clarification of) information.

Company Secretary

The Board is supported by the Company Secretary who is accountable to the Board through the Chairman on all corporate governance matters.

The Company Secretary is responsible for:

- Monitoring compliance with Board policy and procedures;
- Coordinating the completion and circulation of the Board agenda and briefing materials;
- Organising Board meetings and director attendance;
- Providing a point of reference for all dealings between Board and management; and
- Ensuring the Company complies with its regulatory requirements.

The appointment or removal of the Company Secretary is subject to the approval of the Board.

Independent Professional Advice

If necessary, our directors are able to seek and obtain independent professional advice to assist them in their duties, at the expense of the Company.

REMUNERATION MATTERS

PROCEDURES FOR DEVELOPING REMUNERATION POLICIES

PRINCIPLE 7: *There should be a formal and transparent procedure for developing policy on executive remuneration and for fixing the remuneration packages of individual directors. No director should be involved in deciding his own remuneration.*

Remuneration Committee

The Board has established a Remuneration Committee (RC) to support and advise the Board by setting and implementing appropriate remuneration and benefits policies and systems to:

- attract, retain and motivate executives, directors and employees for the long-term growth and success of the Company;
- enhance Company and individual performance for the benefit of shareholders;
- demonstrate to investors a clear relationship between performance and remuneration; and
- support the Company's goals and values.

The RC must have at least three members, all of whom have to be non-executive and a majority of whom have to be independent, including the Chairman. The RC is comprised of the Chairman, Mr Jon Mathews and committee members, Mr Kenneth Dark and Mr Koh Ban Heng until his resignation on 22 May 2015. In light of the Board's resolution to amalgamate the Remuneration Committee and the Nominating Committee on 11 May 2015, Mr Koh Ban Heng's role was not replaced on the Nominating Committee following his departure. The RC did not meet following Mr Koh Ban Heng's departure.

The members of the newly formed Nominating and Remuneration Committee, effective 1 July 2015, was Mr Kenneth Dark as Interim Chairman (until a permanent appointment was made) and Mr Jon Mathews as the remaining committee member. Following the resignation of Mr Jon Mathews on 31 July 2015 and the appointment of two Independent Non-Executive Directors, Mr Mark Leahy and Mr James (Mun Foong) Yip, the membership as at 22 September 2015 consists of Mr James (Mun Foong) Yip as Chairman, Mr Mark Leahy (as Lead Independent Director) and Mr Kenneth Dark.

The RC is responsible for, among others, recommending to the Board a framework and criteria of remuneration for the directors and key executives, including the review of interested person transactions that relate to remuneration matters, and for recommending specific remuneration packages for each director and the CEO. The recommendations of the RC are submitted for endorsement by the entire Board, subject to the requirement that no individual is directly involved in deciding their own remuneration. All aspects of remuneration, including but not limited to directors' fees, salaries, allowances, bonuses, rights and benefits in kind is covered by the RC.

All decisions at any meeting of our RC shall be decided by a majority of votes of the members present and voting and such decision shall at all times exclude the vote, approval or recommendation of any member who is interested in the subject matter under consideration.

The RC seeks the assistance of external expert advice as necessary when designing or approving executive remuneration structures. PricewaterhouseCoopers was utilised in the design of the current Short-Term Incentive Plan, and AON Hewitt is utilised for annual industry remuneration reports. No remuneration consultants from PricewaterhouseCoopers or AON Hewitt have an existing relationship with the Company. Further details on the Short-Term Incentive Plan are detailed in Principle 9.

LEVEL AND MIX OF REMUNERATION

PRINCIPLE 8: *The level and structure of remuneration should be aligned with the long-term interest and risk policies of the company, and should be appropriate to attract, retain and motivate (a) the directors to provide good stewardship of the company, and (b) key management personnel to successfully manage the company. However, companies should avoid paying more than is necessary for this purpose.*

Remuneration of Executive Directors and Key Management Personnel

The remuneration packages of Executive Directors and Key Management Personnel comprise both fixed and variable components and non-monetary benefits.

The fixed component consists of a base salary and superannuation contributions (if applicable). The RC ensures that the remuneration of Executive Directors and Key Management Personnel is consistent and comparable to market practice through industry remuneration surveys, and directly reviewing and considering remuneration components against those of comparable companies if such information is publicly available.

The variable component of remuneration comprises a variable annual bonus or short-term incentive (STI) based on the Company and individual executive's performance in relation to predetermined key performance indicators (KPI's).

Total bonuses payable are reviewed by the RC and approved by the Board. The Board considers the performance bonus a mechanism to support the Company business strategy, and further enhance shareholder value through delivery by the Company of annual strategic, financial and operational objectives.

Non-monetary benefits may also form part of remuneration. These can include the provision of a motor vehicle, parking allocation, accommodation and other benefits as approved by the RC.

Remuneration of Non-Executive Directors

Non-Executive Directors are paid director's fees, not exceeding the maximum aggregate annual remuneration as approved by Shareholders at the 2013 Annual General Meeting. Each Non-Executive Director is paid a base director fee with additional fees paid per committee membership. The Chairman of the Board and Chairman of each Board Committee is paid a higher fee compared to the members of the respective committees in view of the greater responsibility carried by that office. The basic fee structure for the 30 June 2015 financial year is disclosed in the table below:

Non-Executive Role	Base Non-Executive Director fee (SGD)	Audit Committee fee (SGD)	Nominating Committee fee (SGD)	Remuneration Committee fee (SGD)
Chairman/Committee Chairman	$180,000	$50,000	$30,000	$30,000
Member	$130,000	$30,000	$20,000	$20,000

The Lead Independent Director also receives an additional SGD$20,000 per annum.

If a Non-Executive Director occupies a position for part of the financial year, the fee payable is pro-rated accordingly.

The directors resolved on 11 May 2015 to realise a twenty per cent pay reduction in their remuneration commencing 1 July 2015. The basic fee structure from 1 July 2015 is disclosed in the table below:

Non-Executive Role	Base Non-Executive Director fee (SGD)	Audit Committee fee (SGD)	Nominating & Remuneration Committee fee (SGD)
Chairman/Committee Chairman	$144,000	$40,000	$24,000
Member	$104,000	$24,000	$16,000

From 1 July 2015, the Nominating Committee and Remuneration Committee have been amalgamated.

The Lead Independent Director also receives an additions SGD$16,000 per annum.

DISCLOSURE ON REMUNERATION

PRINCIPLE 9: *Every company should provide clear disclosure of its remuneration policies, level and mix of remuneration, and the procedure for setting remuneration, in the company's Annual Report. It should provide disclosure in relation to its remuneration policies to enable investors to understand the link between remuneration paid to directors and key management personnel, and performance.*

During the financial year the Board approved a Short-Term Incentive Plan for all employees. The Short-Term incentive Plan (which is not equity based) has replaced the Performance Rights Plan which was approved by Shareholders at the annual general meeting in 2009. All employees' have now been transitioned from the Performance Rights Plan to the Short-Term Incentive Plan.

Performance Rights Plan

The Performance Rights Plan sought to align the interest of eligible employees with the future growth and development of the Company. The provision for the Performance Rights Plan to vest in multiple tranches over multiple years provided the balance between the objectives of attracting and retaining high performing employees and aligning the interests of these employees with the shareholders in the long term

The number of rights granted was determined at the discretion of the Board and based on a formula taking into account an employee's base salary and the Company's share price at the time of grant. The Rights typically vested in in either three or four equal tranches over a period of three and half to four and half years, with the first tranche vesting twelve months from the successful completion of probation period. Rights were granted at no cost to the participant and may have included non-market-based performance conditions. The rights automatically converted to shares on the vesting date provided all vesting conditions were met. Rights granted under the plan carried no dividend or voting rights until they converted to ordinary shares. This plan has closed and has been replaced by the Short-Term Incentive Plan. No rights remain outstanding.

Short-Term Incentive Plan

The Short-Term Incentive (STI) Plan is a bonus plan for all employees which provides an incentive that aligns reward with shorter term Company and individual performance. STI awards are based on performance over the financial year and paid in cash, at the sole discretion of the Company, at the conclusion of each performance period.

As part of the Company's annual strategic planning process, overall Company performance objectives will be established which will include budget performance and health, safety and environmental compliance objectives. Each employee will also be set individual performance objectives which are qualitative measures derived from the Company's strategic plan.

An employee's total STI award will be calculated based on achievement of the Company and/or divisional objectives, as well as their individual achievement against their performance objectives. The percentage weighting between the Company and individual objectives is determined by the seniority of the employee within the business, and the stratum banding within which their role sits.

The plan was introduced in January 2015 with the first performance period being pro-rated for six months to the end of June 2015.

ANNUAL REMUNERATION REPORT

A breakdown showing the level and mix of each individual director's remuneration paid or payable for the financial year under review is disclosed in the table below:

DIRECTORS	Short term			Post-employment	Share-based payments[2]	
Remuneration Bands	Fees	Cash bonus[1]	Non-monetary benefits	Super-annuation	Rights	Total
	$	$	$	$	$	$
SGD$2,000,001 – SGD$2,250,000						
Peter Bond	1,998,356	-	12,762	189,844	-	2,200,962
SGD$1,750,001 – SGD$2,000,000						
Craig Ricato	1,186,936	591,908	4,602	112,759	-	1,896,205
SGD$250,001 – SGD$500,000						
Lim Ah Doo[3]	278,613	-	-	-	-	278,613
Jon Mathews	190,000	-	1,629	18,050	33,089	242,768
Kenneth Dark	205,000	-	-	19,475	-	224,475
Koh Ban Heng[4]	204,690	-	-	-	-	204,690
Below SGD$250,000						
Ong Tiong Soon[5]	12,110	-	-	1,150	-	13,260

[1] The cash bonus was a success fee for assisting the Company in arranging additional funding for the US Oil and Gas business.

[2] The values shown in the table above for share-based payments reflects the assessed fair value of the share-based payment calculated in accordance with accounting standards and recognised as a non-cash expense for each person during the year. These figures do not represent the actual cash value of the share rights vested during the period.

[3] Mr Lim Ah Doo's remuneration is for the period he was an Independent Non-Executive Director until 23 June 2015.

[4] Mr Koh Ban Heng's remuneration is for the period he was an Independent Non-Executive Director until 22 May 2015.

[5] Mr Ong Tiong Soon's remuneration is for the period he was a Non-Executive Director from 28 May 2015.

The Board of Directors resolved on 11 May 2015 to realise a twenty per cent pay reduction in their remuneration commencing 1 July 2015.

Other than the CEO, the Company has three (not five) key executives who are considered key management personnel. These are members of the Executive Leadership team who have the authority and responsibility for planning, directing and controlling activities of the Company. A breakdown showing the level and mix of remuneration of Key Executives remuneration paid or payable for the financial year under review is shown in the table below.

KEY EXECUTIVES	Short term		Post-employment		Long term benefits	Share-based payments[2]	
Remuneration Bands	Cash salary	Non-monetary benefits	Super-annuation	Termination benefits	Long Service leave[1]	Rights	Total
	%	%	%	%	%	%	%
SGD$750,001 – SGD$1,000,000							
Michael Mapp	83	8	8	-	1	-	100
SGD$250,001 – SGD$500,000							
Janelle van de Velde	77	11	7	-	5	-	100
Stuart Jones	71	-	8	21	-	-	100

[1] The values shown in the table above for long service leave reflects the amount accrued for the financial year.
[2] The values shown in the table above for share-based payments reflects the assessed fair value of the share-based payment calculated in accordance with accounting standards and recognised as a non-cash expense for each person during the year. These figures do not represent the actual cash value of the share rights vested during the period.

The aggregate total remuneration paid or payable to the key executives (who are not directors or the CEO) for the year ended 30 June 2015 was SGD$1,875,900.

Remuneration of Employee Related to Director

One of Mr. P Bond's children was employed by the Company and his annual remuneration exceeds SGD$50,000 as per the percentage breakdown below:

IMMEDIATE FAMILY MEMBER OF DIRECTOR	Short term		Post-employment		Long term benefits	Share-based payments[2]	Total
Remuneration Band	Cash salary	Non-monetary benefits	Super-annuation	Termination benefits	Long Service leave [1]	Rights	Total
	%	%	%	%	%	%	%
SGD$100,002 – SGD$150,000							
A. J. Bond	89	-	8	-	1	2	100

[1] The values shown in the table above for long service leave reflects the amount accrued for the financial year.
[2] The values shown in the table above for share-based payments reflects the assessed fair value of the share-based payment calculated in accordance with accounting standards and recognised as a non-cash expense for each person during the year. These figures do not represent the actual cash value of the share rights vested during the period.

Performance Rights Plan

Set out below is the movement of rights under the Performance Rights Plan to directors of the Group, including their related parties during the financial year. No rights remain outstanding at the end of the financial plan and the Plan is no longer operational.

DIRECTORS Name	Balance at start of year Number	Number of rights granted as compensation during year Number	Vested during the year Number	Forfeited during the year Number	Unvested balance at end of the year Number
2015					
Peter Bond[1]	15,169	-	(5,912)	(9,257)	-
Jon Mathews	125,000	-	(125,000)	-	-

[1] Peter Bond's rights were held by related parties.

Set out below is the movement of rights under the Performance Rights Plan to Key Executives of the Group, including their related parties during the financial year.

KEY EXECUTIVES Name	Balance at start of year Number	Number of rights granted as compensation during year Number	Vested during the year Number	Forfeited during the year Number	Unvested balance at end of the year[1] Number
2015					
Michael Mapp	-	2,000	(2,000)	-	-
Stuart Jones	800,000	-	(200,000)	(600,000)	-

[1] Or date ceased to be a key management person.

Interested person transactions

The following table shows the aggregate value of interested person transactions entered into during the financial year ended 30 June 2015:

Name of Interested person	Aggregate value of all interested person transactions during the financial year under review (excluding transactions less than SGD$100,000 and transactions conducted under shareholders' mandate pursuant to SGX Mainboard Listing Rule 920)	Aggregate value of all interested person transactions conducted under shareholders' mandate pursuant to SGX Mainboard Listing Rule 920 (excluding transactions less than SGD$100,000)
Peter Bond	746,258	Not applicable

[1] The Company expects to receive a repayment of SGD$746,258 from Bond Air Charters Pty Ltd, a related party of Peter Bond, for the return of unused charter flight funds that were prepaid in advance in May 2014.

ACCOUNTABILITY AND AUDIT

ACCOUNTABILITY

PRINCIPLE 10: *The Board should present a balanced and understandable assessment of the company's performance, position and prospects.*

The Board understands its responsibility to provide Shareholders its assessment of the Company's performance, position and future strategic goals. Quarterly financial statement announcements, the annual report, investor presentations and regular SGX announcements on the Company's progress are provided. Reports are provided to regulators as dictated by legislation.

The Company's Management aims to provide the Board with all relevant information to enable the Board to fulfil its role effectively. The Board is provided with Management's updates in Board papers, in monthly management reports provided in between formal Board meetings and in background information provided with any proposed resolution provided to the Board for its consideration. In relation to financial matters, any material variance between budgeted and actual results is required to be disclosed with sufficient information to explain the variance. Directors of the Company are entitled to liaise directly with key members of Management and to seek additional or clarification of information.

The Company has established a number of policies to ensure that it complies with legislative and regulatory requirements. These include, but are not limited to the following:

- Audit & Risk Management Committee Policy;
- Board Charter;
- Code of Conduct;
- Continuous Disclosure Policy;
- Corporate Governance Practices and Policies;
- Diversity Policy;
- Environmental Policy;
- Ethical Business Conduct Policy;
- Health and Safety Policy;
- Privacy Policy;
- Related Party Transaction Policy;
- Securities Trading Policy;
- Shareholder Communications Policy;
- Terms of Reference of the Nominating and Remuneration Committee; and
- Whistleblower Policy.

The above Company Policies are available on the Company's website.

RISK MANAGEMENT AND INTERNAL CONTROLS

PRINCIPLE 11: *The Board is responsible for the governance of risk. The Board should ensure that Management maintains a sound system of risk management and internal controls to safeguard shareholders' interests and the company's assets, and should determine the nature and extent of the significant risks which the Board is willing to take in achieving its strategic objectives.*

The Board is responsible for ensuring significant business risks are identified and appropriately managed and review the system of risk management at least annually. They also ensure that adequate systems of internal controls exist and are appropriately monitored for compliance. The Audit and Risk Management Committee (ARMC) assists the Board in its oversight of risk governance and internal controls.

The Company maintains a formal risk management register which details the principal risks which may adversely impact the performance of the Group and the Company's ability to execute its strategies. Once key risks are identified, each risk is assigned to the relevant person within the business who is responsible for implementing a strategy to mitigate the risk where they are within the Group's control and ongoing monitoring.

There are areas of the Group's business where it is necessary to accept risks to achieve a satisfactory return for Shareholders, such risks reflecting the Board's overall appetite for risk. It is the Group's objective to apply expertise to prudently manage rather than eliminate such risks by keeping them under frequent review.

Management provides monthly reports to the Board which include the identification of material business risks and matters relating to the effectiveness of the Company's management of its material business risk.

To ensure that the system of risk management and internal controls are appropriate, the Company engages various independent professional firms to undertake external and internal audits and reviews. Findings and recommendations for improvements are presented to the ARMC to enable the ARMC to assess the effectiveness of internal controls.

In the prior financial year, Protiviti Pty Ltd was engaged as an internal auditor to undertake a risk and internals control assessment. This work was completed in the current financial year. Further information is detailed in Principle 13.

The Board has received written assurances from the CEO and CFO in the form of representation letters prior to approving the Company's Annual Report that:

1. the Company's financial reports and accompanying notes represent a true and fair view in all material respects of the Company's financial condition and operational results and are in accordance with the relevant accounting standards;
2. the statement referred to in paragraph (1) is founded on a sound system of risk management and internal compliance and control which implements the policies adopted by the Board; and
3. the Company's risk management and internal compliance and control system is operating efficiently and effectively in all material respects.

Based on the internal controls established and maintained by the Company and performance reviews by Management, the ARMC and Board are of the opinion that the Company's internal controls, addressing financial, operational, compliance, information technology controls and risk management systems were adequate and effective as at 30 June 2015.

AUDIT AND RISK MANAGEMENT COMMITTEE

PRINCIPLE 12: *The Board should establish an Audit Committee ("AC") with written terms of reference which clearly set out its authority and duties.*

Audit Committee

The Company has established an Audit and Risk Management Committee (ARMC) which operates in accordance with the Audit and Risk Management Committee Policy. The primary objective of the ARMC is to assist the Board in ensuring that management maintains a sound system of risk management and internal controls to safeguard shareholders' interests and the Company's assets, and should determine the nature and extent of the significant risks which the Board is willing to take in achieving strategic objectives.

The ARMC must have at least three members all of whom must be Non-Executive Directors and the majority of whom, including the Chairman, must be independent. Under the policy, the Chairman of the ARMC must not be the Chairman of the Company and should include members who are financially literate (i.e. are able to read and understand financial statements) with at least two members, including the Chairman having recent accounting or related financial management expertise or experience and some members who have an understanding of the industries within which the Company operates.

Members are appointed for an initial term of three years after which they will be eligible for reappointment by rotation. The terms of members shall be staggered so that at least one member shall stand for reappointment every three years, and at least one new member is appointed in each three year cycle. The role of Chairman shall rotate between members. The maximum term as Chairman is six consecutive years.

At 30 June 2015, the Company was non compliant as the Committee only had two members, Mr Kenneth Dark and Mr Jon Mathews following the resignation of the Chairman of the ARMC, Mr Lim Ah Doo on 23 June 2015. The Company has rectified this with the appointment of two Independent Non-Executive Directors, Mr Mark Leahy and Mr James (Mun Foong) Yip to the ARMC on 24 August 2015 who both have extensive financial expertise. The Committee members as of this date are Mr Mark Leahy (appointed Chairman and Lead Independent Director as at 22 September 2015), Mr James (Mun Foong) Yip and Mr Kenneth Dark.

The ARMC have explicit authority to investigate any matter within its terms of reference, full access to and co-operation by management and full discretion to invite any director or Executive Officer to attend its meetings including the CEO and Managing Director, CFO and Company Secretary, and reasonable resources to enable it to discharge its functions properly.

The ARMC duties and responsibilities are as follows:

1. recommend to the Board the proposal to shareholders on the appointment, re-appointment and removal of the external auditors, and approving the remuneration and terms of engagement of the external auditors;
2. recommend to the Board the appointment of any internal auditors and approve the audit plan of the internal auditors;
3. ensure that management is fully cooperative with both the external and any internal auditors;
4. oversee the adequacy of controls established by executive management to identify and manage areas of potential risk and to safeguard the Company’s assets;
5. review significant financial reporting issues so as to ensure the integrity of the financial statements of the Company;
6. review and report to the Board at least annually on the adequacy and effectiveness of our internal control systems, including financial, operational, compliance and information technology controls (such reviews can be carried out internally or with the assistance of any competent third parties);
7. review the scope and results of the external audit, and the independence and objectivity of the external auditors;
8. evaluate the processes in place to ensure that accounting records are properly maintained in accordance with statutory requirements and financial information provided to shareholders and the directors is accurate and reliable;
9. review filings with the Singapore Exchange Securities Trading Limited (SGX-ST) or other regulatory bodies which contain the Company’s financial information to ensure proper disclosure;
10. review interested persons transactions or the transactions that may lead to conflicts of interest, to ensure that they are in compliance with the laws and regulations of the SGX-ST, and are reasonable and in the best interests of the Company;
11. commissioning and reviewing the findings of internal investigations into matters where there is any suspected fraud or irregularity or failure of internal controls or infringements of any law, rule, regulation which has or is likely to have a material impact on the Company’s operating results and/or financial position;
12. review policy and arrangements by which the Company’s staff and any other persons may, in confidence, raise concerns about possible improprieties in matters of financial reporting or other matters and ensure that arrangements are in place for such concerns to be raised and independently investigated, and for appropriate follow-up action to be taken;
13. review insurance and other risk transfer arrangements;
14. review crisis management and business contingency planning processes and internal controls; and
15. perform any other acts as delegated by the Board and approved by the Audit and Risk Management Committee.

When reviewing the control systems particular note will be made of:

1. policies for preventing or detecting fraud;
2. operational effectiveness of the policies and compliance with the procedures related to risk and control; and
3. the Company’s code of ethics.

In the review of the half-year and annual financial statements and when making recommendations to the Board, the Committee will focus particularly on:

1. the quality and appropriateness of the accounting policies, practices and financial reporting disclosures and any changes thereto;
2. major estimate or judgmental areas/unusual transactions including, the assessed financial impact of health, safety, environmental and legal issues;
3. significant adjustments resulting from the external audit;
4. the going concern assumption including adherence to loan agreements and borrowing powers;
5. compliance with applicable accounting standards;
6. compliance with financial reporting standards, SGX-ST and legal requirements; and
7. any past misstatements and Managements’ response.

All decisions at any meeting of our ARMC shall be decided by a majority of votes of the members present and voting and such decision shall at all times exclude the vote, approval or recommendation of any member who is interested in the subject matter under consideration. Each member of our ARMC must abstain from voting on any resolution in respect of matters in which he is interested.

Apart from the duties listed above, the ARMC reviewed the Whistleblowing Policy by which people and representatives of the Company's group of companies, including employees, officers and contractors or their employees can report in good faith, matters or behaviours that they reasonably believe contravene, or may have contravened, Company policies, principles, values or the law. For the purposes of making a report under this Policy, matters may include any actual or suspected:

- improprieties in financial reporting;
- criminal activities;
- theft, fraud or misappropriation;
- serious harm to public health, safety or environment; or
- conduct or unethical behaviour which breaches any law (or may have a material impact on the Company's operating results or financial position).

Matters can be reported confidentially to:

- the Company Secretary;
- the Chairman;
- the CEO & Managing Director;
- the Company's audit partner; or
- a director of the Company if you feel the matter is so serious that it cannot be discussed with any of the listed parties or if any of the listed parties are involved in the matter.

The Whistleblower Policy can be found on the Company's website.

External Auditor

KPMG was appointed as auditor at the annual general meeting on 27 November 2008 and continues in office in accordance with section 327 of the *Corporations Act 2001*.

The external auditors have an unrestricted right to discuss any issues they deem necessary with the ARMC Chairman, or if deemed appropriate by the external auditors with the Chairman of the Board. The ARMC will require the external auditors to confirm, in writing, that they have complied with all professional and regulatory requirements relating to auditor independence prior to completion of each year's annual accounts.

Non-audit services

The Group may decide to employ the external auditor on assignments additional to their statutory audit duties where the auditor's expertise and experience with the Group is important. The Board of Directors has considered the non-audit services provided during the year by the auditor and in accordance with the written advice of the ARMC, is satisfied that the provision of those non-audit services during the year by the auditor is compatible with, and did not compromise, the auditor independence requirements of the *Corporations Act 2001* for the following reasons:

- All non-audit services were subject to the corporate governance procedures adopted by the Group and have been reviewed by the Audit and Risk Management Committee to ensure they do not impact the integrity and objectivity of the auditor; and

- the non-audit services provided do not undermine the general principles relating to auditor independence as set out in APES 110 Code of Ethics for Professional Accountants as they did not involve reviewing or auditing the auditor's own work, acting in a management or decision making capacity for the Company, acting as an advocate for the Group or jointly sharing risks and rewards.

The ARMC and Board of Directors confirm that in appointing the auditing firms for the Company and its subsidiaries, the Group has complied with SGX Mainboard Listing Rules 712 and Rule 715.

During the year the following fees were paid or payable for audit and non-audit services provided by the auditor of the Group, its related practices and non-related audit firms:

	2015 $
Audit services	
KPMG Australia	497,150
Overseas KPMG firms	726,776
	1,223,926
Services other than statutory audit	
KPMG Australia:	
Other services	23,000
	23,000

INTERNAL AUDIT

PRINCIPLE 13: *The Company should establish an effective internal audit function that is adequately resourced and independent of the activities it audits.*

The Company appointed Protiviti Pty Ltd in May 2014 to conduct a risk and control assessment focused on identification of key risks that could prevent the Company from achieving business objectives and an assessment of the design of the internal controls established by management. Risks covered included financial, operational, compliance and information technology controls. The assessment was based on discussions with management and key stakeholders, risk surveys and risk workshops to identify the key risks that impact or have the potential to impact the business.

Protiviti was adequately resourced with competent professionals and reported directly to the Chairman of the ARMC. The top ten risk events were presented to the ARMC for approval to use as the focus of an internal controls assessment. Interviews were held with the primary owner of each risk to understand the control environment, identify internal controls and design effectiveness evaluated. Potential gaps and improvement opportunities were identified and discussed with management and management action items developed.

This work has assisted the Board in determining the adequacy of internal controls, specifically financial, operational and compliance risk during the 2015 financial year.

The ARMC will at least annually review the adequacy and effectiveness of the internal audit function.

SHAREHOLDER RIGHTS AND RESPONSIBILITIES

SHAREHOLDER RIGHTS

PRINCIPLE 14: *Companies should treat all shareholders fairly and equitably, and should recognise, protect and facilitate the exercise of shareholders' rights, and continually review and update such governance arrangements.*

The Company is committed to treating all shareholders fairly and equitably. We recognise that shareholders should be entitled to equal information rights and we strive to provide sufficient information, in particular to changes and updates in our business which would be likely to have a material effect on the value of the Company's shares, in a timely manner.

We actively work with the Company's preferred brokers to ensure shareholders are able to participate in, and vote at, shareholder meetings. We provide shareholders with an explanatory statement on all resolutions at our shareholder meetings requiring a vote and we ensure that we do not bundle resolutions. The Company's practice is to electronically poll the votes on all resolutions and the results of the votes are known immediately and announced after close of trade on the day of the meeting.

The Company recognises that privacy is important and will not disclose registered shareholder details unless required by law. Shareholder details will only be used in accordance with applicable privacy laws.

COMMUNICATION WITH SHAREHOLDERS

PRINCIPLE 15: *Companies should devise an effective investor relations policy to regularly convey pertinent information to shareholders. In disclosing information, companies should be as descriptive, detailed and forthcoming as possible, and avoid boilerplate disclosures.*

The Company has a Shareholder Communications Policy that is built around compliance with disclosure obligations. The framework for communicating with shareholders is to concisely and accurately communicate:

- the Company's strategy;
- how the Company implements that strategy; and
- the financial results consequent upon that strategy and its implementation.

The Board seeks to inform shareholders of all major developments affecting the Company by:

- preparing annual financial reports;
- preparing quarterly financial statements and reports as to activities;
- making announcements in accordance with the listing rules and continuous disclosure obligations;
- hosting all of the abovementioned announcements on the Company's website;
- annually, and more regularly if required, holding a general meeting of shareholders and forwarding to our shareholders the annual report together with notice of meeting and proxy form; and
- voluntarily releasing other information which it believes is in the interest of shareholders.

The Company deals with shareholders enquiries promptly and courteously and takes measures to ensure that its registry agents, BoardRoom Australia and BoardRoom Singapore, also adhere to this level of service.

Continuous disclosure is fundamental to the rights of shareholders to receive information concerning their securities. Market announcements are posted on the Company's website immediately upon release to the market. Where the Company provides financial results briefings to analysts or media, these briefings are posted on the Company's website as soon as possible after the event. In any event, no material information which has not been previously released to the market is covered in such briefings. The material upon which the briefing is based is released to the market prior to the briefing.

General meetings are used to communicate with shareholders and allow a reasonable opportunity for informed shareholder participation. Shareholder meetings are an opportunity for shareholders and other guests to hear from and question the Board and Management of the Company. As part of these proceedings, a corporate update is presented to the forum either before or after voting on resolutions and general business.

As reflected in the Company's Constitution, subject to the Applicable Law, the Board may from time to time either determine or declare that a dividend is payable to the shareholders and fix the amount of the dividend, the time for payment and the method of payment.

The Company's Shareholder Communications Policy is available on the Company's website.

CONDUCT OF SHAREHOLDER MEETINGS

PRINCIPLE 16: *Companies should encourage greater shareholder participation at general meetings of shareholders, and allow shareholders the opportunity to communicate their views on various matters affecting the company.*

General meetings are used to communicate with shareholders and allow a reasonable opportunity for informed shareholder participation. Shareholder meetings are an opportunity for shareholders and other guests to hear from and question the Board and Management of the Company. As part of these proceedings, a corporate update is presented to the forum either before or after voting on resolutions and general business. The Company ensures that the company presentation is released to the market and is available on the Company's website. In addition, minutes of general meetings are taken and available to shareholders upon request. The chair of the meeting, usually the Chairman, is responsible for the conduct of the meeting.

All directors and executives attend shareholder meetings and are available to answer any questions regarding the conduct of and any issues arising from the Company's audit and other business related matters.

The Company's external auditors are available at the annual general meeting to answer questions in relation to:

- the conduct of the audit;

- the preparation and content of the auditor's report;
- the accounting policies adopted by the Company in relation to the preparation of the annual financial statements; and
- the independence of the auditors.

The Company strives to ensure a broad range of participants may actively be involved in the conduct of its shareholder meetings without attending in person. The Company accepts nominations for the Board of the Company that are made to the Company Secretary in accordance with the listing rules and the Company's Constitution. The Company conducts all shareholder meetings in accordance with the regulatory requirements and its Constitution.

In accordance with the Company's Constitution, shareholder meetings are conducted by instantaneous audio-visual communication between Brisbane and Singapore by which members as a whole are given a reasonable opportunity to participate. All members entitled to vote on an item of business at the Meeting are able to do so at either venue.

The Company drafts notices and proxy forms to maximise the ability of readers to understand and vote on the issues presented. The Company introduced electronic polling in dual venues at its Extraordinary General Meeting on 14 May 2015 and will again implement this process at its Annual General Meeting on 29 October 2015. This ensures all results are instantaneous and available to shareholders.

SECURITIES TRADING POLICY

The Company has a formal Securities Trading Policy with respect to dealings in the securities of the Company by its directors, officers and employees in compliance with SGX Mainboard Listing Rule 1207 (19) of the Listing Manual. The Group's officers and employees are restricted from dealing in the Company's securities when in possession of price sensitive information that relates to the financial affairs of the Company, which may give the person proposing to deal in the securities an advantage over other persons holding the securities and which if it were generally available would likely materially affect the value of the securities.

Key requirements of the policy for officers and key management personnel state they:

- are not permitted to engage in short term trading of the Company's securities; and
- are prohibited from trading in financial products issues or created over or in respect of the Company's securities.

They shall not trade in the Company's securities during the following periods:

- in the 14 day period preceding the announcement of the Company's financial statements for each of the first three quarters of the financial year;
- in the 30 day period preceding the announcement of the Company's results for the full financial year or half-year financial results; or
- at any other time when the person is in possession of price sensitive information or where the Company determines it is considering matters which are subject to SGX Listing Rules.

The Company's Securities Trading Policy is available on the Company's website.

MATERIAL CONTRACTS

Pursuant to SGX Mainboard Listing Rule 1207 (8) the Company confirms there were no material contracts entered into by the Company or its subsidiaries, involving the interests of the CEO, directors or controlling shareholders, either still subsisting at the end of the financial year or, if not subsisting, entered into since the end of the previous financial year.

DIRECTORS' REPORT

The Directors present their report on the consolidated entity (referred to hereafter as the Group) consisting of Linc Energy Ltd (the Company) and the entities it controlled at the end of, or during, the year ended 30 June 2015.

DIRECTORS

Unless otherwise stated, the following persons were Directors of the Company during the whole of the financial year and up to the date of this report:

Name, qualifications and independence status	Experience and special responsibilities
Mr Peter Bond Executive Chairman	Appointed Executive Chairman 1 October 2014 Chief Executive Officer and Managing Director until 1 October 2014 Executive Director since October 2004
Mr Craig Ricato CEO and Managing Director, Executive Director	Executive Director since October 2010 Non-Executive Director from 1 July 2013 to 30 September 2014 Member of the Audit and Risk Management Committee until 1 October 2014 Appointed CEO and Managing Director and Chief Executive Officer on 1 October 2014
Mr Lim Ah Doo – resigned 23 June 2015 Lead Independent Non-Executive Director	Chairman of the Audit and Risk Management Committee Member of Nominating Committee Non-Executive Director since 22 November 2013
Mr Kenneth Dark Independent Non-Executive Director	Member of Remuneration Committee until 30 June 2015 Member of Nominating Committee until 30 June 2015 Interim Chairman of Nominating and Remuneration Committee from 1 July 2015 Non-Executive Director since October 2004 Appointed Chairman on 12 October 2012 and resigned 1 October 2014
Mr Jon Mathews – resigned 31 July 2015 Independent Non-Executive Director	Chairman of the Remuneration Committee to 30 June 2015 Member of the Nominating and Remuneration Committee from 1 July 2015 Member of the Audit and Risk Management Committee Non-Executive Director since December 2009
Mr Koh Ban Heng – resigned 22 May 2015 Independent Non-Executive Director	Chairman of Nominating Committee Member of Remuneration Committee Director since 22 November 2013
Mr Ong Tiong Soon Non-Executive Director	Appointed Non-Executive Director 28 May 2015

Following the departures of Mr Koh Ban Heng and Mr Lim Ah Doo, the Company was not compliant with Singapore Mainboard Listing Rule 210 (5) (c) and Rule 221 as the Company did not have two independent directors resident in Singapore. The Company has rectified this with the appointment of Mr Mark Leahy and Mr James (Mun Foong) Yip as Independent Non-Executive Directors on 3 August 2015.

Other Directors information

Director	Other current public company directorships	Former public company directorships in the last 3 years
Mr Peter Bond	European-Australian Business Council Ltd	None
Mr Craig Ricato	Pan Terra Gold Ltd	None
Mr Lim Ah Doo	GP Industries Ltd ARA-CWT Trust Management Ltd Trustee Manager of Cache Logistics Trust Sateri Holdings Ltd Sembcorp Marine Ltd SM Investments Corporation U Mobile Sdn Berhad	Chemoil Energy Ltd
Mr Kenneth Dark	None	None
Mr Jon Mathews	None	None
Mr Koh Ban Heng	Tipco Ashpalt PLC of Thailand Chung Cheng High School Ltd	Singapore Petroleum Company Ltd
Mr Ong Tiong Soon	Genting Oil and Gas Limited Genting Power China Limited Genting Sanyen (Malaysia) Sdn Bhd Genting Biofuels Sdn Bhd Genting Synergy Limited Oxalis Limited Lanco Kondapalli Power Limited Lion Agriculture (Indonesia) Sdn Bhd Lanco Tanjore Power Company Limited	Genring Oil & Gas (China) Limited Genting Sanyen Power Sdn Bhd Alternate Director) Mastika Water Management Sdn Bhd Fujian Pacific Electric Company Limited Highlands Exploration Limited Highlands Power Development Limited

COMPANY SECRETARY

Ms Janelle van de Velde was appointed Company Secretary on 1 January 2015 following Mr Brook Burke's resignation. Ms van de Velde has over 25 years of experience working for publicly-listed companies.

She joined the Company in August 2006 and in this time has held many diverse roles including investor relations, corporate communications and stakeholder relations.

In the role of Chief Administrative Officer and Company Secretary, Ms van de Velde is responsible for delivering a global communications strategy, incorporating corporate communications, media, stakeholder and government relations activities globally, while also administering the affairs of the Company and Business of the Board, including the Company's adherence to its corporate governance policies. Janelle is also responsible for ensuring the required business services such as IT, telecommunications, travel and administration support the Company's requirements.

PRINCIPAL ACTIVITIES

The principal continuing activities of the Group consisted of:

- Conventional oil and gas exploration and production; and
- Unconventional oil and gas focused on the commercialisation of our proprietary technology in Underground Coal Gasification (UCG), the process of converting coal into a valuable synthetic gas in situ.

Linc Energy has constructed and commissioned a UCG to Gas to Liquid (GTL) demonstration facility. The Company also owns and operates a commercial UCG operation in Uzbekistan, which supplies syngas to a nearby power station.

In February 2015, the Group announced the sale of its conventional coal business, New Emerald Coal Ltd (NEC), a separate reportable segment (see note 7) to United Queensland Resources Pty Limited, a part of United Mining Group which included the agreements to acquire the Blair Athol Coal Mine from Blair Athol Joint Venture, the Teresa development project including its Gladstone port capacity, the Pentland and Dalby development projects and the Company's Queensland greenfield exploration tenure. The Company will continue to share in the benefits of these projects as they reach production through the Revenue Sharing agreement with NEC. The sale was approved at an Extraordinary General Meeting held on 14 May 2015.

The Group has also begun low cost early stage development work regarding the adaption of its proprietary UCG downhole tools and techniques for the extraction of heavy crude oil.

OPERATING REVIEW

Information on the operations of the Group and its business strategies and prospects is set out in the Review of Operations and Activities on pages 9 to 25 of this Annual Report.

FINANCIAL REVIEW

Revenues

Total Group revenues for the financial year ended 30 June 2015 have decreased by $60,604,000 from $148,390,000 to $87,786,000 predominately due to decreased oil and gas net sales in the US.

Oil and gas sales in the US have decreased by 42.2% from $141,627,000 (USD$130,000,000) to $81,810,000 (USD$68,467,000) which is a result of reduced production of 876 BOEPD and decrease in overall realised price per barrel of USD$29.94.

The average oil and gas sales price achieved for the year was USD$69.37 (2014: USD$102.15) per barrel after hedging, USD$3.09 (2014: USD$3.59) per Mcf of natural gas and USD$1.23 (2014: no liquids) per gallon of liquids for an overall average of USD$67.25 (2014: USD$92.14) per barrel. The Group continued to hedge a portion of production to help minimise the impact of falling oil prices in the current environment. The Group holds West Texas Intermediate (WTI) swaps to cover 28% of forecasted production at a price of USD$86.22 per barrel for the remainder of the 2015 calendar year. Additional put options were executed in April 2015 at USD$55 per barrel for 250 BOPD until 31 December 2015 which will cover an additional 9% of production until the end of the calendar year. Further details on the Group's oil hedges are included in note 26 to the financial statements.

A summary of the Group's oil sales is below:

Oil sales (Linc net interest)

Area	Year ended 30 June 2015 Total Barrels	Year ended 30 June 2014 Total Barrels	Year ended 30 June 2015 Average BOEPD	Year ended 30 June 2014 Average BOEPD
Gulf Coast	970,994	1,287,419	2,660	3,528
Wyoming	47,072	50,138	129	137
Total	1,018,067	1,337,557	2,789	3,665

The Group experienced a slight increase in revenue this financial year from syngas sales in Uzbekistan of $421,000 from $2,637,000 to $3,058,000 but revenue generated from UCG consulting agreements has fallen by $1,046,000 from $1,670,000 to $624,000. The Company is continuing to seek out UCG opportunities around the world. Further details on the Clean Energy's activities for the financial year can be found in the Review of Operations on pages 9 to 25.

This financial year, $2,294,000 has been released for Exxaro intellectual property deferred revenue. (2014: $2,456,000). This revenue continues to be recognised on a monthly basis over the expected period that the services are provided.

Cost of sales

Cost of sales have increased by $12,770,000 from $112,379,000 to $125,149,000 primarily due to an increase of $12,462,000 in depletion expense on US oil and gas wells.

Sale of royalty

The Group has recognised $148,611,000 for the sale of the Carmichael (Adani) royalty. On 27 August 2014 the Company entered into a Put and Call Option Deed with the Adani Group, to sell the Carmichael (Adani) Royalty Deed. Upon exercise of the Put or Call Option, the Company transferred all of its rights, interests, benefits and obligations of the Carmichael Royalty Deed to the Adani Group for a total consideration of $155,000,000.

Under the agreement the Company received two tranches. The first tranche of $90,000,000 was received within five days of exercise and the second tranche of $65,000,000 was to be received on or before the expiry of twelve months from the date of exercise. As the second tranche was to be received outside of the Company's normal credit terms, it was measured at Fair Value and discounted to the Present Value. The Present Value was discounted to $58,611,000; therefore the total revenue recognised for the period was $148,611,000.

Gain on sale of available-for-sale assets

During the year, the Group sold shares in one of its listed equity investments. A gain of $433,000 has been recognised which represents the difference between the fair value and sale proceeds and a transfer of equity being held in the available-for-sale reserve.

Operating expenses from continuing operations

Total administration and corporate expenses for the year have decreased by $18,212,000 from $78,480,000 to $60,268,000 in line with cost control initiatives implemented throughout the financial year. Employee benefits expenses have decreased by $7,462,000 and share based payment expense decreased by $5,863,000.

Site operating costs have decreased by $1,660,000 from $6,875,000 to $5,215,000 due to reduced level of operation and employee numbers at the Chinchilla demonstration facility.

During the year there has also been a decrease of $852,000 for exploration and evaluation expenses and $806,000 for technology development expenses in line with cost control initiatives.

A net foreign exchange gain of $8,715,000 has been recognised, which is a $12,071,000 increase from the prior financial year (2014: loss of $3,356,000). This is primarily a result of unrealised foreign exchange movements on intercompany loans of subsidiaries held in a different functional currency and unrealised foreign exchange gain on foreign cash held in Australian bank accounts. During the financial year this has been driven by an 18c movement in AUD/USD exchange rates (30 June 2014: 0.9419 to 30 June 2015: 0.7655).

Other expenses have increased by $143,978,000 from $39,859,000 to $183,837,000 mainly due to an impairment expense of $173,351,000 (2014: $34,390,000) being recognised during the year on US oil and gas assets. For further details refer to note 4.

During the year the Group has recognised a net gain of $75,000 for the discount on sale of receivable. The Group was reimbursed $211,000 (USD$188,000) from the purchaser of the oil and gas production tax credits pursuant to Alaska Statute 43.55.023. The reimbursements were due to the repayment of disallowed credits.

On 23 December 2014, the Group reimbursed $136,000 (USD$110,000) to one of its non-controlling interest partners their portion of the oil and gas production tax credits.

Finance income, finance expenses and financial Instruments expenses

Finance income has increased by $2,719,000 from $1,223,000 to $3,942,000. This is mainly due to the recognition of the present value discount on the sale of the second tranche of the Carmichael (Adani) royalty being recognised as an interest income charge each month as the settlement terms for the second tranche were outside the normal credit terms for similar sale transactions of royalties.

Finance expenses have increased by $22,851,000 from $69,306,000 to $92,157,000 mainly due to increased levels of debt and unfavourable exchange rate movements on the $USD denominated interest payments/accruals for the Second Lien Senior Secured Notes, First Lien Senior Secured Notes and Convertible Notes. Finance expenses associated with the Receivable Factoring Facility Agreement for the second tranche of the Carmichael (Adani) Receivable ($5,361,000) have also been recorded during the period.

Financial instruments expenses have decreased by $6,312,000 from $30,471,000 to $24,159,000 primarily as a result of gains on US oil commodity swaps ($42,766,000). However, these have been offset by a net loss of $37,412,000 in movements for the convertible notes year on year. For further details refer to note 6.

Discontinued operation

During the year, the Group classified its Coal segment as a discontinued operation as Management committed to a plan to sell the coal segment. The Coal segment was not previously classified as held-for-sale or as a discontinued operation therefore the comparative consolidated statement of profit or loss and other comprehensive income has been restated to show the discontinued operation separately from continuing operations.

On 14 February 2015, the Company entered into an arrangement to sell its conventional coal business, New Emerald Coal Ltd (NEC), to United Queensland Resources Pty Limited (United), a part of United Mining Group which included the agreements to acquire the Blair Athol Coal Mine from Blair Athol Joint Venture, the Teresa development project including its Gladstone port capacity, the Pentland and Dalby development projects and Linc Energy's Queensland greenfield exploration tenure.

The sale of the conventional coal business was subject to shareholders' approval at the Extraordinary General Meeting held on 14 May 2015 and was concluded 21 May 2015.

On 21 May 2015, the Company elected to convert amounts payable by United, under the Share Sale Agreement into a loan. The total amount advanced to United under the Loan Agreement upon completion was $7,179,000. This includes $6,000,000 for the sale of NEC and $1,179,000 for amounts advanced to United. Interest is payable on the amount outstanding monthly in arrears at 12.5% per annum. The loan is repayable on or before 21 May 2017, unless the Loan Agreement is terminated earlier in accordance with its terms and is recognised as a non-current receivable in the statement of financial position.

In the statement of profit or loss and other comprehensive income, a loss from discontinued operation, net of tax of ($43,882,000) has been recognised. For further details refer to note 7.

Financial Position

Current assets of the Group have decreased by $11,617,000 during the twelve month period from 30 June 2014 as a result of:

- Cash and cash equivalents decreased by $25,506,000 (refer to statement of cash flows for a breakdown of movements);
- Trade and other receivables have decreased by $6,535,000 predominantly due to the reduction in US oil and gas accrued well revenues ($4,812,000), which was driven by lower production and oil prices;
- Inventories have increased by $728,000;
- Assets classified as held-for-sale have increased by $11,706,000 due to the favourable movement in the share price of the listed investment; and
- Other financial assets increased by $7,990,000 indicating positive movement of hedge position due to the decline in current oil prices (reported as other financial liabilities in prior periods).

Non-current assets of the Group have decreased by $120,045,000 predominantly due to:

- Oil and gas assets decreased by $118,945,000. This is comprised of capital additions of $39,229,000, depletion/depreciation of $85,564,000, impairment of $169,472,000, a favourable movement in foreign exchange rates of $97,518,000 and Asset Retirement Obligation (ARO) movements and disposals of $656,000; and
- Intangibles have decreased by $14,486,000 predominantly due to the disposal of assets relating to the coal segment sale (refer to note 7 Discontinued Operations for further analysis).

Current liabilities of the Group have decreased by $52,108,000 predominantly due to:

- Trade and other payables have decreased by $22,731,000 due to continued efforts to pay down outstanding creditors in the USA;
- Borrowings have decreased by $23,295,000 primarily due to movements within the Convertible Notes, including the redemption of USD$50,000,000 notes for $61,794,000, conversion of USD$16,700,000 notes into shares by Note holders for $21,169,000 and unfavourable movements in exchange rates and the modification of notes in December 2014 (refer to note 19 for further details);
- Deferred revenue has decreased by $1,211,000, due to the release of the Exxaro intellectual property revenue; and
- Due to the positive movement in the Group's US unrealised hedging profile, other financial liabilities have reduced by $5,766,000 and are now classified as other financial assets.

At 30 June 2015 the Group had a net current liability position of $155,953,000 due to the reclassification of the Convertible Notes from non-current to current liabilities. Although the Company is in the process of exploring various options with the Note holders to rectify this position, the redemption option date of 10 April 2016 is within 12 months of the reporting date and thus in accordance with International Financial Reporting Standards and Australian Accounting Standards the Notes must be classified as a current liability.

Non-current liabilities have increased by $156,981,000 predominately due to:

- Borrowings have increased by $146,516,000 primarily as a result of the following movements:
  - Decrease of $73,105,000 relating to the Key Bank Reserve Based Lending Facility which has been repaid and closed;
  - Increase of $152,744,000 from the issue of First Lien Senior Secured Notes in August 2014 which includes proceeds of $134,931,000, bond fees of $11,436,000 and the balance is movement in foreign exchange rates and amortisation of fees;
  - Increase of $67,513,000 in Second Lien Senior Secured Notes mainly due to unfavourable movements in AUD/USD exchange rate since 30 June 2014;
- Provisions have increased by $14,216,000 primarily due to an increase in the US oil and gas assets rehabilitation obligations; and
- Due to the positive movement in our US unrealised hedging profile, other financial liabilities have reduced by $2,785,000 and are now classified as other financial assets.

Statement of Cash Flows

Net cash outflows from operating activities of $77,959,000 were comprised of:

- Receipts from customers of $94,412,000 of which $88,259,000 was from US oil and gas sales, $4,099,000 from syngas sales in Uzbekistan and clean energy consulting and miscellaneous cash receipts of $2,054,000;
- Payments to suppliers and employees of $110,880,000 comprising of $32,666,000 in US and Uzbekistan production costs and $78,214,000 in working capital;
- Net receipts for US oil commodity swaps of $7,141,000; and
- Interest and borrowing costs paid of $68,632,000 which was predominately comprised of interest paid on US First and Second Lien Senior Secured Notes of $51,288,000 and interest paid on US Convertible Notes of $15,460,000.

Net cash inflows from investing activities of $49,730,000 were predominately comprised of:

- Payments for exploration intangibles of $19,015,000 predominately for exploration activities in the Arckaringa basin in Australia;
- Payments for exploration and development of oil and gas assets of $77,216,000 of which $21,676,000 was spent on Umiat (on going supplier payments for the winter drilling program in 2014) and $55,540,000 spent in the Gulf Coast;

- Proceeds of $90,000,000 from the first tranche of the sale of the Carmichael (Adani) royalty; and
- Net funds received of $56,444,000 from the receivable factoring deal for the second tranche of the Carmichael (Adani) royalty.

Net cash outflows from financing activities of $14,786,000 were predominately comprised of:

- Proceeds of $134,931,000 from the First Lien Senior Secured Notes issue of which $74,581,000 was utilised to repay the outstanding principal and close the Key Bank Reserve Based Lending Facility. Net movement on the facility for the year was $74,332,000 as there was also a draw down in July 2014 of $249,000;
- Redemption of USD$50,000,000 in Convertible Notes for $61,794,000; and
- Payments associated with financing activities of $13,037,000 predominately related to the issue of the First Lien Senior Secured Notes.

Cash of $6,000 was disposed during the year with the discontinued operation.

Shareholder returns

	2015	2014	2013	2012	2011
Profit/(loss) attributable to equity holders of Linc Energy Ltd	($292,832,000)	($227,180,000)	($63,805,000)	($61,891,000)	$296,455,000
Basic EPS	(49.19) cents	(41.21) cents	(12.40) cents	(12.18) cents	59.27 cents
Diluted EPS	(49.19) cents	(41.21) cents	(12.40) cents	(12.18) cents	57.71 cents
Dividends paid	-	-	-	-	$49,643,000
Dividends per share	-	-	-	-	10.0 cents

Use of proceeds

	Amount $'000 SGD	Amount $'000 AUD
IPO Funds raised	62,220	55,499
Less underwriting commissions	(3,462)	(3,089)
Net IPO proceeds	**58,758**	**52,410**
	IPO Funds Raised AUD[1]	Utilised to date AUD
Actual use of proceeds to 30 June 2015:		
Conventional Oil & Gas (Umiat Development)	18,315	18,315
Unconventional Oil & Gas (Clean Energy / SAPEX)	22,477	20,437
Working Capital & General Corporate Expenses[2]	5,550	5,550
Expenses in connection with Offering	9,157	9,157
Total use of IPO proceeds to 30 June 2015	55,499	53,459

[1] As disclosed in the IPO prospectus.

[2] Working capital funds have been used primarily for the payments of salaries and office overheads.

As at 30 June 2015, the actual use of proceeds are in accordance with the stated use outlined in the IPO prospectus. The Company has not utilised AUD$2,040,000 of IPO funds as at this date.

Exploration, development and/or production

Pursuant to SGX Mainboard Listing Rule 705(7) (a), the following table shows the total cash spent on exploration (including geophysical surveys), development and/or production activities undertaken during the financial year ended 30 June 2015.

Purpose	Amount $'000 AUD
US oil and gas development	77,216
US and Uzbekistan production costs	32,666
US Umiat exploration[1]	21,676
Australian exploration drilling program	18,532
Exploration	483

[1] Cash payments for US Umiat exploration relate to the previous winter drilling program in 2014. No exploration activities have been undertaken in the current financial year.

Refer to Review of Operations and Activities section commencing on page 9 to 25 for detailed information on exploration, development and productions activities during the financial year.

Significant changes in the state of affairs

Significant changes in the state of affairs of the Group during the year were as follows:

- *Sale of conventional coal business* - On 16 February 2015, the Company announced it had entered into an arrangement to sell its conventional coal business, New Emerald Coal Ltd (NEC), to United Queensland Resources Pty Limited (United), a part of the United Mining Group which included the agreements to acquire the Blair Athol Coal Mine from Blair Athol Joint Venture, the Teresa development project including its Gladstone port capacity, the Pentland and Dalby development projects and Linc Energy's Queensland greenfield exploration tenure. The Company will continue to share in the benefits of these projects as they reach production through the Revenue Sharing agreement between Linc Energy and NEC. The agreement provides for consideration of $6,000,000 as well as an indexed royalty per product tonne of coal from the potential Blair Athol mine (USD$0.50), Teresa (USD$1.00) and Pentland (USD$1.00) projects. The sale of the conventional coal business was subject to shareholders' approval at the Extraordinary General Meeting held on 14 May 2015.

- *Loan to United Queensland Resources Pty Limited* - On 21 May 2015, the Company elected to convert amounts payable by United Queensland Resources Pty Limited (United), under the Share Sale Agreement into a loan. The total amount advanced to United under the Loan Agreement upon completion was $7,179,000. This includes $6,000,000 for the sale of NEC and $1,179,000 for amounts advanced to United. Interest is payable on the amount outstanding monthly in arrears at 12.5% per annum. The loan is repayable on or before 21 May 2017, unless the Loan Agreement is terminated earlier in accordance with its terms.

- *Amendment to Convertible Notes* - On 30 December 2014, formal approval was reached with the Note holders to amend the terms of the Company's USD$200,000,000 7% Convertible Notes (Notes) due 2018. The key terms of the agreement included a USD$50,000,000 repayment to reduce the principal amount of outstanding Notes from USD$200,000,000 to USD$150,000,000, the existing Note holders put option to move from 10 April 2015 to 10 April 2016, a call option will be exercisable by the Company up to 10 April 2016, updated conversion price of SGD$1.3411 and the interest rate to increase from 7% to 9% from 11 April 2015. On 10 April 2015, the conversion price was reset to a conversion price of SGD$0.77. Refer to note 19 for further details.

- *Conversion of Convertible Notes* – On 4 May 2015, the Company issued 8,446,102 shares on conversion of USD$5,000,000 of the Company's USD$200,000,000 Convertible Notes at SGD$0.77 per share.

  On 21 May 2015, the Company issued a further 19,763,881 shares on conversion of USD$11,700,000 Convertible Notes at SGD$0.77 per share. The balance of the Company's Convertible Notes are now USD$133,300,000.

  Refer to note 34 for further details on the voidance of some of these shares due to a calculation error by the Trustee.

- *Sale of Adani (Carmichael) Royalty* - On 27 August 2014, the Company entered into a binding Put and Call Option Deed in relation to the Carmichael Royalty with the Adani Group. On 10 October 2014, the Adani Group exercised their call option under the Put and Call Option Deed for the transfer of the Company's interest in the Carmichael Royalty Deed to the Adani Group. The option exercise consideration was $155,000,000 with the first tranche of $90,000,000 being received on 13 October 2014. The second tranche of $65,000,000 was due on 9 October 2015.
- *Receivable Factoring Facility for Second tranche of Adani Royalty sale* - On 31 March 2015, the Company entered into a Receivable Factoring Facility Agreement (RFFA) with a third party Financial Institution (FI) in relation to the second tranche of monies due from certain subsidiaries of the Adani Group (Adani) on 9 October 2015 (Adani Receivable). Cash from the transaction was received on 2 April 2015.

  Under the RFFA, the Company agreed to assign its rights to receive the $65,000,000 under the Put and Call Option Deed agreed with Adani dated 27 August 2014 to the FI. The cost of the transaction to the Company, when compared to the discounted present value of the future Adani Receivable was $5,361,000 which included a commitment fee of $825,000 payable upon Financial Close of the RFFA.
- *First Lien Senior Secured Notes* - On 13 August 2014, the Company successfully completed the issuance of a new USD$125,000,000 First Lien Senior Secured Note facility which was used to repay the existing Key Bank Reserve Based Lending facility and provide an improved working capital position in its US oil and gas business. Refer to note 19 for further details.
- *Restructure of Second Lien Senior Secured Notes* – On 29 May 2015, the Company announced majority consent had been obtained to amend the terms of the USD$265,000,000 12.5% Second Lien Senior Secured Notes Due 2017 as follows:
  - an option for the Company to capitalise the coupon payments due on the Notes in October 2015;
  - an option to capitalise the coupon payments due on the Notes in April 2016 upon the Company's oil and gas subsidiary, Linc Energy Resources Inc., receiving net cash proceeds of one or more equity offerings in the aggregate amount of at least USD$50,000,000;
  - if the Company elects to capitalise one or both of these coupon payments, the coupon will be calculated at 14%. If the Company elects to cash settle the coupon payments, the coupon will be calculated at the current 12.5% rate; and
  - upon the sale of any material assets of the Company's oil and gas subsidiary, Linc Energy Resources Inc, the proceeds will be used to pay down US secured debt in order of priority at the respective call prices contained within the indenture documents at the time of sale.

Dividends

No dividends were paid or declared by the Company during the year or up to the date of this report.

Matters subsequent to the end of the financial year

Cessation of Independent Non-Executive Director

On 31 July 2015, Independent Non-Executive Director, Mr Jon Mathews resigned to commence his retirement.

Appointment of Independent Non-Executive Directors

On 3 August 2015, the Company appointed two Independent Non-Executive Directors, Mr Mark Leahy and Mr James (Mun Foong) Yip. Mr Mark Leahy has been appointed Lead Independent Director, Chairman of the Audit and Risk Management Committee and member of the Nominating and Remuneration Committee. Mr James (Mun Foong) Yip has been appointed Chairman of the Nominating and Remuneration Committee and member of the Audit and Risk Management Committee.

Issued Capital

On 6 August 2015, the Company voided the issuance of a total of 7,052,497 shares that were issued in error on 21 May 2015 and 4 May 2015 as part of the conversion of USD$16,700,000 face amount of the Company's USD$200,000,000 7% Convertible Notes due 2018. The extra shares were issued as a result of a calculation error in the Conversion Notice sent to the Company by the Trustee (Citicorp International Limited) in May 2015, relating to the manner in which the USD$50,000,000 redemption in January 2015 was implemented. Following the voidance of shares, the number of issued and paid-up shares in the capital of the Company has decreased to 615,966,776 equating to $425,545,587 while the Convertible Notes have a carrying value of USD$137,475,000. The effect on earnings per share would have been as follows:

	Current	Revised
Profit / (loss) attributable to the ordinary equity holders of the Company:		
Basic earnings / (loss) per ordinary share (AUD cents per share)	(49.19)	(49.26)
- weighted average number of shares	595,302,273	594,411,730
Fully diluted earnings / (loss) per ordinary share (AUD cents per share)	(49.19)	(49.26)
- weighted average number of shares	595,302,273	594,411,730

Likely developments

Comments on likely developments and expected results of operations of the Group are included in this Annual Report under the Review of Operations and Activities section on pages 9 to 25. Further information on likely developments in the operations of the Group and the expected results of operations have not been included in this Annual Report because the Directors believe it would be likely to result in unreasonable prejudice to the Group.

Environmental regulation

The Group is subject to statutory environmental requirements in various jurisdictions in which it operates in relation to exploration, UCG, GTL and oil and gas production.

In relation to Australian law and in the reporting period, the Group complied with its environmental obligations. There were no instances of non-compliance that the Group considered to be material in nature.

In Queensland, the Group must comply with environmental legislation for exploration and UCG activities. The *Environmental Protection Act* regulates the environmental performance of the Group when conducting environmentally relevant activities (which include exploration, mining by UCG and gas processing). The Group has environmental licences issued for exploration tenements and the Chinchilla Demonstration Facility. The Group considers that at no point has it operated materially outside the requirements of its environmental permits.

In April 2014, the Company was served with a Complaint and Summons by the Queensland Department of Environment and Heritage Protection (DEHP) charging the Company with four indictable offences alleging the Company wilfully and unlawfully caused serious environmental harm during the operation of its UCG Demonstration Facility at Chinchilla on a date or dates unknown between July 2007 and February 2012, being the operation of gasifiers 2, 3 and 4, in breach of the Environmental Protection Act 1994 (EP Act). The Company considers these allegations to be without merit, although there can be no assurance that the Company will not be found guilty of the offences.

In January 2015, DEHP amended the four charges to remove the allegation the Company intentionally caused the alleged serious environmental harm.

In June 2015, DEHP served a further Complaint and Summons charging the Company with a fifth indictable offence alleging the Company wilfully and unlawfully caused serious environmental harm during the operation of its UCG Demonstration Facility at Chinchilla on a date or dates unknown between October 2011 and December 2013, being the operation of gasifier 5.

The maximum aggregate financial penalty under the EP Act for the 5 indictable offences for a corporation is approximately $18,406,250 ($3,681,250 per offence). The Company is confident of defending itself against these charges. In the event the Company is unsuccessful and was to be found guilty of all 5 charges, the Company may have to pay a nominal fine, undertake some form of rehabilitation and engage in regular compliance monitoring and reporting to DEHP, which should not have a material impact on the Company's operations.

During the year ended 30 June 2015, the Company also received a decision on the application to amend or discharge the financial assurance bond required to be held with the DEHP in relation to MDL's and PFL's in Chinchilla. This decision requires the bond to be increased from $3,900,000 to $29,200,000. While this decision accepts a number of the Company's assertions in relation to the costs associated with rehabilitation, the main differences relate to methodology of and costs associated with processing water and impacted soil. The Company believes that the methodology applied in calculating the rehabilitation costs is consistent with relevant regulations and it intends to apply this methodology in the rectification of the MDL's and PFL's. The Company has applied for stay of the decision with the DEHP which has been ratified. The Company is therefore not required to provide any increased financial assurance until the litigation appeal with the Lands Court is finalised.

In South Australia, the Group's exploration activities are controlled through the petroleum legislation. The Group has approved Statements of Environmental Objectives (SEO's) and Environmental Impact Reports (EIR's) for exploration in the Arckaringa, Walloway and Cooper Basins.

In the US the Group has been actively engaged in exploration for UCG prospects in the State of Alaska and characterisation in the State of Wyoming. The drilling is conducted under all appropriate and required permits secured from State and Federal agencies.

The Group operates an oilfield in Wyoming under approvals from the Wyoming Oil and Gas Conservation Commission, oilfields in Texas under approvals from the Texas Commission on Environmental Quality and the Railroad Commission of Texas and in Louisiana with approvals from the Louisiana Department of Natural Resources and Office of Conservation.

Other than as specified above, the Group was not subjected to any enforcement actions during the reporting period.

Further comments on the Group's environmental management activities can be found in the Review of Operations and Activities commencing on page 9.

Directors' interests as at 21 July 2015

Pursuant to SGX Mainboard Listing Rule 1207 (7), the relevant direct and deemed interests of each director in the shares and rights over such instruments issued by the Company as at 21 July 2015 are as follows:

Name	Ordinary shares Direct	Ordinary shares Deemed
Mr Peter Bond	-	202,626,940
Mr Craig Ricato	1,000,561	-
Mr Kenneth Dark	-	1,290,000
Mr Jon Mathews	500,000	3,000
Mr Ong Tiong Soon	-	136,000

Share options

No options have been granted in the financial year ended 30 June 2015. All options granted in previous financial years have lapsed. The Employee Option Plan is no longer operational.

Performance rights

No performance rights remain outstanding at 30 June 2015. The Employee Performance Rights Plan is no longer operational.

Insurance and indemnification of officers

Linc Energy Ltd has obtained Directors and Officers Liability Insurance. The Directors have not included details of the nature of the liabilities covered or the amount of the premium paid in respect of the directors' and officers' liability and legal expenses insurance cover, as such disclosure is prohibited under the terms of the contract.

The Company has agreed to indemnify the following current directors of the Company, Mr Craig Ricato, Mr Peter Bond, Mr Kenneth Dark, Mr Mark Leahy, Mr James (Mun Foong) Yip, Mr Ong Tiong Soon and former directors Mr Koh Ban Heng, Mr Lim Ah Doo and Mr Jon Mathews against all liabilities to another person (other than the Company or a related body corporate) that may arise from their position as directors of the company and its controlled entities, except where the liability arises out of conduct involving a lack of good faith. The agreement stipulates that the Company will meet the full amount of any such liabilities, including costs and expenses.

The Company has agreed to indemnify certain senior executives for all liabilities to another person (other than the Company or a related body corporate) that may arise from their position in the Company and its controlled entities, except where the liability arises out of conduct involving a lack of good faith. The senior executives in question are the Company Secretary, Ms Janelle van de Velde and former Company Secretary, Mr Brooke Burke, Chief Operating Officer, Mr Michael Mapp and Chief Financial Officer, Mr Chris Munday and former Chief Financial Officer, Mr Stuart Jones. The agreement stipulates that the Company will meet the full amount of any such liabilities, including legal fees.

Lead auditor's independence declaration

The Lead auditor's independence declaration as required under section 307C of the *Corporations Act 2001* is set out on page 65 and forms part of the Directors' Report.

Rounding of amounts

The Group is of a kind referred to in Class Order 98/100 dated 10 July 1998 issued by the Australian Securities and Investments Commission and in accordance with the Class Order, amounts in the consolidated financial statements and director's report have been rounded off to the nearest thousand dollars, unless otherwise stated.

Statement by Directors

We, Craig Ricato and Peter Bond, being two Directors of Linc Energy Ltd (the "Company"), do hereby confirm on behalf of the Directors of the Company that, to the best of our knowledge, nothing has come to the attention of the Board of Directors of the Company which may render the financial results for the year ended 30 June 2015 to be false or misleading in any material aspect.

This report is made in accordance with a resolution of the Directors.

Peter Bond
Director
25 September 2015

Craig Ricato
Director
25 September 2015

Lead Auditor's Independence Declaration under Section 307C of the *Corporations Act 2001*

To: the Directors of Linc Energy Ltd

I declare that, to the best of my knowledge and belief, in relation to the audit for the financial year ended 30 June 2015 there have been:

(i) no contraventions of the auditor independence requirements as set out in the *Corporations Act 2001* in relation to the audit; and

(ii) no contraventions of any applicable code of professional conduct in relation to the audit.

KPMG

Matthew McDonnell
Partner

Brisbane, Australia
25 September 2015

ANNUAL FINANCIAL REPORT

This financial report contains the consolidated financial statements for the consolidated entity consisting of Linc Energy Ltd and its subsidiaries (the Group). Information required by the Corporations Amendment Regulations 2010 in respect of the parent entity is included in note 33 of this report.

The financial report is presented in Australian Dollars.

Linc Energy Ltd is a company limited by shares, incorporated and domiciled in Australia. Its registered office and principal place of business is 32 Edward Street, Brisbane, Qld 4000.

A description of the nature of the entity's operations and its principal activities is included in the Review of Operations and activities on pages 9 to 25 and in the Directors' Report on pages 53 to 64, both of which are not part of this financial report.

Through the use of the internet, we have ensured that our corporate reporting is timely, complete, and available globally at minimum cost to the Company. All press releases, financial reports and other information are available at our Investors Centre on our website: www.lincenergy.com.

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

For the year ended 30 June 2015

Group	Notes	2015 $'000	2014 Restated* $'000
Continuing operations			
Revenue	2	87,786	148,390
Cost of sales	3	(125,149)	(112,379)
Gross profit		(37,363)	36,011
Sale of royalty	2	148,611	-
Gain on sale of available-for-sale assets	2	433	-
Other income	2	422	439
Expenses:			
Administration and corporate		(60,268)	(74,480)
Site operating costs		(5,215)	(6,875)
Exploration and evaluation		(1,283)	(2,135)
Technology development		(9,224)	(10,030)
Net foreign exchange gains / (losses)		8,715	(3,356)
Other expenses	4	(183,837)	(39,859)
Discount on sale of receivable	5	75	(13,982)
Results from operating activities		(138,934)	(118,267)
Finance income	6	3,942	1,223
Finance expenses	6	(92,157)	(69,306)
Net finance costs		(88,215)	(68,083)
Profit / (loss) before other financial instruments expenses and income tax		(227,149)	(186,350)
Other financial instruments expenses	6	(24,159)	(30,471)
Profit / (loss) before income tax		(251,308)	(216,821)
Income tax benefit / (expense)	8	2,297	(6,889)
Profit / (loss) for the year from continuing operations		(249,011)	(223,710)
Discontinued operation			
Profit / (loss) from discontinued operations, net of tax	7	(43,882)	(5,768)
Profit / (loss) for the period		(292,893)	(229,478)

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME (CONTINUED)

For the year ended 30 June 2015

Group	Notes	2015 $'000	2014 Restated* $'000
Other comprehensive income / (loss)			
Items that may be reclassified subsequently to profit or loss:			
Net change in the fair value of available-for-sale financial assets, net of transaction costs and tax	6	13,303	(3,432)
Foreign currency translation differences for foreign operations		18,226	(6,372)
Total items that may be reclassified subsequently to profit or loss		31,529	(9,804)
Total other comprehensive income / (loss) for the period, net of tax		31,529	(9,804)
Total comprehensive income / (loss) for the year		(261,364)	(239,282)
Profit / (loss) attributable to:			
Equity holders of Linc Energy Ltd		(292,832)	(227,180)
Non-controlling interests		(61)	(2,298)
Profit / (loss) for the year		(292,893)	(229,478)
Total comprehensive income / (loss) attributable to			
Equity holders of Linc Energy Ltd		(263,100)	(236,694)
Non-controlling interests		1,736	(2,588)
Total comprehensive income / (loss) for the year		(261,364)	(239,282)
Earnings per share attributable to the ordinary equity holders Linc Energy Ltd:		2015 Cents	2014 Cents
Basic earnings / (loss) per share	9	(49.19)	(41.21)
Diluted earnings / (loss) per share	9	(49.19)	(41.21)
Earnings per share attributable to continuing operations		Cents	Cents
Basic earnings / (loss) per share		(41.82)	(40.16)
Diluted earnings / (loss) per share		(41.82)	(40.16)

**Restated balances due to Discontinued Operation. Refer to note 7 for further details.*

The above consolidated statement of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at 30 June 2015

		Group		Company	
		2015	2014	2015	2014
	Notes	$'000	$;000	$'000	$'000
ASSETS					
Cash and cash equivalents	10	23,210	48,716	20,054	41,632
Trade and other receivables	11	14,186	20,721	2,957	2,688
Inventories	12	3,585	2,857	-	-
Available-for-sale assets	13	20,964	9,258	20,964	9,258
Other financial assets	14	7,990	-	-	-
Total current assets		69,935	81,552	43,975	53,578
Trade and other receivables	11	25,545	13,847	12,495	5,396
Intangibles	15	254,191	268,677	32,112	39,428
Property, plant and equipment	16	14,219	15,728	7,336	7,909
Oil and gas assets	17	442,164	561,109	-	-
Available-for-sale assets	13	2,156	2,058	2,156	2,058
Deferred tax assets	8	-	-	17,574	23,437
Other financial assets	14	3,099	-	-	-
Investment in subsidiaries		-	-	270,218	427,001
Receivables from subsidiaries				84,788	68,922
Total non-current assets		741,374	861,419	426,679	574,151
Total assets		811,309	942,971	470,654	627,729
LIABILITIES					
Trade and other payables	18	39,400	62,131	6,576	7,536
Borrowings	19	174,400	197,695	174,139	197,507
Provisions	20	9,088	8,193	2,476	1,717
Deferred revenue	21	3,000	4,211	3,000	4,211
Other financial liability	22	-	5,766	-	-
Total current liabilities		225,888	277,996	186,191	210,971
Trade and other payables	18	1,241	1,124	-	-
Borrowings	19	483,542	337,026	-	4
Provisions	20	57,734	43,518	7,236	5,393
Deferred revenue	21	12,250	13,333	12,250	13,333
Other financial liability	22	-	2,785	-	-
Total non-current liabilities		554,767	397,786	19,486	18,730
Total liabilities		780,655	675,782	205,677	229,701
Net assets		30,654	267,189	264,977	398,028
EQUITY					
Share capital	23	431,169	396,794	431,169	396,794
Reserves	24	71,349	51,163	30,560	26,803
Retained earnings / (accumulated losses)		(481,914)	(189,082)	(196,752)	(25,569)
Total equity attributable to equity holders		20,604	258,875	264,977	398,028
Non-controlling interest		10,050	8,314	-	-
Total equity		30,654	267,189	264,977	398,028

The above consolidated statement of financial position should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the year ended 30 June 2015

Group	Attributable to equity holders of the company								
in thousands of dollars $'000	Share capital	Foreign currency translation	Available-for-sale reserve	Other reserves	Share-based payments	Retained earnings	Total	Non-controlling interest	Total equity
Balance as at 1 July 2013	325,388	30,407	4,427	5,309	30,316	38,098	433,945	10,902	444,847
Total comprehensive income for the period									
Profit / (loss) for the period	-	-	-	-	-	(227,180)	(227,180)	(2,298)	(229,478)
Other comprehensive income									
Foreign currency translation differences for foreign operations	-	(6,082)	-	-	-	-	(6,082)	(290)	(6,372)
Net change in fair value of available-for-sale financial assets, net of transaction costs and tax	-	-	(3,432)	-	-	-	(3,432)	-	(3,432)
Total other comprehensive income	-	(6,082)	(3,432)	-	-	-	(9,514)	(290)	(9,804)
Total comprehensive income for the period	-	(6,082)	(3,432)	-	-	(227,180)	(236,694)	(2,588)	(239,282)
Transactions with owners, recorded directly in equity									
Contributions by and distributions to owners									
Share-based payment expense	-	-	-	-	7,797	-	7,797	-	7,797
Shares issued and transferred from share-based payment reserve on vesting of performance rights	8,339	-	-	-	(8,339)	-	-	-	-
Shares issued and transferred from share-based payment reserve on exercise of options	552	-	-	-	(229)	-	323	-	323
Shares issued from initial public offering and over allotment	55,499	-	-	-	-	-	55,499	-	55,499
Initial public offering capitalised costs, net of tax	(3,962)	-	-	-	-	-	(3,962)	-	(3,962)
Shares issued on exercise of call option	10,978	-	-	-	-	-	10,978	-	10,978
Cash settled share-based payments transferred from share-based payment reserve on vesting of performance rights	-	-	-	-	(78)	-	(78)	-	(78)
Cash settled share-based payments transferred from share-based payment reserve on vesting of warrants	-	-	-	-	(8,933)	-	(8,933)	-	(8,933)
Total contributions by and distribution to owners	71,406	-	-	-	(9,782)	-	61,624	-	61,624
Total transactions with owners	71,406	-	-	-	(9,782)	-	61,624	-	61,624
Balance as at 30 June 2014	**396,794**	**24,325**	**995**	**5,309**	**20,534**	**(189,082)**	**258,875**	**8,314**	**267,189**

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (CONTINUED)

For the year ended 30 June 2015

Group *in thousands of dollars $'000*	Attributable to equity holders of the company Share capital	Foreign currency translation	Available-for-sale reserve	Other reserves	Share-based payments	Retained earnings / (accumulated losses)	Total	Non-controlling interest	Total equity
Balance as at 1 July 2014	396,794	24,325	995	5,309	20,534	(189,082)	258,875	8,314	267,189
Total comprehensive income for the period									
Profit / (loss) for the period	-	-	-	-	-	(292,832)	(292,832)	(61)	(292,893)
Other comprehensive income									
Foreign currency translation differences for foreign operations	-	16,429	-	-	-	-	16,429	1,797	18,226
Net change in fair value of available-for-sale financial assets, net of transaction costs and tax	-	-	13,303	-	-	-	13,303	-	13,303
Total other comprehensive income	-	16,429	13,303	-	-	-	29,732	1,797	31,529
Total comprehensive income for the period	-	16,429	13,303	-	-	(292,832)	(263,100)	1,736	(261,364)
Transactions with owners, recorded directly in equity									
Contributions by and distributions to owners									
Share-based payment expense	-	-	-	-	3,662	-	3,662	-	3,662
Shares issued and transferred from share-based payment reserve on vesting of performance rights	13,206	-	-	-	(13,206)	-	-	-	-
Cash settled share-based payments transferred from share-based payment reserve on vesting of performance rights	-	-	-	-	(2)	-	(2)	-	(2)
Shares issued on conversion of convertible notes	21,169	-	-	-	-	-	21,169	-	21,169
Total contributions by and distribution to owners	34,375	-	-	-	(9,546)	-	24,829	-	24,829
Total transactions with owners	34,375	-	-	-	(9,546)	-	24,829	-	24,829
Balance as at 30 June 2015	**431,169**	**40,754**	**14,298**	**5,309**	**10,988**	**(481,914)**	**20,604**	**10,050**	**30,654**

The above consolidated statements of changes in equity should be read in conjunction with the accompanying notes.

CONSOLIDATED CASH FLOW STATEMENT

For the year ended 30 June 2015

	Notes	Group 2015 $'000	2014 $'000
Cash flows from operating activities			
Receipts from customers and other debtors (inclusive of goods and services tax)		94,412	164,836
Payments to suppliers and employees (inclusive of goods and services tax)		(110,880)	(135,727)
Interest and borrowing costs paid		(68,632)	(54,610)
Receipts / (payments) for commodity swaps		7,141	(7,076)
Net cash used in operating activities	10	(77,959)	(32,577)
Cash flows from investing activities			
Payments for property, plant and equipment		(596)	(317)
Proceeds from disposal of property, plant and equipment		501	37
Payments for software intangible		(161)	(229)
Payments for exploration and evaluation intangible		(19,015)	(5,420)
Payments for exploration and development of oil and gas assets		(77,216)	(184,349)
Receipts from Alaskan tax rebate funding		75	57,387
Sale of royalty		90,000	-
Net funds from receivable factoring		56,444	-
Proceeds from director's loans		-	498
Net cash transferred (to) / from term deposits held as security for guarantees and bonds or held as investments		(956)	13,378
Interest received		654	1,212
Net cash from used in investing activities		49,730	(117,803)
Cash flows from financing activities			
Proceeds from Initial Public Offering (IPO)		-	55,499
Capitalised payments from IPO		-	(5,622)
Proceeds from the exercise of share options		-	11,302
Proceeds from notes issues		134,931	-
Redemption of convertible notes		(61,794)	-
Net proceeds / (repayments) from KeyBank Reserve-based lending facility		(74,332)	72,328
Repayment of borrowings		-	(36,243)
Repayment of finance lease liabilities		(554)	(749)
Payments associated with financing activities		(13,037)	(5,492)
Payment for Fortress warrant		-	(9,791)
Net cash from financing activities		(14,786)	81,232
Net increase / (decrease) in cash and cash equivalents		(43,015)	(69,148)
Less increase in cash and cash equivalents attributable to discontinued operations disposed during the period		(6)	-
Cash and cash equivalents at 1 July		48,716	124,007
Effect of exchange rate fluctuations on cash held		17,515	(6,143)
Cash and cash equivalents at 30 June	10	23,210	48,716

The above consolidated cash flow statement should be read in conjunction with the accompanying notes.
Please note the above statement of cash flows includes cash flows from discontinued operations. Refer to note 7 for a summary of cash from / (used) in discontinued operations.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The principal accounting policies adopted in the preparation of these consolidated financial statements are set out below. These policies have been consistently applied to all the years presented, unless otherwise stated. Linc Energy Ltd is a company limited by shares, incorporated and domiciled in Australia. Its registered office and principal place of business is 32 Edward Street, Brisbane, Qld 4000. The Group is a for-profit entity and is primarily involved in the exploration for, development and production of conventional oil and gas and unconventional syngas through the utilisation of its underground coal gasification technology.

(a) Basis of preparation

Statement of Compliance

The consolidated financial statements of the Company and its subsidiaries (collectively the “Group”) are general purpose financial statements which have been prepared in accordance with the Australian Accounting Standards (AASBs) adopted by the Australian Accounting Standards Board (AASB), the Corporations Act 2001 and the Singapore Exchange SGX Mainboard Rule 1207 (5). The consolidated financial statements comply with International Financial Reporting Standards (IFRS) as adopted by the International Accounting Standards Board (IASB).

The consolidated financial statements were authorised for issue by the Board of Directors on 25 September 2015. The Directors have the power to amend and reissue the financial report.

Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis, except for the following material items in the statement of financial position:

- Available-for-sale financial assets which are recognised at fair value;
- Financial assets which are initially recognised at fair value; and
- Financial liabilities which are initially recognised at fair value.

Functional and presentation currency

These consolidated financial statements are presented in Australian dollars, which is the Company’s functional currency. All amounts have been rounded to the nearest thousand, unless otherwise indicated.

Basis of preparation

The financial statements for the year ended 30 June 2015 have been prepared on the going concern basis which assumes the continuity of normal business activities and the realisation of assets and the settlement of liabilities in the ordinary course of business.

For the year ended 30 June 2015, the Group recorded an operating loss after tax of $292,893,000 and cash outflows from operating activities of $77,959,000. The Group also has a net current liability of $155,953,000. The net current liability position at 30 June 2015 is primarily reflective of the contractual terms of the Convertible Notes due 2018 (CN) which provides for an option in favour of the CN holders who may require the Company to redeem some, all ($137,475,000) or none of the Notes on a single future date being 10 April 2016. It is currently unknown whether any of the CN holders would look to exercise their option on that date however under accounting standards the Company is obliged to assume that all CN holders will exercise their option and accordingly the full CN liability has been recorded as current at 30 June 2015.

The Group currently has a source of operating cash flow from its oil and gas assets in the Gulf Coast and Wyoming however cash flow forecasts prepared by the Company indicate the Group is dependent on a resolution with CN holders pertaining to the potential early redemption date of 10 April 2016 as operating cash flow is not forecast to be sufficient to meet the settlement of any significant portion of the CN liability. If an agreement can’t be reached with the CN holders, the Group may be required to refinance or repay the Notes, or seek additional financing.

In addition, the operating cash flows may not be sufficient to cover the interest payments due in the next twelve months, while working capital balances are sensitive to adverse operational developments including oil production, oil prices, and foreign exchange rates as well as adverse developments in the timing or outcome associated with various contingent and current liabilities.

Accordingly, the Group is dependent on the raising of additional funds. The Group’s ability to raise equity and/or refinance its debt will rely on investor and lender confidence that the Group's asset values can be realised through development or sale.

These conditions indicate a material uncertainty that may cast significant doubt about the ability of the Group to continue as a going concern.

The Company has prepared cash flow projections based on various options that include the raising of additional cash to support the ability of the Group to continue as a going concern. Some of the options currently available to the Company include:

- The Company has an established track record of successfully raising new capital or debt facilities.
- Linc Energy is pursuing various new capital or debt raising facilities. In addition, the Company has engaged the Royal Bank of Canada (RBC) as its financial advisor to assist in the execution of strategic initiatives focused on reshaping the Company's capital structure. RBC is working closely with our corporate team as we are continuing to engage widely with potential investors and existing stakeholders to be in a position to achieve a resolution with the CN holders and provide sufficient working capital for future commitments. A number of these discussions are advancing at the date of this report and the Company will continue to update the market as appropriate.
- In addition, if necessary the Company has the ability to sell core or non-core assets, which could include the Group's Umiat and Wyoming conventional oil assets in the USA or the SAPEX assets in Australia. The Group also has the ability to reduce the scope of, or delay its current or future exploration, development and commercialisation activities.

In summary, the Directors consider that there are reasonable funding options and other potential liquidity measures available to Linc Energy to ensure it will be able to pay its debts as and when they fall due for at least 12 months from the date of signing the directors declaration and are satisfied that the use of the going concern assumption is appropriate in the preparation of the financial statements at 30 June 2015.

Should the above options not be subsequently available to the Group, the use of the going concern assumption may not be appropriate, and material adjustments may be necessary to the carrying amount and/or classification of asset or liabilities.

Accounting policies

Certain comparative amounts in the financial statements have been reclassified to conform to the current year's presentation.

The Group has recognised the coal segment as a discontinued operation. A discontinued operation is a component of the Group's business, the operations and cash flows of which can be clearly distinguished from the rest of the Group and which:

- represent a separate major line of business or geographical area of operations;
- is part of a single co-ordinated plan to dispose or a separate major line of business or geographical area of operations; or
- is a subsidiary acquired exclusively with a view to re-sale.

Classification as a discontinued operation occurs at the earlier of disposal or when the operation meets the criteria to be classified as held-for-sale. The coal division meets the criteria to be classified as held-for sale as the asset was actively being marketed during the financial year and was subsequently sold.

The comparative statement of profit or loss and other comprehensive income has been re-presented as if the operations had been discontinued from the start of the comparative year.

Use of estimates and judgements

The preparation of the consolidated financial statements in conformity with AASB / IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimates are revised and in any future periods affected.

Information about critical judgements in applying accounting policies that have the most significant effect on the amounts recognised in the consolidated financial statements is included in the following notes:

- Note 8 - Income tax;
- Note 15 – Intangibles, including carrying value of goodwill, coal-to-liquids technology development costs

and exploration and evaluation costs;

- Note 17 – Oil and gas assets, including classification of assets and recoverability of assets;
- Note 19 – Borrowings, determination of fair value of embedded derivative; and
- Note 28 – Contingent assets and liabilities

Information about assumptions and estimation uncertainties that have a significant risk of resulting in a material adjustment within the next financial year are included in the following notes:

- Note 8 – Income tax
- Note 17 – Oil and gas assets, including reserve determination
- Note 20 – Provisions

Critical accounting estimates, judgements and assumptions

Estimates, judgements and assumptions are continually evaluated and are based on historical experience and other factors, including expectations of future events that may have a financial impact on the entity and that are believed to be reasonable under the circumstances. Actual results may differ from those estimates, judgements and assumptions.

The estimates, judgements and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Impairment of assets

In the absence of quoted market prices, estimates of the recoverable amounts of assets are based on the present value of future cash flows. For oil and gas assets, expected future cash flows are based on reserves, future production profiles, commodity prices and costs.

Exploration and evaluation

The Group capitalises exploration costs. The Group's policy for exploration and evaluation assets is set out in note 1(m) and requires certain estimates and assumptions as to future events and circumstances, particularly in relation to the assessments of whether economic quantities of reserves have been found. Estimates and assumptions may change as new information becomes available. If, after capitalising expenditure, management concludes that it is unlikely to recover expenditure through future exploitation or sale, then the relevant capitalised amount will be written off profit or loss.

Income tax – research and development

The Group provides for the amount of tax payable on its estimated assessable income for the year. A significant component in determining the amount payable is the estimate of research and development expenditure deductible in respect of current and prior years.

Oil and gas assets – reserve estimation

The amount of proved and probable reserves is reassessed at each reporting date for the purposes of assessing possible impairment of assets and calculating depletion of acquired oil and gas assets and capitalised exploration, evaluation and development costs. Reserves are determined by independent third party reserve certification consultants and conform to guidelines issued by the Society of Petroleum Engineers. Estimated reserve quantities incorporate assumptions about future development and production costs and expected oil commodity prices. These estimates can change from period to period due to changes in these assumptions and as additional geological data is generated through drilling operations.

Provision for site restoration

The Group has provided for site restoration costs to allow for any necessary decommissioning and rehabilitation work at its coal-to-liquids technology development sites in Chinchilla and Wyoming, in the event of cessation of all activities at these sites. This provision is based on the Directors' best estimate of the costs of this work, which is consistent with estimates submitted to and approved by the relevant regulatory authorities in each jurisdiction. However, during the year the Queensland Department of Environment and Heritage Protection (DEHP) requested the financial assurance bond for Chinchilla to be increased from $3,900,000 to $29,200,000. While this decision accepts a number of the Company's assertions in relation to the costs associated with rehabilitation, the main differences relate to methodology of and costs associated with processing water and impacted soil. The Company believes that the methodology applied in calculating the rehabilitation costs is consistent with relevant regulations and it has applied this methodology in the calculation of site provision. The Company has applied for stay of the decision with the DEHP which has been ratified. The Company is therefore not required to provide any increased financial assurance until the litigation appeal with the Lands Court is finalised.

The Group has also provided for the costs associated with rehabilitation and decommissioning in respect of its US oil production activities. Increases in the provision are capitalised to oil and gas assets and amortised over the life of the field using the units of production method based on economically recoverable reserves.

(b) Basis of consolidation

Business combinations

Business combinations are accounted for using the acquisition method as at the acquisition date, which is the date on which control is transferred to the Group. The Group controls an entity when it is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity. The acquisition date is the date on which control is transferred to the acquirer. Judgement is applied in determining the acquisition date and determining whether control is transferred from one party to another.

The Group measures goodwill at acquisition date as the fair value of the consideration transferred including the recognised amount of any non-controlling interest in the acquiree, less the net recognised amount (generally fair value) of the identifiable assets acquired and liabilities assumed, all measured as of the acquisition date.

Consideration transferred includes the fair values of the assets transferred, liabilities incurred by the Group to the previous owners of the acquiree, and equity interests issued by the Group. Consideration transferred also includes the fair value of any contingent consideration and share-based payment awards of the acquiree that are replaced mandatorily in the business combination.

The Group recognises a bargain purchase gain in the profit or loss if the cost of an acquisition is less than the Group's share of the net fair value of the identifiable net assets acquired.

Transaction costs that the Group incurs in connection with a business combination, such as finder's fees, legal fees, due diligence fees, and other professional and consulting fees, are expensed as incurred.

A contingent liability of the acquiree is assumed in a business combination only if such a liability represents a present obligation and arises from a past event, and its fair value can be measured reliably.

Non-controlling interest

Acquisitions of non-controlling interests are accounted for as transactions with owners in their capacity as owners and therefore no goodwill is recognised. The Group measures any non-controlling interest at its proportionate interest in the identifiable net assets of the acquiree.

Subsidiaries

Subsidiaries are entities controlled by the Group. The Group controls an entity when it is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases. The accounting policies of subsidiaries have been changed when necessary to align them with the policies adopted by the Group.

Loss of control

When the Group loses control over a subsidiary, it derecognises the assets and liabilities of the subsidiary, and any related non-controlling interest and other components of the entity. Any resulting gain or loss is recognised in profit and loss. Any interest retained in the former subsidiary is measured at fair value when control is lost.

Transactions eliminated on consolidation

Intra-group balances and transactions, and any unrealised income and expenses arising from intra-group transactions with the exception of unrealised foreign exchange gains or losses on intercompany receivables and payables, are eliminated in preparing the consolidated financial statements.

(c) Foreign currency translation

Transactions and balances

Foreign currency transactions are translated into the functional currency of the Group using the prior month average exchange rates or for material transactions at the prevailing rate at the dates of the transaction. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year-end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognised in profit or loss.

Foreign exchange gains and losses that relate to borrowings are presented in the statement of profit or loss and other comprehensive income within other financial instruments expenses. All other foreign exchange gains and losses are presented on a net basis within net foreign exchange gains/ (losses).

Group companies

The results and financial position of all Group entities that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- Assets and liabilities are translated at the closing rate at the reporting date of the Statement of Financial Position
- Income and expenses are translated at the exchange rate at the date of the transaction (or an average annual rate where not materially different), and
- All resulting exchange differences are recognised as a separate component of equity.

(d) Discontinued operation

A discontinued operation is a component of the Group's business, the operations and cash flows of which can be clearly distinguished from the rest of the Group and which:

- represent a separate major line of business or geographical area of operations;
- is part of a single co-ordinated plan to dispose or a separate major line of business or geographical area of operations; or
- is a subsidiary acquired exclusively with a view to re-sale.

Classification as a discontinued operation occurs at the earlier of disposal or when the operation meets the criteria to be classified as held-for-sale. The coal division met the criteria to be classified as held-for sale as the asset was being actively marketed and it was highly probable it would be sold within the next 12 months.

The comparative statement of profit or loss and other comprehensive income is re-presented as if the operations had been discontinued from the start of the comparative year.

(e) Revenue recognition

Revenue is measured at the fair value of the consideration received or receivable. Amounts disclosed as revenue are net of returns, trade allowances and amounts collected on behalf of third parties. Revenue is recognised for the major business activities as follows:

Gas sales revenue

The Group has entered into a gas sales contract with its customer containing a take or pay arrangement. Revenue from the sale of gas is recognised when the gas is delivered to the customer. If the contracted minimum volume of gas is not taken, the customer must pay for the minimum contracted volume.

Oil sales revenue

Revenue is recognised when the significant risks and rewards of ownership of the goods have passed to the buyer and can be measured reliably. Risks and rewards are considered passed to the buyer at the time goods are transported off site to the customer. Revenue from oil sales is recognised on the basis of the Group's net interest in a producing field.

Consulting services revenue

Revenue from consulting services is recognised in the reporting period in which the services are rendered. For fixed price contracts, revenue is measured under the percentage of completion method, based on actual milestones met under the contract conditions as a proportion of the total services to be provided.

Intellectual property licence revenue

Revenue from UCG intellectual property licence is recognised in profit or loss over the expected period that services are provided.

(f) Finance income and finance expenses

Finance income comprises interest income on bank accounts and term deposits and the present value discount on the sale of a royalty. Interest income is recognised as it accrues in profit or loss, using the effective interest method.

Finance expenses comprise of interest expense on borrowings and borrowing costs.

(g) Other financial instruments expenses

Other financial instruments expenses comprise of gains and losses on derivative financial instruments, foreign currency gains and losses on financial liabilities and change in the fair value of embedded derivative financial liabilities. All borrowing costs are recognised in profit or loss using the effective interest method.

(h) Income tax

The income tax benefit/expense comprises current and deferred tax. It is recognised in profit or loss except to the extent that it relates to a business combination, or items recognised directly in equity or in other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years. Current tax payable also includes any tax liability arising from the declaration of dividends.

Current tax assets and liabilities are offset only if certain criteria are met.

Deferred tax is recognised in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognised for the following temporary differences: the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss, differences relating to investments in subsidiaries and associates and jointly controlled entities to the extent that it is probable that they will not reverse in the foreseeable future and difference arising on the initial recognition of goodwill.

The measurement of deferred tax reflects the tax consequences that would follow the manner in which the Group expects, at the end of the reporting period, to recover or settle the carrying amount of its and assets and liabilities.

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted at the reporting date.

Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset current tax liabilities and assets, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realised simultaneously.

A deferred tax asset is recognised for unused tax losses, tax credits and deductible temporary differences, to the extent that it is probable that future taxable profits will be available against which they can be utilised. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realised.

In determining the amount of current and deferred tax the Group takes into account the impact of uncertain tax positions and whether additional taxes and interest may be due. The assessment relies on estimates and assumptions and may involve a series of judgements about future events. New information may become available that causes the Group to change its judgement regarding the adequacy of existing tax liabilities; such changes to tax liabilities will impact tax expense in the period that such a determination is made.

The Company and its wholly owned Australian resident entities are part of a tax consolidated group. As a consequence, all members of the tax consolidated group are treated as a single entity. The head entity within the tax-consolidated group is Linc Energy Ltd.

The Company, in conjunction with other members of the tax-consolidated group, has also entered into a tax sharing agreement. The tax sharing agreement provides for the determination of the allocation of income tax liabilities between the entities should the head entity default on its tax payment obligations. No amounts have been recognised in the financial statements in respect of this agreement as payment of any amounts under the tax sharing agreement is considered remote.

(i) Earnings per share

Basic earnings per share

Basic earnings per share is calculated by dividing the profit or loss attributable to equity holders of the Company by the weighted average number of ordinary shares outstanding during the financial year.

Diluted earnings per share

Diluted earnings per share adjusts the figures used in the determination of basic earnings per share to take into account the after income tax effect of interest and other financing costs associated with dilutive potential ordinary shares and the weighted average number of shares assumed to have been issued for no consideration in relation to dilutive potential ordinary shares.

(j) Cash and cash equivalents

Cash and cash equivalents includes cash on hand, deposits held at call with financial institutions and other short-term, highly liquid investments with original maturities of three months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

(k) Trade and other receivables

Trade and other receivables are recognised initially at fair value and subsequently measured at amortised cost, less provision for doubtful debts. Trade receivables are due for settlement generally within 30-90 day terms.

Collectability of trade receivables is reviewed on an ongoing basis. Debts which are known to be uncollectible are written off. A provision for doubtful receivables is established when there is objective evidence amounts will not be able to be collected according to the original terms of receivables. The amount of the provision is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the original effective interest rate. Cash flows relating to short-term receivables are not discounted if the effect of discounting is immaterial. The amount of the provision is recognised in profit or loss.

Government grants in relation to capital expenditures and investments are recognised initially as an adjustment to the cost of the assets when there is reasonable assurance that they will be received and that the Group will comply with the conditions associated with the grant.

(l) Inventories

Oil, raw materials and stores

Oil in tanks, raw materials and stores are stated at the lower of cost and net realisable value. The cost of inventories is based on the first-in first-out principle, and includes expenditure incurred in acquiring the inventories, production or conversion costs and other costs incurred in bringing them to their existing location and condition.

Net realisable value is the estimated selling price in the ordinary course of business, less the estimated costs of completion and selling expenses.

(m) Intangibles

Coal-to-liquids development costs

Costs incurred on coal-to-liquids development projects (relating to the design and testing of the Group's coal-to-liquids technology) are recognised as intangible assets when it is probable that the project will, after considering its commercial and technical feasibility, be completed and generate future economic benefits and its costs can be measured reliably. The expenditure capitalised comprises all directly attributable costs, including costs of materials, services, direct labour and an appropriate proportion of overheads. Other development expenditures that do not meet these criteria are recognised as an expense as incurred. Development costs previously recognised as an expense are not recognised as an asset in a subsequent period. Capitalised development costs are recorded as intangible assets and amortised from the point at which the asset is ready for use on a straight-line basis over its useful life.

The coal-to-liquids intangible asset is componentised into UCG technology with a 10 year useful life (6.5 years remaining) and GTL technology which will be amortised once ready for use.

Exploration and evaluation

Exploration and evaluation expenditure incurred is either written off as incurred or accumulated in respect of each identifiable area of interest. Costs are only carried forward to the extent that they are expected to be recouped through the successful development of the area, sale of the respective areas of interest or where activities in the area have not yet reached a stage which permits reasonable assessment of the existence of economically recoverable reserves and the Group continues to hold the rights to the tenement.

Accumulated costs in relation to an abandoned area are written off in full to profit or loss in the year in which the decision to abandon the area is made. When production commences, the accumulated costs for the relevant area of interest are tested for impairment and transferred to development costs or to oil and gas properties depending on the nature of the resource and amortised over the life of the area of interest according to the rate of depletion of the economically recoverable reserves.

A regular review is undertaken of each area of interest to determine the appropriateness of continuing to carry forward costs in relation to that area of interest. Restoration, rehabilitation and environmental costs necessitated by exploration and evaluation activities are expensed as incurred and treated as exploration and evaluation expenditure (see note 1(x)).

Goodwill

Goodwill represents the excess of the cost of an acquisition over the fair value of the Group's share of the net identifiable assets of the acquired subsidiary at the date of acquisition. Goodwill on acquisitions of subsidiaries is included in intangible assets. Goodwill is not amortised. Instead, goodwill is tested for impairment annually or more frequently if events or changes in circumstances indicate that it might be impaired and is carried at cost less accumulated impairment losses. Gains and losses on the disposal of an entity include the carrying amount of goodwill relating to the entity sold.

Goodwill is allocated to cash-generating units for the purpose of impairment testing. Each of those cash-generating units represents the Group's investment in each country of operation by each primary reporting segment.

(n) Research and development expenditure

The Group classifies the entire coal-to-liquids demonstration facility (pilot plant) and ongoing technology development at the site as research and development expenditure. Costs incurred in constructing the Group's coal-to-liquids demonstration facility have been capitalised and included within intangibles in the statement of financial position (refer note 1(m)). Costs that do not meet the recognition criteria of an intangible asset have been recognised in profit or loss.

(o) Property, plant and equipment

Items of property, plant and equipment are stated at historical cost less accumulated depreciation. Historical cost includes expenditure that is directly attributable to the acquisition of the items.

Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. All other repairs and maintenance are charged to profit or loss during the financial period in which they are incurred.

Land is not depreciated. Depreciation on other assets is calculated using the diminishing value method to allocate their cost or re-valued amounts, net of their residual values, over their estimated useful lives, as follows:

Buildings (freehold)	40 years
Motor vehicles	5 years
Office equipment and furniture	2 to 5 years
Plant and equipment	5 years

The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each reporting date. An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount (note 1(q)). Gains and losses on disposals are determined by comparing proceeds with carrying amount. These are included in profit or loss.

(p) Oil and gas assets

Oil and gas assets include the initial cost of acquisition, together with the cost of construction, installation or completion of infrastructure facilities such as pipelines or processing plants, transferred exploration and evaluation costs, and the cost of development wells. Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. All other repairs and maintenance are charged to profit or loss during the financial period in which they are incurred.

Oil and gas assets other than land are depreciated to their residual values on a unit of production basis over the economically recoverable proved and probable hydrocarbon reserves.

The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each reporting date. An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount (note 1(q)). Gains and losses on disposals are determined by comparing proceeds with carrying amount. These are included in profit or loss.

(q) Impairment of assets

Goodwill and intangible assets that have an indefinite useful life are not subject to amortisation but are tested annually for impairment or more frequently if events or changes in circumstances indicate that they might be impaired. Other assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable.

An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). In relation to oil and gas assets, shale oil, and coal segments, these are all assessed on an area of interest basis. The clean energy segment is assessed on a cash-generating basis. Non-financial assets other than goodwill that have previously suffered impairment are reviewed for possible reversal at each reporting date.

(r) Available-for-sale assets

Available-for-sale financial assets are non-derivative financial assets that are designated as available-for-sale. The Group's investments in equity securities are classified as available-for-sale financial assets and recognised at fair value which is determined by reference to the stock exchange closing share price at reporting date. Subsequent to initial recognition, changes in fair value, other than impairment losses, are recognised in other comprehensive income and presented within equity in the available-for-sale reserve. When an investment is disposed of or impaired, the cumulative gain or loss in equity is transferred to profit and loss.

(s) Trade and other payables

Trade and other payables amounts represent liabilities for goods and services provided to the Group prior to the end of financial year which remain unpaid. The amounts are unsecured with the Company endeavouring to pay all liabilities within agreed payment terms unless alternative arrangements are arranged with the supplier.

(t) Borrowings

Borrowings are initially recognised at fair value, net of transaction costs incurred. Borrowings are subsequently measured at amortised cost. Any difference between the proceeds (net of transaction costs) and the redemption amount is recognised in profit or loss over the period of the borrowings using the effective interest method. Fees paid on the establishment of loan facilities, which are incremental costs relating to the facility, are offset against the liability and amortised on an effective interest basis over the term of the facility.

(u) Compound financial instruments

Compound financial instruments issued by the Group comprise of convertible notes that can be converted to share capital at the option of the holder. The Group can settle the conversion by making a cash payment to the note holder or settle by the issue of shares. The liability component of the note is initially recognised at fair value and subsequently recognised at amortised cost using the effective interest rate method. The embedded derivative component is initially measured at fair value and subsequently measured at fair value through profit or loss at the end of each reporting period. Both the note liability and embedded derivative component are recognised as a part of borrowings in the statement of financial position.

(v) Derivative financial instruments

The Group uses derivative financial instruments to hedge its exposure to commodity price risk. The principal derivatives used are commodity oil price swap agreements and put and call options.

The Group records all derivative instruments as either financial assets or financial liabilities at fair value. The Group has not elected to designate its derivative instruments in a hedge relationship and, therefore, recognises all changes in fair value of its derivative financial instruments immediately through finance expenses in profit or loss.

(w) Leases

Leases in which the Group assumes substantially all the risks and rewards of ownership are classified as finance leases. Finance leases are capitalised at the lease's inception at the lower of the fair value and the present value of the minimum lease payments. The corresponding rental obligations, net of finance charges, are included in borrowings. Each lease payment is allocated between the liability and finance cost. The finance cost is charged to profit or loss over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period. The property, plant and equipment acquired under finance leases is depreciated over the shorter of the asset's useful life and the lease term.

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to profit or loss on a straight-line basis over the period of the lease.

(x) Provisions

Provisions are recognised when the Group has a present legal or constructive obligation as a result of past events and it is probable that an outflow of resources will be required to settle the obligation and the amount has been reliably estimated. Provisions are not recognised for future operating losses.

Where there are a number of similar obligations, the likelihood that an outflow will be required in settlement is determined by considering the class of obligations as a whole. A provision is recognised even if the likelihood of an outflow with respect to any one item included in the same class of obligations may be small.

If the effect is material, provisions are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the end of the reporting period. The discount rate used to determine the present value reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognised as finance expense.

Site restoration and rehabilitation

In accordance with its environmental obligations the Group recognises a provision for the cost of decommissioning its coal-to-liquids demonstration facility, rehabilitating its exploration drill holes and decommissioning and rehabilitating its oil and gas wells, pipelines and processing infrastructure. A provision for decommissioning and/or restoration and the related expense is recognised when an area is disturbed as a result of the Group's activities. A provision for rehabilitation and the related expense is recognised when a drilling program is completed.

Increases in decommissioning and rehabilitation provisions in respect of oil and gas activities are capitalised to oil and gas assets and amortised using the units of production basis over the economically recoverable reserves in the relevant area.

(y) Employee benefits

Share-based payments

Share-based compensation benefits were provided to employees via the Group's Performance Rights Plan and the previous Employee Option Plan. Information relating to these schemes is set out in note 30.

The fair value of rights granted under the Performance Rights Plan and options granted under the Employee Option Plan were recognised as an employee benefit expense with a corresponding increase in equity. The fair value was measured at grant date and recognised over the period during which the employees became unconditionally entitled to the rights and / or options (the "vesting period").

The fair value at grant date for performance rights was calculated based on the closing share price of Linc Energy Ltd on grant date. The fair value at grant date for options was independently determined using a Black-Scholes option pricing model that took into account the exercise price, the term of the option, the impact of the dilution, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield and the risk free interest rate for the term of the option.

The fair value of the options granted excluded the impact of any non-market vesting conditions, as these were included in assumptions about the number of options that were expected to become exercisable. At each reporting date the entity revised its estimate of the number of options that were expected to become exercisable. The employee benefit expense recognised each period took into account the most recent estimate.

Wages and salaries, annual leave, sick leave and short-term incentive bonuses

A liability or provision is recognised for the amount of wages and salaries, accumulated annual leave and sick leave and short term-incentive bonuses expected to be paid if the Group has a present legal or constructive obligation to pay the amounts as a result of past service provided by the employee and the obligation can be estimated reliably.

Long service leave

The liability for long service leave is recognised in the provision for employee benefits and measured as the present value of expected future payments to be made in respect of services provided by employees up to the reporting date using the projected unit credit method. Consideration is given to future expected wage and salary levels, experience of employee departures and periods of service. Expected future payments are discounted at the reporting date using corporate bond rates with terms to maturity that match the estimated future cash outflows.

Retirement benefit obligations

The Group contributes to defined contribution superannuation plans for all employees in accordance with relevant legislation. The Group makes fixed contributions at the current rate of 9.50 per cent of gross salary for Australian employees and the Group's obligations are limited to these contributions. Contributions are recognised as an expense as they become payable.

(z) Share capital

Ordinary shares are classified as equity. Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction.

When share capital recognised as equity is repurchased, the amount of consideration paid, including directly attributable costs, net of any tax effects is recognised as a deduction in equity.

Dividends are recognised as a liability in the period in which they are declared.

(aa) Goods and Services Tax (GST)

Revenues, expenses and assets are recognised net of the amount of associated GST, unless the GST incurred is not recoverable from the taxation authority. In this case it is recognised as part of the cost of acquisition of the asset or as part of the expense.

Receivables and payables are stated inclusive of the amount of GST receivable or payable. The net amount of GST recoverable from, or payable to, the taxation authority is included with other receivables or payables in the balance sheet.

Cash flows are presented on a gross basis. The GST components of cash flows arising from investing or financing activities which are recoverable from, or payable to the taxation authority, are presented as operating cash flows.

(bb) Fair value estimation

The fair value of financial assets and financial liabilities must be estimated for recognition and measurement or for disclosure purposes. The fair value of financial instruments traded in active markets (such as available-for-sale securities and financial assets at fair value through profit and loss) is based on quoted market prices at the end of the reporting period. The quoted market price used for financial assets held by the Group is the current bid price, while the current ask price is used for financial liabilities. The nominal value less estimated credit adjustments of trade receivables and payables are assumed to approximate their fair values. Where applicable, information about the assumptions made in determining fair values is disclosed in the notes specific to that assets or liability.

(cc) Segment reporting

Operating segments are reported in a manner consistent with the internal reporting provided to the Chief Executive Officer (CEO), who is the Group's chief operating decision maker.

An operating segment is a component of the Group that engages in business activities from which it may earn revenues and incur expenses, including revenues and expenses that relate to transactions with any of the Group's other components. All operating segments' operating results are regularly reviewed by the Group's CEO to make strategic decisions about resources to be allocated to the segment and assess its performance, and for which discrete financial information is available.

(dd) New accounting standards and interpretations

No new accounting policies and/or application of new and amended accounting standards have had a material impact on these consolidated financial statements.

The Group has not adopted the following accounting standards:

- *AASB 15 / IFRS 15 Revenue from Contracts with Customers* - This standard was issued by the International Accounting Standards Board in May 2014 and by the Australian Accounting Standards Board in December 2014 and becomes mandatory for the Group's 2018 financial statements. It is anticipated it will be adopted for that period. AASB 15 / IFRS 15 establishes principles for reporting the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers.
- *AASB 9 / IFRS 9 Financial Instruments* – This standard was issued in July 2014 and replaces the guidance in *IAS 39 Financial Instruments: Recognition and Measurement.* It becomes mandatory for the Group's 2019 financial statements and it is anticipated it will be adopted in that period. AASB 9 / IFRS 9 provides revised guidance on the classification and measurement of financial instruments including a new credit loss model for calculating impairment on financial assets.

  These new standards are currently being assessed for the impact, if any, on the Group's future financial results.

2. REVENUE AND OTHER INCOME

	Group	
	2015	2014
	$'000	$'000
Revenue from continuing operations		
Oil and gas sales revenue – USA	81,810	141,627
Clean Energy: Syngas sales revenue - Uzbekistan	3,058	2,637
Clean Energy: Consulting revenue	624	1,670
Clean Energy: Intellectual property revenue[1]	2,294	2,456
Total revenue from continuing operations	87,786	148,390
Sale of royalty		
Sale of Carmichael (Adani) royalty[2]	148,611	-
Total sale of royalty	148,611	-
Gain on sale of available-for-sale assets		
Gain on sale of available-for sale assets[3]	433	-
Total gain on sale of available-for-sale assets	433	-
Other income		
Sundry income	422	439
Total other income	422	439

[1] Clean Energy: Intellectual property revenue of $2,294,000 has been recognised for Exxaro Intellectual Property. A total of $4,750,000 revenue has been recognised life to date, with the remaining $15,250,000 being recognised as deferred revenue in the consolidated statement of financial position.

[2] Sale of Carmichael Royalty Deed to the Adani Group: On 27 August 2014 a Put and Call Option Deed was agreed between Linc Energy Ltd and the Adani Group, with regards to the sale of the Carmichael Royalty Deed. Upon exercise of the Put or Call Option, the Company transferred all of its rights, interests, benefits and obligations of the Carmichael Royalty Deed to the Adani Group for a total consideration of $155,000,000.
Under the agreement the Company received two tranches. The first tranche of $90,000,000 was received within five days of exercise and the second tranche of $65,000,000 was to be received on or before the expiry of twelve months from the date of exercise. As the second tranche was to be received outside of the Company's normal credit terms, it was measured at Fair Value and discounted to the Present Value. The Present Value has been discounted to $58,611,000; therefore the total revenue recognised for the period was $148,611,000.

[3] During the year the Company sold shares in one of its listed securities investments. The gain represents the difference between the fair value and sale proceeds and a transfer of equity being held in the available-for-sale reserve.

3. EXPENSES

Profit / (loss) before income tax includes the following specific expenses:

	Group	
	2015	2014
	$'000	$'000
Cost of sales		
Oil and gas lease operating expenses	20,958	20,492
Other oil and gas production expenses	244	-
Royalties and production taxes	6,681	8,270
Work over expenses	8,474	7,679
Depletion expense of oil & gas assets	86,327	73,864
Production costs – Uzbekistan	2,465	2,074
Total cost of sales	125,149	112,379
Depreciation		
Buildings	11	11
Motor vehicles	494	453
Office equipment and furniture	741	876
Plant and equipment	1,157	1,317
Oil and gas field infrastructure, plant and equipment	1,675	1,527
Total depreciation	4,078	4,184
Amortisation		
Coal-to-liquids technology development	1,808	1,808
Software	676	920
Total amortisation	2,484	2,728
Employee benefits expenses		
Salaries and wages	27,902	33,485
Contributions to defined contribution superannuation and pension plans	1,928	2,003
Other employee costs	3,180	3,441
Increase in provision for employee entitlements	917	1,082
Share-based payments	3,520	9,203
Total employee benefits expenses	37,447	49,214
Net (gain) / loss on disposal of non-current assets	193	(9)
Research and development expenditure	-	546

4. OTHER EXPENSES

	Group	
	2015	2014
	$'000	$'000
Impairment expense – oil and gas assets[1] (note 17)	173,351	34,390
Impairment expense – available-for-sale assets[2] (note 13)	3,768	-
Impairment expense – intangible assets	-	5,469
Loss on sale of intangible assets[3]	358	-
Other expenses – oil and gas assets	6,360	-
Total other expenses	183,837	39,859

[1] On 28 July 2015, Haas Petroleum Engineering Services, Inc. issued a reserve report for the US Gulf Coast assets effective 30 June 2015 estimating Proved (1P) reserves of 7.7 mmbl and 3.3 bcf of natural gas (equating to 8.3 mmboe) and prospective resource of 3.3 mmbl and 4.7 bcf of natural gas (equating to 4.0 mmboe). The total PV10% valuation of the Gulf Coast asset is $253,305,000 (USD$193,905,000) and is solely attributed to 1P Reserves. The decrease in value relative to the last Qualified Persons Report (QPR) issued in December 2013 is primarily due to a decrease in PDNP and PUD reserves from restricted drilling program as well as decline in oil prices over the period.

On 30 July 2015, Ryder Scott Company L.P. (Ryder Scott) issued a reserve report for the Wyoming assets effective 30 June 2015 estimating Proved (1P) reserves of 551 mmbl and Possible reserves of 66.9 mmbl (3P of 67.5mmbl) . The total PV10% valuation of the Wyoming asset is $559,637,000 (USD$428,402,000) comprised of Proved reserves of $7,339,000 (USD$5,618,000) and Possible reserves of $552,298,000 (USD$422,784,000). The decrease relative to the last QPR report issued in December 2013 was primarily due to a decline in oil prices over the period.

An impairment test was conducted on the oil and gas assets held as at 30 June 2015 and certain assets were identified as being impaired due to their net book values being higher than the discounted reserves valuation. Consequently the book values of certain oil and gas assets have been reduced by $173,351,000 (USD$147,952,000) and an impairment expense recognised in profit and loss.

An impairment loss is recognised at reporting date when the balance of an asset's carrying amount exceeds its recoverable amount. The carrying amount of the asset is based upon cost incurred less accumulated depletion. For the purposes of assessing impairment, assets are grouped on a field basis which is the lowest reasonable level for which there are separately independent and identifiable cash inflows from assets or a group of assets.

The recoverable amount is based upon a third-party Qualified Persons Report issued to the Company. The reserve report is derived from the analysis of remaining proven reserves (1P) at a forward strip pricing rate which combines future price predictions from three well-known oil and gas valuation companies. In calculating impairment, the recoverable amount is based upon the estimated cash flows at a discount rate of 10%.

[2] One of the Company's listed investments was impaired at 31 December 2014 as its fair value had declined significantly below the acquisition cost. At 30 June 2015 the fair value has significantly increased but under AASB 139 / IAS 39, impairment losses on available-for-sale equity instruments cannot be reversed through profit or loss. The increase in fair value has been recognised as a revaluation and is recognised in the available-for-sale reserve in other comprehensive income.

[3] During the year the Company sold its partial block extraction (PBE) system technology and recognised a loss on sale.

5. DISCOUNT ON SALE OF RECEIVABLES

	Group	
	2015	2014
	$'000	$'000
Alaskan tax rebate funding	(75)	13,982
Total discount on sale of receivable	(75)	13,982

During the year the Company was reimbursed $211,000 from the purchaser of the oil and gas production tax credits pursuant to Alaska Statute 43.55.023. The reimbursements were due to the repayment of disallowed credits.

On 23 December 2014, the Company reimbursed $136,000 to one of its non-controlling interest partners, their portion of the oil and gas production tax credits. The net result to the Group was a gain of $75,000.

In the prior financial year the Company sold its rights to certain oil and gas production tax credits pursuant to Alaska Statute 43.55.023 amounting to $71,369,000. Net proceeds of $57,387,000 were received resulting in a discount on sale of the receivable of $13,982,000.

6. FINANCE INCOME, FINANCE EXPENSES AND OTHER FINANCIAL INSTRUMENTS EXPENSES

	Group	
	2015	2014
	$'000	$'000
Finance income recognised in profit and loss		
Interest income on cash and cash equivalents	646	1,204
Interest income on loans	101	19
Present value discount on sale of royalty	3,195	-
Total finance income	3,942	1,223
Finance expenses recognised in profit and loss		
Interest and borrowing costs paid or payable	(86,796)	(69,306)
Finance expenses on Receivable Factoring Facility Agreement	(5,361)	-
Total finance expenses	(92,157)	(69,306)
Net finance costs	(88,215)	(68,083)
Other financial instruments expenses recognised in profit and loss		
Net gain / (loss) on foreign currency options	-	(958)
Net gain / (loss) on commodity swaps	28,944	(13,822)
Gain / (loss) on modification of convertible notes	(36,286)	(997)
Net change in unrealised foreign exchange gain / (loss) on convertible notes	(37,412)	5,013
Net change in fair value of embedded derivatives from convertible notes at fair value through profit or loss	20,595	(19,707)
Total other financial instruments expenses	(24,159)	(30,471)
Recognised in other comprehensive income		
Net change in fair value of available-for-sale financial assets, net of transaction costs and tax	13,303	(3,432)

7. DISCONTINUED OPERATION

On 14 February 2015, the Company entered into an arrangement to sell its conventional coal business, New Emerald Coal Ltd (NEC), to United Queensland Resources Pty Limited (United), a part of United Mining Group which included the agreements to acquire the Blair Athol Coal Mine from Blair Athol Joint Venture, the Teresa development project including its Gladstone port capacity, the Pentland and Dalby development projects and Linc Energy's Queensland greenfield exploration tenure.

The sale of the conventional coal business was subject to shareholders' approval at the Extraordinary General Meeting held on 14 May 2015 and was concluded 21 May 2015.

The Company classified its Coal segment as a discontinued operation. The Coal segment was not previously classified as held-for-sale or as a discontinued operation. The comparative consolidated statement of profit or loss and other comprehensive income has been restated to show the discontinued operation separately from continuing operations.

(a) Results of discontinued operation

	2015 $'000	2014 $'000
Revenue	1,181	-
Expenses	(55,197)	(9,245)
Results from operating activities	(54,016)	(9,245)
Income tax (expense) / benefit	-	3,477
Results from operating activities, net of tax	(54,016)	(5,768)
(Loss) / gain on sale of subsidiary	10,134	-
Profit / (loss) for the year after tax, net of tax	(43,822)	(5,768)
Earnings / (loss) per share attributable to discontinued operation:		
Basic earnings / (loss) per share (cents)	(7.37)	(1.05)
Diluted earnings / (loss) per share (cents)	(7.37)	(1.05)

(b) Cash flows from (used in) discontinued operation

	2015 $'000	2014 $'000
Net cash from / (used) in operating activities	(7,495)	(651)
Net cash used in investing activities	(810)	(942)
Net cash flow for the year	(8,305)	(1,593)

(c) Effect of disposal on the financial position of the Group

	2015 $'000
Cash and cash equivalents	6
Trade and other receivables	527
Intangibles	1,247
Net assets	**1,780**
Trade and other payables	5,914
Net liabilities	5,914
Net liability position	**4,134**
	-
Consideration received[1]	
Cash and cash equivalents disposed of	6
Net cash outflow	6

[1] On 21 May 2015, the Company elected to convert amounts payable by United Queensland Resources Pty Limited (United), under the Share Sale Agreement into a loan. The total amount advanced to United under the Loan Agreement upon completion was $7,179,000. This includes $6,000,000 for the sale of NEC and $1,179,000 for amounts advanced to United. Interest is payable on the amount outstanding monthly in arrears at 12.5% per annum. The loan is repayable on or before 21 May 2017, unless the Loan Agreement is terminated earlier in accordance with its terms.

At 30 June 2015, the amount advanced under the loan was $7,179,000.

(d) (Loss) / gain on discontinued operation

	2015 $'000
Net liabilities of subsidiary prior to sale	4,134
Loan receivable for sale of subsidiary	6,000
(Loss) / gain on sale of subsidiary	10,134

8. INCOME TAX

	Group 2015 $'000	Group 2014 $'000
(a) Income tax expense / (benefit)		
The major components of income tax expense are:		
Current income tax		
Current income tax charge	10,046	20,174
Adjustments in respect of current income tax of previous years	2,463	1,713
Deferred income tax		
Relating to origination and reversal of temporary differences	(14,806)	(18,475)
Income tax expense / (benefit) reported in the statement of comprehensive income	(2,297)	3,412
(b) Amounts charged or credited directly to equity		
Deferred income tax related to items charged / (credited) directly to equity:		
Contributed equity	-	(1,698)
Available-for-sale investment reserve	2,411	(1,471)
Income tax expense / (credit) reported in equity	2,411	(3,169)

(c) Numerical reconciliation between aggregate tax expense / (benefit) recognised in the statement of comprehensive income and income tax expense / (benefit) calculated per the statutory income tax rate

A reconciliation between tax expense / (benefit) and the product of accounting profit before income tax multiplied by the Group's applicable income tax rate is as follows:

	2015 $'000	2014 $'000
Accounting profit / (loss) before tax from continuing operations	(251,308)	(216,821)
At the parent entity's statutory income tax rate of 30% (2014: 30%)	(75,392)	(67,817)
Amounts not deductible / (taxable) in calculating taxable income:		
Share-based payments (equity settled)	1,056	2,761
Under/over provision from prior years	2,620	(20,369)
Research and development	-	164
Foreign tax rate differential	(25,231)	(5,008)
Research and development tax incentive	-	(219)
Finance costs	(8,574)	(10,312)
Other	23	2,795
Tax losses (not previously) / not recognised	4	
Current year	103,201	101,417
Income tax (benefit) / expense from continuing operations	(2,297)	3,412

	Group	
	2015	2014
	$'000	$'000
Deferred income tax at 30 June relates to the following:		
(i) Deferred tax assets		
Temporary differences attributable to:		
Share issue expenses	2,437	3,249
Provisions	2,525	2,143
Accruals	158	221
Property, plant and equipment	6,084	15,827
Other	10,645	7,021
Deferred income	4,575	5,263
Research and development tax offset	26,951	22,237
Tax losses	6,854	82,191
Unrealised FX	-	609
Exploration capitalised	13,362	-
Investments	1,960	-
Finance costs	15,135	-
Total deferred tax assets	90,686	138,761
Set-off of deferred tax liabilities pursuant to set-off provisions	(90,686)	(138,761)
Net deferred tax assets	-	-
(ii) Deferred tax liabilities		
Temporary differences attributable to:		
Exploration capitalised	55,352	100,042
Investments	25,037	42,034
Finance costs	-	(3,343)
Unrealised foreign exchange	2,075	-
Available for sale	3,870	-
Other	4,352	28
Total deferred tax liabilities	90,686	138,761
Set-off of deferred tax liabilities pursuant to set-off provisions	(90,686)	(138,761)
Net deferred tax liabilities	-	-

(c) Unrecognised tax losses

At 30 June 2015, we do not recognise total tax losses of $210,689,000 (2014: $101,454,000). Tax losses in Australia are $46,518,000 (2014: $43,900,000) and tax losses in the USA are USD$125,673,000 (2014: USD$54,210,000).

(d) Franking credits

At 30 June 2015 the Australian tax consolidated group has 18,190,166 (2014: 18,190,166) imputation credits available for use in future periods resulting from payments of Australian federal income tax in 2012/13.

9. EARNINGS PER SHARE

	Group	
	2015	2014
	Cents	Cents
Basic earnings per share		
Profit (loss) attributable to the ordinary equity holders of the Company	(49.19)	(41.21)
Diluted earnings per share		
Profit (loss) attributable to the ordinary equity holders of the Company	(49.19)	(41.21)

	Number	Number
Weighted average number of ordinary shares		
Issued shares at 1 July	587,918,910	519,468,416
Effect of shares issued during the period	7,383,363	31,864,845
Weighted average number of ordinary shares at 30 June	595,302,273	551,333,261
Weighted average number of ordinary shares (diluted)		
Weighted average number of ordinary shares (diluted) at 30 June	595,302,273	551,333,261

	2015 $'000	2014 $'000
Profit / (loss) from continuing operations attributable to ordinary shareholders (basic)	(248,950)	(221,412)
Profit / (loss) from continuing operations attributable to ordinary shareholders (diluted)	(248,950)	(221,412)

Impact of transactions subsequent to year end

Subsequent to the end of the financial year, the Company voided 7,052,498 shares that were issued in error on 21 May 2015 and 4 May 2015 as part of the conversion of USD$16,700,000 face amount of the Company's USD$200,000,000 7% Convertible Notes due 2018. The number of issued and paid-up shares in the capital of the Company has decreased to 615,966,776 equating to $425,545,587. This would have impacted earnings per share as follows:

	Cents
Basic earnings per share	
Profit (loss) attributable to the ordinary equity holders of the Company	(49.26)
Diluted earnings per share	
Profit (loss) attributable to the ordinary equity holders of the Company	(49.26)

	Number
Weighted average number of ordinary shares	
Issued shares at 1 July	587,918,910
Effect of shares issued during the period	6,492,820
Weighted average number of ordinary shares at 30 June	594,411,730
Weighted average number of ordinary shares (diluted)	
Weighted average number of ordinary shares (diluted) at 30 June	594,411,730

10. CASH AND CASH EQUIVALENTS

	Group	
	2015	2014
	$'000	$'000
Cash at bank and on hand	23,210	48,716
	23,210	48,716

Reconciliation of profit / (loss) after income tax to net cash outflow from operating activities

Profit / (loss) for the year	(292,893)	(229,478)
Finance income	(3,874)	(1,223)
Interest expense	17,700	1,048
Financial instruments expenses	2,775	38,519
Net foreign exchange (gain) or loss on convertible notes	37,412	(5,013)
Net (gain) or loss on sale of non-current assets	551	(10)
Net (gain) / loss on discount on sale of receivable	(75)	13,982
Loss from discontinued operation	43,882	-
(Gain) on sale of available-for sale assets	(433)	-
Net (gain) or loss on foreign exchange	(8,479)	2,617
Depreciation, amortisation, accretion and depletion	92,889	80,776
Bad debt expense	102	-
Non cash employee benefits (share-based payments)	3,520	8,654
Recognition of deferred tax on items directly in equity	-	1,698
Impairment on available-for-sale-financial assets	3,768	-
Impairment on oil and gas assets	173,352	34,390
Impairment on intangible assets	-	5,469
Sale of royalty	(148,611)	-
Financing activities in profit and loss	(1,577)	(5,468)
Changes in operating assets		
Decrease / (increase) in trade and other receivables	6,772	19,041
Decrease / (increase) in prepayments	2,393	(2,293)
Decrease / (increase) in inventories	(178)	3
Increase / (decrease) in trade and other payables	(8,093)	(15,085)
Increase / (decrease) in deferred revenue	(2,294)	17,544
(Decrease) / increase in other provisions	3,431	2,070
(Increase) / decrease in deferred tax assets	48,075	19,319
(Decrease) / increase in deferred tax liabilities	(48,075)	(19,136)
Net cash outflow from operating activities	(77,960)	(32,577)

Non-cash investing activities		
Sale of Coal business	6,000	-
Non-cash financing activities		
Issue of ordinary shares upon conversion of convertible notes	21,169	-

11. TRADE AND OTHER RECEIVABLES

	Group	
	2015	2014
	$'000	$'000
Current		
Trade receivables	11,265	14,916
Other receivables (a)	789	986
Prepayments	1,416	2,845
Deposits (b)	140	1,974
Proceeds from sale of available-for sale assets	576	-
Total current trade and other receivables	14,186	20,721
Non-current		
Deposits (c)	5,522	7,970
Term deposits (d)	12,204	5,215
Loan receivable (e)	7,179	-
Other receivable	640	662
Total non-current trade and other receivables	25,545	13,847

None of the trade and other receivables are impaired or past due but not impaired. Due to the short-term nature of current receivables, their carrying amount is assumed to approximate their fair value. The fair values of non-current receivables are consistent with their carrying amounts. The Group's exposure to credit and market risks is discussed in note 26.

(a) Current other receivables are amounts generally arising from Business Activity Statement refunds, VAT refunds, and accrued interest on deposits.
(b) Current deposits relate to rental bonds to be refunded to the business for an office that was closed on 30 June 2015.
(c) Non-current deposits relate to security held in relation to mining tenements. These deposits are returned on relinquishment of a tenement subject to satisfactory compliance with environmental and other regulatory requirements. Funds also held in this account relate to normal trade deposits for example, rental bonds on property leases.
(d) Term deposits are held by banking institutions as security against guarantees and credit card facilities of the Group. These funds are not available for general use as working capital.
(e) On 21 May 2015, the Company elected to convert amounts payable by United Queensland Resources Pty Limited (United), under the Share Sale Agreement into a loan. The total amount advanced to United under the Loan Agreement upon completion was $7,179,000. This includes $6,000,000 for the sale of NEC and $1,179,000 for amounts advanced to United. Interest is payable on the amount outstanding monthly in arrears at 12.5% per annum. The loan is repayable on or before 21 May 2017, unless the Loan Agreement is terminated earlier in accordance with its terms. As at 30 June 2015 the balance of the loan is $7,179,000.

12. INVENTORIES

	Group	
	2015	2014
	$'000	$'000
Raw materials and stores – at cost	**3,585**	2,857

13. AVAILABLE-FOR-SALE ASSETS

	Group	
	2015	2014
	$'000	$'000
Current		
Listed equity security (a)	**20,964**	9,258
Non-current		
Listed equity securities	**2,156**	2,058
Total available-for-sale assets	**23,210**	2,058

(a) The Company is currently selling shares in one of its listed investments, with the completion expected to occur within the next twelve months.

One of the Company's listed investments was impaired at 31 December 2014 as its fair value had declined significantly below the acquisition cost. At 30 June 2015 the fair value has significantly increased but under AASB 139 / IAS 39, impairment losses on available-for-sale equity instruments cannot be reversed through profit or loss. The increase in fair value has been recognised as a revaluation and is recognised in the available-for-sale reserve in other comprehensive income.

The carrying amount of the listed equity securities is equal to their fair value. The fair value of listed securities has been calculated using prices quoted on the Australian Securities Exchange and AIM London Stock Exchange at balance date or the last trading date during the period. The Group's exposure to risk is discussed in note 26.

14. OTHER FINANCIAL ASSETS

	Group	
	2015	2014
	$'000	$'000
Current		
Commodity swap contracts (oil hedges)	7,990	-
Non-current		
Commodity swap contracts (oil hedges)	3,099	-
Total other financial assets	11,089	-

In the prior financial year, commodity swaps were recognised as liabilities. Refer to note 26 for details of the Group's commodity swap contracts.

15. INTANGIBLES

Group	Coal-to-liquids technology development (a) $'000	Exploration and evaluation (b) $'000	Software $'000	Goodwill $'000	Technology licences $'000	Total $'000
Year ended 30 June 2015						
Cost						
Opening balance	85,053	239,928	4,350	1,292	197	330,820
Additions (at cost)	-	18,675	234	-	-	18,909
Disposals	-	(398)	-	-	-	(398)
Transfer to assets held in discontinued operations (c)	-	(41,993)	(433)	-		(42,426)
Exchange rate movements	-	13,112	160	-	-	13,272
Closing balance	85,053	229,324	4,311	1,292	197	320,177
Amortisation and impairment losses						
Opening balance	(54,260)	(5,330)	(2,356)	-	(197)	(62,143)
Amortisation	(1,808)	-	(676)	-	-	(2,484)
Impairment Loss	-	-	-	-	-	-
Exchange rate movements	-	(1,228)	(131)	-	-	(1,359)
Closing balance	(56,068)	(6,558)	(3,163)	-	(197)	(65,986)
Closing net book amount	28,985	222,766	1,148	1,292	-	254,191
Year ended 30 June 2014						
Cost						
Opening balance	85,053	235,070	3,783	1,292	197	325,395
Additions (at cost)	-	6,584	589	-	-	7,173
Disposals	-	(15)	-	-	-	(15)
Exchange rate movements	-	(1,711)	(22)	-	-	(1,733)
Closing balance	85,053	239,928	4,350	1,292	197	330,820
Amortisation and impairment losses						
Opening balance	(52,452)	-	(1,452)	-	(197)	(54,101)
Amortisation	(1,808)	-	(920)	-	-	(2,728)
Impairment Loss (c)	-	(5,469)	-	-	-	(5,469)
Exchange rate movements	-	139	16	-	-	155
Closing balance	(54,260)	(5,330)	(2,356)	-	(197)	(62,143)
Closing net book amount	30,793	234,598	1,994	1,292	-	268,677

(a) Amortisation of the coal-to-liquids technology development is included within technology development expenses and intangible software amortisation included within administration and corporate expenses in the statement of comprehensive income.

(b) The recoverability of the carrying amount of the exploration and evaluation assets is dependent on the successful development and commercial exploitation or sale of the respective areas of interest. Costs are transferred to oil and gas assets or to other development assets once oil or coal reserves are certified and the Group commences development of the resource.

(c) Refer to note 7, for further details of intangible assets transferred to discontinued operations.

Impairment tests for goodwill

Goodwill is allocated to the Group's cash-generating units identified according to reportable business segment and region of operation:

	Group	
	2015	2014
	$'000	$'000
Asia	**1,292**	1,292
UCG (Clean Energy)	**1,292**	1,292
Total		

Recoverable amount of Goodwill with an indefinite life

The recoverable amount of Goodwill is determined based on fair value less costs to sell. Fair value is determined as the amount for which the underlying asset (equity securities of JSPC Yerostigaz) could be exchanged between willing parties in an arm's length transaction. The Directors' believe that the recoverable amount of Yerostigaz exceeds the carrying value of goodwill.

16. PROPERTY, PLANT AND EQUIPMENT

Group	Land and buildings $'000	Motor vehicles $'000	Office equipment and furniture $'000	Plant and equipment $'000	Total $'000
Year ended 30 June 2015					
Cost					
Opening balance	4,768	2,933	5,310	12,922	25,933
Additions	-	472	503	153	1,128
Disposals	(162)	(478)	(737)	(808)	(2,185)
Exchange rate movements	30	387	853	1,079	2,349
Closing balance	4,636	3,314	5,929	13,346	27,225
Accumulated depreciation					
Opening balance	(90)	(1,620)	(2,977)	(5,518)	(10,205)
Depreciation charge	(11)	(494)	(741)	(1,157)	(2,403)
Disposals	-	360	348	6	714
Exchange rate movements	-	(221)	(468)	(423)	(1,112)
Closing balance	(101)	(1,975)	(3,838)	(7,092)	(13,006)
Closing net book amount	4,535	1,339	2,091	6,254	14,219
Year ended 30 June 2014					
Cost					
Opening balance	4,773	2,900	4,909	13,034	25,616
Additions	-	203	506	103	812
Disposals	-	(123)	(29)	-	(152)
Exchange rate movements	(5)	(47)	(76)	(215)	(343)
Closing balance	4,768	2,933	5,310	12,922	25,933
Accumulated depreciation					
Opening balance	(79)	(1,273)	(2,146)	(4,312)	(7,810)
Depreciation charge	(11)	(453)	(876)	(1,317)	(2,657)
Disposals	-	87	12	-	99
Exchange rate movements	-	19	33	111	163
Closing balance	(90)	(1,620)	(2,977)	(5,518)	(10,205)
Closing net book amount	4,678	1,313	2,333	7,404	15,728

Leased assets

Assets held under finance leases have a net book value of $952,000 (2014: $1,482,000).

17. OIL AND GAS ASSETS

Group	Undeveloped	In development	Producing	Field infrastructure, plant and equipment	Total
	$'000	$'000	$'000	$'000	$'000
Year ended 30 June 2015					
Cost					
Opening balance	86,243	46,678	577,941	18,387	729,249
Additions (net of rebates)	302	36,440	2,487	-	39,229
Transfers	-	(50,118)	50,118	-	-
Provision for closure costs	-	-	(435)	-	(435)
Disposals	-	-	(221)	-	(221)
Exchange rate movements	19,874	10,757	133,179	4,237	168,047
Closing balance	106,419	43,757	763,069	22,624	935,869
Accumulated depreciation, depletion					
Opening balance	-	-	(164,092)	(4,048)	(168,140)
Accumulated depreciation, depletion	-	-	(83,889)	(1,675)	(85,564)
Impairment	-	-	(173,352)	-	(173,352)
Exchange rate movements	-	-	(65,560)	(1,089)	(66,649)
Closing balance	-	-	(486,893)	(6,812)	(493,705)
Closing net book amount	106,419	43,757	276,176	15,812	442,164
Year ended 30 June 2014					
Cost					
Opening balance	84,473	67,525	450,721	18,963	621,682
Additions (net of rebates)	4,410	115,871	6,077	-	126,358
Transfers	(75)	(134,922)	134,997	-	-
Provision for closure costs	-	-	(164)	-	(164)
Disposals	-	(292)	(135)	-	(427)
Exchange rate movements	(2,565)	(1,504)	(13,555)	(576)	(18,200)
Closing balance	86,243	46,678	577,941	18,387	729,249
Accumulated depreciation, depletion					
Opening balance	-	-	(63,504)	(2,640)	(66,144)
Accumulated depreciation, depletion	-	-	(71,641)	(1,527)	(73,168)
Impairment	-	-	(34,390)	-	(34,390)
Exchange rate movements	-	-	5,443	119	5,562
Closing balance	-	-	(164,092)	(4,048)	(168,140)
Closing net book amount	86,243	46,678	413,849	14,339	561,109

Impairment of oil and gas assets

On 28 July 2015, Haas Petroleum Engineering Services, Inc. issued a reserve report for the US Gulf Coast assets effective 30 June 2015 estimating Proved (1P) reserves of 7.7 mmbl and 3.3 bcf of natural gas (equating to 8.3 mmboe) and prospective resource of 3.3 mmbl and 4.7 bcf of natural gas (equating to 4.0 mmboe). The total PV10% valuation of the Gulf Coast asset is $253,305,000 (USD$193,905,000) and is solely attributed to 1P Reserves. The decrease in value relative to the last Qualified Persons Report (QPR) issued in December 2013 is primarily due to a decrease in PDNP and PUD reserves from restricted drilling program as well as decline in oil prices over the period.

On 30 July 2015, Ryder Scott Company L.P. (Ryder Scott) issued a reserve report for the Wyoming assets effective 30 June 2015 estimating Proved (1P) reserves of 551 mmbl and Possible reserves of 66.9 mmbl (3P of 67.5mmbl) . The total PV10% valuation of the Wyoming asset is $559,637,000 (USD$428,402,000) comprised of Proved reserves of $7,339,000 (USD$5,618,000) and Possible reserves of $552,298,000 (USD$422,784,000). The decrease relative to the last QPR report issued in December 2013 was primarily due to a decline in oil prices over the period.

An impairment test was conducted on the oil and gas assets held as at 30 June 2015 and certain assets were identified as being impaired due to their net book values being higher than the discounted reserves valuation. Consequently the book values of certain oil and gas assets have been reduced by $173,352,000 and an impairment expense recognised in profit and loss.

An impairment loss is recognised at reporting date when the balance of an asset's carrying amount exceeds its recoverable amount. The carrying amount of the asset is based upon cost incurred less accumulated depletion. For the purposes of assessing impairment, assets are grouped on a field basis which is the lowest reasonable level for which there are separately independent and identifiable cash inflows from assets or a group of assets.

The recoverable amount is based upon a third-party Qualified Persons Report issued to the Company. The reserve report is derived from the analysis of remaining proven reserves (1P) at a forward strip pricing rate which combines future price predictions from three well-known oil and gas valuation companies. In calculating impairment, the recoverable amount is based upon the estimated cash flows at a discount rate of 10%.

The recoverability of the carrying amount of the undeveloped oil and gas assets is dependent on the successful development and commercial exploitation or sale of the respective areas of interest.

18. TRADE AND OTHER PAYABLES

	Group	
	2015	2014
	$'000	$'000
Current		
Trade payables	18,537	50,919
Accrued employee related costs	80	139
Accrued taxes	6,304	1,249
Accrued interest payable	14,156	9,413
Other payables	323	411
	39,400	62,131
Non-current		
Other payables	1,241	1,124
	1,241	1,124

19. BORROWINGS

	Group	
	2015	2014
	$'000	$'000
Current		
Secured		
Finance lease liabilities	265	551
Total secured current borrowings	265	551
Unsecured		
Convertible notes (refer to note D)		
- convertible note component	174,135	162,108
- embedded derivative component	-	35,036
Total unsecured current borrowings	174,135	197,144
Total current borrowings	174,400	197,695
Non-current		
Secured		
Reserve based lending facility (refer to note A)	-	73,105
First lien senior secured notes (refer to note B)	152,744	-
Second lien senior secured notes (refer to note C)	330,673	263,160
Finance lease liabilities	125	113
Total secured non-current borrowings	483,542	336,378
Unsecured		
Equipment funding loan	-	648
Total unsecured non-current borrowings	-	648
Total non-current borrowings	483,542	337,026
Total borrowings	657,942	534,721

Terms and debt repayment schedule

Terms and conditions of outstanding liabilities were as follows:

Group	Currency	Cash interest rate at 30 June 2015	Year of maturity	Face value	Carrying amount	Face value	Carrying amount
In thousands of dollars $'000				2015	2015	2014	2014
Secured finance lease liabilities	AUD	7.90%	2016	5	4	381	367
Secured finance lease liabilities	USD	6.92%	2015-2017	425	386	319	297
Reserve based lending facility	USD	-	-	-	-	73,105	73,105
First lien senior secured notes	USD	9.625%	2017	163,292	152,744	-	-
Second lien senior secured notes	USD	12.50%	2017	346,176	330,673	281,346	263,160
Unsecured convertible notes	USD	9.00%[1]	2018	174,135	174,135	177,301	162,108
Convertible notes - embedded derivative component	USD	-	2018	-	-	35,036	35,036
Equipment funding loan	USD	-	-	-	-	784	648
Total interest bearing liabilities				684,033	657,942	568,272	534,72

[1] Convertible Notes interest was increased from 7% to 9% on 10 April 2015.

The fair values of current and non-current borrowings approximate their carrying amounts, except for the First Lien Senior Secured Notes which had a fair value at 30 June 2015 of $124,755,000 (USD$95,500,000) (2014: Nil), Second Lien Senior Secured Notes of $45,500,00 (USD$59,438,000) (2014: $311,591,000 (USD$293,488,000)) and the Unsecured Convertible Notes which had a fair value of $93,500,000 (USD$122,142,000) (2014: $203,100,000 (USD$191,300,000)).

Lease liabilities are finance leases for the purchase of motor vehicles. The Group's exposure to interest rate risk is discussed in note 26.

A. Reserve Based Lending Facility

On 13 August 2014, in conjunction with the raising of capital via the 9.625% First Lien Senior Secured Notes, the Group repaid in full the outstanding balance, including accrued interest, of AUD$74,715,000 (USD$69,215,000) on the Key Bank Reserve-Based Lending facility. The facility was cancelled on full repayment.

B. First Lien Senior Secured Notes

On 13 August 2014, the Company's wholly-owned subsidiaries Linc USA GP and Linc Energy Finance (USA), Inc. (the "Issuers"), issued USD$125,000,000 of 9.625% First Lien Senior Secured Notes due 31 October 2017 (the First Lien Senior Secured Notes). The First Lien Senior Secured Notes were issued at 100% of their face value.

The First Lien Senior Secured Notes are fully guaranteed and unconditionally, jointly, and severally, by Linc Energy Resources, Inc. and all of the existing and future US domestic subsidiaries of Linc Energy Resources. The interest on the First Lien Senior Secured Notes is payable on 30 April and 31 October of each year, beginning on 31 October 2014. The First Lien Senior Secured Notes contain affirmative and negative covenants that, among other things, limit the Issuers ability to make investments; incur additional indebtedness or issue preferred stock; create liens; sell assets; enter into agreements that restrict dividends or other payments to restricted subsidiaries; consolidate, merge or transfer all or substantially all of the assets of the Issuers; engage in transactions with the Issuers' affiliates; pay dividends or make other distributions on capital stock or prepay subordinated indebtedness; and create unrestricted subsidiaries. The First Lien Senior Secured Notes also contains events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the First Lien Senior Secured Notes shall become due and payable immediately without any declaration or other act of the holders of the First Lien Senior Notes.

The First Lien Senior Secured Notes are redeemable by the Issuers at any time on or after 30 April 2015, at the redemption prices set forth in the indenture.

C. Second Lien Senior Secured Notes

On 12 October 2012, Linc USA GP and Linc Energy Finance (USA), Inc., issued AUD$258,209,000 (USD$265,000,000) of 12.5% Senior Secured Notes (the "Senior Secured Notes") due 31 October 2017. The Second Lien Senior Secured Notes were issued at 96.402% of their face amount, resulting in net proceeds of AUD$248,918,000 (USD$255,500,000) before discounts and fees.

The interest on the Second Lien Senior Secured Notes is payable on 30 April and 31 October of each year, and began on 30 April 2013. The Notes contain covenants, representations and warranties including limitations on distributions to the Group's non US entities. The Senior Secured Notes are redeemable by the Issuers at any time on or after 30 April 2015, at the redemption prices set forth in the Senior Secured Notes indenture.

On 29 May 2015, the Company announced majority consent had been obtained to amend the terms of the USD$265,000,000 12.5% Second Lien Senior Secured Notes Due 2017 as follows:

- an option for the Company to capitalise the coupon payments due on the Notes in October 2015;
- an option to capitalise the coupon payments due on the Notes in April 2016 upon the Company's oil and gas subsidiary, Linc Energy Resources Inc., receiving net cash proceeds of one or more equity offerings in the aggregate amount of at least USD$50,000,000;
- if the Company elects to capitalise one or both of these coupon payments, the coupon will be calculated at 14%. If the Company elects to cash settle the coupon payments, the coupon will be calculated at the current 12.5% rate; and
- upon the sale of any material assets of the Company's oil and gas subsidiary, Linc Energy Resources Inc, the proceeds will be used to pay down US secured debt in order of priority at the respective call prices contained within the indenture documents at the time of sale.

D. Convertible Notes

On 10 April 2013, Linc Energy Ltd raised AUD$190,142,000 (USD$200,000,000) through the issue of Unsecured Convertible Notes (the Notes) due 10 April 2018.

The Notes are convertible into ordinary shares of Linc Energy Ltd at the election of Note holders at any time on or after 21 May 2013 and ten days prior to 10 April 2018. The Company may make an election to settle in cash by making payment to the relevant Note holders of the cash amount in lieu of delivering or issuing specific amount of shares to such Note holders.

The Company may redeem in whole but not in part the notes on any date on or after 10 April 2015 at their principal amount together with accrued but unpaid interest subject to the ordinary shares trading at a specific level above the conversion price for a specified period of days.

The terms of Notes were further amended on 30 December 2014. The key terms of the amendment were as follows:

- The Company has redeemed USD$50,000,000 of the Notes at par plus accrued interest on 5 January 2015; in return the Note holders' put date is moved back 12 months to 10 April 2016 which may require the Group to redeem some, all or none of the Notes on a single future date being 10 April 2016;
- The Company has the right to repurchase any and all outstanding Notes at a "Make Whole Price" ("MWP") from now through the original 10 April 2015 put date subject to a notification period ("1st Call"). The for the 1st Call means par value of the notes plus current accrued interest plus interest that would have accrued but remains unpaid up to 10 April 2015;
- After 10 April 2015 and until 10 April 2016, the Company has the right to repurchase any and all outstanding Notes at the MWP subject to a notification period ("2nd Call"). The MWP for the 2nd Call means par value of the notes plus current accrued plus interest that would have accrued but remains unpaid up to 10 April 2016); and
- The conversion price of the notes was reset to SGD$1.3411 with immediate effect.

On 10 April 2015, the conversion price was reset to SGD$0.77. The coupon increased from 7% to 9% per annum paid semi-annually commencing on 10 April 2015.

On 4 May 2015, the Company issued 8,446,102 shares on conversion of USD$5,000,000 of the Notes at SGD$0.77 per share.

On 21 May 2015, the Company issued a further 19,763,881 shares on conversion of USD$11,700,000 notes at SGD$0.77 per share. The balance of the Company's convertible notes is at 30 June 2015 is USD$133,300,000.

On 6 August 2015, the Company identified and rectified the issuance in error of 7,052,497 shares of the company as part of the May conversions of the Notes to shares. The extra shares were issued as a result of a calculation error in the Conversion Notice sent to the Company by the Trustee (Citicorp International Limited), relating to the manner in which the USD$50,000,000 redemption in January 2015 was implemented. The Company understands that while payment was made to all Note holders on a pro-rata basis at the time of the redemption, the principal amounts of the Notes held by each Note holder were not adjusted in the note register accordingly. Rather, the Trustee applied a pool factor of 75% to reduce the total value of the outstanding Notes. Accordingly, the nominal value of the Notes on the note register did not change from USD$200,000,000 to USD$150,000,000; instead the amounts due on a future redemption was reduced to reflect the Redemption payment of USD$50,000,000. As a result of the issue referred to above, the recent conversion rights exercised by a Note holder were calculated by the Trustee on the principal amount outstanding to that Note holder without reference to the Redemption. The Company relied on the Conversion Notice provided by the Trustee and consequently, the Note holder was issued 7,052,497 shares to which it was not entitled. A total of 28,209,983 shares were issued on the conversion of the Notes on 21 May and 4 May 2015, when the correct number of shares to be issued on conversion should have been 21,157,486, that is 75% of the original number of shares issued. After the USD$50,000,000, and the conversion of Notes in May 2015, the remaining USD$200,000,000 7% Convertible Notes have an aggregate principal amount outstanding, and redemption value after factoring of 75% of USD$137,475,000, rather than the USD$133,300,000 of face value as previously advised to the market on 21 May 2015.

Group	2015	2014
Convertible Note – Summary of Movements	$'000	$'000
Opening balance	162,108	155,115
Redemption	(61,794)	-
Conversion of notes into shares	(21,169)	-
Unwind of notes	6,851	10,259
Amortisation of fees	-	750
(Gain) / loss on modification	36,286	997
Transfer from embedded derivative	14,441	-
Difference relating to exchange rate fluctuations	37,412	(5,013)
Carrying amount	174,135	162,108
Disclosed in the statement of financial position as		
Current	174,135	162,108
Non-current	-	-

Group	Notes derivative	Notes derivative	Underwriter option derivative[1]
Embedded Derivative Liability – Summary of Movements	2015 $'000	2014 $'000	2014 $'000
Opening Balance	35,036	14,234	1,095
Embedded derivative recognised on inception	-	-	-
(Gain) / loss on modification recognised in fair value through profit and loss	(24,855)	27,900	2,286
Fair value through profit and loss adjustment (excluding tax)	4,260	(7,098)	(3,381)
Transfer to convertible note component[2]	(14,441)	-	-
Closing fair value balance	-	35,036	-
Disclosed in the statement of financial position as			
Current	-	35,036	-
Non-current	-	-	-

[1] The underwriter option derivative lapsed in May 2014.

[2] The embedded derivative is now nil given the Company has the option to cash settle conversion notices. The convertible note liability component is the AUD equivalent of the outstanding note liability of USD$133,300,000.

In accordance with AASB 139 / IAS 39 Financial Instruments, financial instruments are required to be re-valued to fair value at the end of each reporting period and all movements are recognised within other financial instrument expenses in profit and loss. All movements are non-cash and do not form part of the statement of cash flows.

Finance lease liabilities

Finance lease liabilities of the Group are payable as follows:

Group	Future minimum lease payments	Interest	Present Value of minimum lease payments	Future minimum lease payments	Interest	Present Value of minimum lease payments
	2015	2015	2015	2014	2014	2014
	$'000	$'000	$'000	$'000	$'000	$'000
Less than one year	297	32	265	579	28	551
Between one and five years	133	8	125	121	8	113
	430	40	390	700	36	664

20. PROVISIONS

Group	Exploration drilling rehabilitation	Decommissioning and site restoration	Oil & gas rehabilitation	Employee entitlements	Total
	$'000	$'000	$'000	$'000	$'000
Balance at 1 July 2014	100	4,267	43,098	4,246	51,711
Provisions utilised/de-recognised during the period	(300)	-	(836)	(3,794)	(4,930)
Provisions recognised during the period	200	1,656	2,990	5,101	9,947
Effect of exchange rate movements	-	-	9,932	162	10,094
Balance at 30 June 2015	-	5,923	55,184	5,715	66,822
Current	-	-	4,686	4,402	9,088
Non-current	-	5,923	50,498	1,313	57,734

Decommissioning and site restoration

The non-current site restoration provision allows for the decommissioning and restoration of the Group's coal-to-liquids technology development facility at Chinchilla on cessation of all activity at that site.

Oil and gas rehabilitation

The provision relates to the cost of rehabilitating and decommissioning oil field assets and infrastructure such as wells, pipelines and processing facilities.

Employee entitlements

The current employee entitlements provision relates to accrued wages at 30 June 2015, accrued leave entitlements and accrued short-term incentives. The non-current provision relates to accrued long term leave entitlements.

21. DEFERRED REVENUE

	Group	
	2015	2014
	$'000	$'000
Current		
Intellectual Property Licence deferred revenue	3,000	4,211
Non-current		
Intellectual Property Licence deferred revenue	12,250	13,333
Total deferred revenue	15,250	17,544

22. OTHER FINANCIAL LIABILITIES

	Group	
	2015	2014
	$'000	$'000
Current		
Commodity swap contracts (oil hedges)	-	5,766
Non-current		
Commodity swap contracts (oil hedges)	-	2,785
Total other financial liabilities	-	8,551

In the current financial year, commodity swaps are recognised as assets. Refer to note 26 for details of the Group's commodity swap contracts.

23. SHARE CAPITAL

Group	2015	2014	2015	2014
	Number	Number	$'000	$'000
Ordinary shares – fully paid	623,019,273	587,918,910	431,169	396,794
Movements: Ordinary shares				
Opening Balance	587,918,910	519,468,416	396,794	325,388
Shares issued from initial public offering (IPO) and over allotment	-	51,850,000	-	55,499
Costs of IPO, net of tax	-	-	-	(3,962)
Shares issued on conversion of convertible notes	28,209,983	-	21,169	-
Shares issued from call option	-	10,750,000	-	10,978
Shares issued on exercise of options	-	351,198	-	552
Shares issued on vesting of performance rights (a)	6,890,380	5,499,296	13,206	8,339
Closing Balance (b)	623,019,273	587,918,910	431,169	396,794

(a) Information relating to the Linc Energy Ltd Performance Rights Plan, including details of rights granted, vested and lapsed during the financial year is set out in note 30. Please note the Plan is no longer operational.

(b) On 6 August 2015, the Company identified and rectified the issuance in error of 7,052,497 shares as part of the May conversions of the convertible notes into shares. The extra shares were issued as a result of a calculation error in the Conversion Notice sent to the Company by the Trustee. For further details refer to note 19.

Ordinary shares

Ordinary shares entitle the holder to participate in dividends and then proceeds on winding up of the Company in proportion to the number of and amounts paid on the shares held. On a show of hands every holder of ordinary shares present at a meeting in person or by proxy, is entitled to one vote, and upon a poll each share is entitled to one vote. The Company does not have authorised capital and ordinary shares have no par value.

No dividends were declared or paid in the reporting period. (2014: No dividend declared or paid).

Capital risk management

The Group's objectives when managing its ordinary share capital are to ensure its ability to continue as a going concern and to maintain an optimal capital structure and cost of capital appropriate to the stage of development of the Group's business. There are no externally imposed capital requirements on Linc Energy Ltd, however the Company's subsidiary located in Uzbekistan, JSPC Yerostigaz is intermittently subject to government mandated recapitalisation programs for foreign controlled companies. Linc Energy fully participates in these recapitalisations to ensure it maintains or increases its ownership interest in the company. There were no recapitalisations this reporting period (2014: $Nil).

Shares issued on conversion of convertible notes

28,209,983 shares were issued during the year upon conversion of USD$16,700,000 of the Company's USD$200,000,000 Convertible Notes at SGD$0.77.

Shares issued on exercise of employee share options

No shares were issued during the year as a result of the exercise of employee share options (2014: 351,198). All options under the plan have lapsed. The employee option plan is no longer operational.

Shares issued on vesting of performance rights

6,890,380 shares were issued during the year as a result of vested performance rights (2014: 5,499,295). No consideration was received. All employees were transitioned from this plan onto a Short-Term Incentive plan by 30 June 2015.

24. RESERVES

	Group	
	2015	2014
	$'000	$'000
Share-based payments reserve	10,988	20,534
Other reserves	5,309	5,309
Available-for-sale reserve	14,298	995
Foreign currency translation reserve	40,754	24,325
	71,349	51,163

Share-based payments reserve

The share-based payment reserve is used to recognise the fair value of options granted to employees and suppliers. It also recognises the fair value of performance rights issued to employees but not yet vested.

Other reserves

The other reserve represents amounts recognised directly in equity in respect of transactions with other shareholders in Group companies. In 2010, Linc Energy Ltd increased its interest in subsidiary JSPC Yerostigaz from 73% to 91.6% through the purchase of new shares. The transactions with other shareholders amount in the other reserve balance represent the relative transfer of value to / from the non-controlling interest as a result of the transaction.

The other reserve account also contains the remaining balance transferred from the convertible note reserve following the termination of the convertible note facility underwritten by BBY Limited and the redemption of all outstanding notes in September 2009.

Available-for-sale reserve

The available-for-sale reserve represents changes in the fair value and exchange differences arising on translation of investments, such as equities, classified as available-for-sale financial assets. The amounts will only be recognised in profit and loss when the associated assets are sold or impaired.

Foreign currency translation

Exchange differences arising on translation of the foreign controlled entity are taken to the foreign currency translation reserve, as described in note 1(c). The reserve is recognised in profit and loss when the net investment is disposed of.

25. COMMITMENTS AND OPERATING LEASES

Capital expenditure

The company has no capital commitments (2014: Nil) payable within one year of balance date, relating to contractual expenditure for exploration and evaluation.

Operating lease commitments as lessee

Lease commitments contracted but not recognised as liabilities are for non-cancellable operating leases of office premises and office equipment. All finance leases have been recognised in both Current and Non-Current Liabilities. Refer to note 19 for further details.

Commitments in relation to operating leases contracted for at the reporting date but not recognised as liabilities payable:

	Group	
	2015	2014
	$'000	$'000
Within one year	1,714	1,753
Later than one year but not later than five years	4,169	3,887
Later than five years	2,278	2,077
	8,161	7,717

The Group leases a number of office premises under operating leases. Leases typically run for between two and six years with an option to renew for a similar term or continue on a month to month basis. The leases generally provide for additional rental payments that are based on CPI or market reviews with minimum escalation rates.

Tenement commitments

Tenement commitments relate to rent, expenditure commitments and work program commitments contained in the agreements.

	Group	
	2015	2014
	$'000	$'000
Within one year	859	9,105
Later than one year but not later than five years	59,064	26,814
Later than five years	260	1,783
	60,183	37,702

Tenement commitments are not contractual obligations and may be subject to negotiation, deferment or modification. Failure to meet tenement activity or spending commitments within permitted timeframes may result in the relinquishment of parts of, or all of a tenement.

During the year, the Company sold a number of tenements to New Emerald Coal Ltd which were disposed as part of the sale of the coal business to United Queensland Resources Pty Limited.

Port commitments

Port commitments that relate to the take or pay arrangement with Gladstone Port Corporation were disposed as part of the sale of New Emerald Coal Ltd to United Queensland Resources Pty Limited.

	Group	
	2015	2014
	$'000	$'000
Within one year	-	8,981
Later than one year but not later than five years	-	55,337
Later than five years	-	105,545
	-	169,863

26. FINANCIAL INSTRUMENTS

Overview

Overall responsibility for financial risk management rests with the Audit and Risk Management Committee. This committee has responsibility for ensuring the effectiveness of the organisation's financial risk management system, including the approval of associated policies. The Finance group is responsible for the development of policy and the implementation of practices and processes for the management of financial risk.

Credit risk

Credit risk is the risk of financial loss to the Group should a customer or counterparty to a financial instrument default on its contractual obligations and mainly arises from cash and cash equivalents, deposits with banks and financial institutions and trade and other receivables. This risk is managed by depositing funds with credible and independently rated institutions with a minimum S&P credit rating of AA and maximum thresholds for the proportion of investable funds to be held with any one institution. None of the trade and other receivables or other financial assets are deemed to be impaired.

Exposure to credit risk

The carrying amount of financial assets represents the maximum credit exposure. The maximum exposure to credit risk at the reporting date was:

		Group	
		Carrying amount	
		2015	2014
	Note	$'000	$'000
Cash and cash equivalents	10	23,210	48,716
Trade and other receivables	11	39,731	34,568
Other financial assets	14	11,089	-
		74,030	83,284

The maximum exposure to credit risk for cash and cash equivalents at the reporting date held by geographic region was:

	Group	
	Carrying amount	
	2015	2014
	$'000	$'000
Australia	**20,319**	41,700
USA	**2,723**	6,610
Europe	**71**	304
Asia	**38**	55
Africa	**59**	47
Total cash and cash equivalents	**23,210**	48,716

The majority of cash and cash equivalents $20,125,000 (2014: $41,489,000) is being held with two of the Big Four Banks in Australia who have AA credit ratings.

The maximum exposure to credit risk for trade and other receivables at the reporting date held by geographic region was:

	Group	
	Carrying amount	
	2015	2014
	$'000	$'000
Australia	**15,364**	8,403
USA	**23,335**	24,880
Europe	**221**	699
Asia	**807**	576
Africa	**4**	10
Total trade and other receivables	**39,731**	34,568

Trade and other receivables is predominately comprised of USA receivables of $23,335,000 (2014: $24,880,000) primarily from oil and gas revenue which is paid in the following month after delivery.

The Australian balance includes as amount of $7,179,000 (2014: Nil) payable by United Mining Resources Pty Limited for the sale of the coal business due on or before 21 May 2017.

There are no known significant past due or impaired assets as at 30 June 2015 (2014: Nil).

Market risk

Market risk is the risk that changes in market prices such as foreign exchange rates, interest rates and equity prices, will affect the Group's income or the value of its holdings of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimising returns.

Foreign currency risk

The Group is exposed to foreign currency risk to the extent that there is a mismatch between the currencies in which sales, purchases and borrowings are denominated and the respective functional currencies of the Group companies. The establishment and settlement of foreign exchange transactions requires senior finance management approval to minimise exposures to currency fluctuations.

At 30 June 2015 the Group held a material amount of cash and cash equivalents. The distribution of this cash, by currency, is set out in the table below:

	Group	
	Carrying amount	
	2015	2014
	$'000	$'000
Australian Dollar	10,281	16,188
US Dollar	12,669	18,911
Singapore Dollar	99	13,248
South African Rand	61	47
Pounds Sterling	50	181
Uzbekistan Soms	23	14
Polish Zloty	27	127
Total cash and cash equivalents	23,210	48,716

A portion of the Group's available-for-sale financial assets are also exposed to foreign currency risk. $21,703,000 (2014: $9,899,000) of the balance represents investments in companies listed on the London Stock Exchange AIM which are denominated in Pounds Sterling.

The Group is also exposed to foreign currency risk on borrowings that are denominated in a currency other than the functional currency. The convertible notes issued in April 2013 are denominated in USD whereas the functional currency is AUD.

At 30 June 2015, a 10% change in the foreign currency rates would have increased/ (decreased) the convertible notes and embedded derivative in profit or loss by the amounts shown below, assuming all other variables remain constant:

	Group	
	Profit or loss	
	10% Increase	10% Decrease
	$'000	$'000
2015		
Borrowings - convertible note component	15,830	(17,413)
Borrowings - embedded derivatives	-	-
Net sensitivity	15,830	(17,413)
2014		
Borrowings - convertible note component	14,737	(16,211)
Borrowings - embedded derivatives	2,760	(1,911)
Net sensitivity	17,497	(18,122)

Movement of a 10% increase / decrease in foreign currency exchange rates would have no impact on equity (2014: Nil).

Equity price risk

The Group is exposed to equity securities price risk. This arises from the investments in listed companies held by the Group and classified on the statement of financial position as available-for-sale assets. To manage its price risk arising from investments in equity securities, the Group only invests in equity securities approved by the Board of Directors and where the investment provides a strategic advantage to the Group.

At 30 June 2015 the Group held equity securities in a number of listed companies. Changes in the value of these securities are recognised in the available-for-sale reserve in equity. A 5% increase in the value of the investments would have the effect of increasing the available-for-sale reserve in equity by $760,000 (2014: $518,000). A 5% decrease in the value of the investments would have the effect of reducing profit and loss by $50,000 (2014: $50,000).

Commodity price risk

The Group periodically enters into derivative instruments such as swap agreements in an attempt to moderate the effects of fluctuations in commodity prices on the Group's cash flow and to manage exposure to commodity price risk. The Group's commodity derivative instruments generally serve as effective economic hedges of commodity price exposure; however, the Group has elected not to designate its derivatives as hedging instruments. As such, the Group recognises all changes in fair values of its derivative instruments as unrealised gains or losses in profit and loss.

Fair value is calculated using industry-standard models that generally discount projected cash flows to present value using a proprietary discount curve based on published market data.

Group	**Oil (NYMEX WTI)**	
Commodity swaps	**Barrels**	**Weighted Average Hedged price per barrel (USD)**
Financial year 2016	253,612	86.52
Financial year 2017	110,400	86.92

The table below summarises the location and fair value amounts of the Group's derivative instruments reported as assets and liabilities in the consolidated statement of financial position.

	Group	
	2015	2014
	$'000	$'000
Current		
Other financial asset	7,990	-
Other financial liability	-	(5,766)
Non-current		
Other financial asset	3,099	-
Other financial liability	-	(2,785)
Total	11,089	(8,551)

The Group recognised realised gains of $9,176,000 (2014: Losses of $7,679,000) and unrealised gains of $19,767,000 (2014: Losses of $6,126,000) in profit and loss.

	Group Profit or loss	
	10% Increase	10% Decrease
	$'000	$'000
2015		
Current – other financial asset	(1,567)	2,049
Non-current - other financial asset	(733)	250
Net sensitivity	(2,300)	2,299
2014		
Current – other financial liability	(4,706)	4,713
Non-current - other financial liability	(3,647)	3,652
Net sensitivity	(8,353)	8,365

Movement of a 10% increase / decrease in oil prices would have no impact on equity (2014: Nil).

Interest rate risk

Interest rate risk occurs with respect to cash and deposits and borrowings to the extent they are subject to movements in floating interest rates. Cash is usually placed on deposit at fixed interest rates for periods of between 30 and 180 days. At 30 June 2015, the majority of cash held by the Group was held at floating interest rates.

At 30 June 2015, a change in interest rates would have increased/(decreased) financial assets and liabilities and profit and loss by the amounts shown below, assuming all other variables remain constant:

Group	Profit or loss	
	100bp Increase $'000	100bp Decrease $'000
2015		
Financial assets	210	(210)
Financial liabilities	-	-
Borrowings - embedded derivatives	-	-
Net cash flow sensitivity	210	(210)
2014		
Financial assets	292	(292)
Financial liabilities	(731)	731
Borrowings - embedded derivatives	3,079	(2,336)
Net cash flow sensitivity	2,640	(1,897)

Movement of 100 basis points would have no impact on equity at 30 June 2015 or 30 June 2014.

Interest rate risk exposure

The following table sets out the Group's exposure to interest rate risk and the effective weighted average interest rates at the end of the reporting period:

Group	Weighted average effective interest rate per cent	Floating interest rate $'000	Fixed interest rate $'000	Non-interest bearing $'000	Total $'000
2015					
Financial Assets					
Cash and cash equivalents	1.10%	20,233	-	2,978	23,210
Trade and other receivables	2.68%	743	16,159	22,829	39,731
	2.10%	20,976	16,159	25,807	62,941
Financial Liabilities					
Trade and other payables	0.00%	-	-	40,641	40,641
Lease liabilities	6.93%	-	390	-	390
First lien senior secured notes	14.79%	-	152,744	-	152,744
Second lien senior secured notes	14.86%	-	330,673	-	330,673
Unsecured convertible notes	9.00%	-	174,135	-	174,135
	12.52%	-	657,942	40,641	698,583

Group	Weighted average effective interest rate	Floating interest rate	Fixed interest rate	Non-interest bearing	Total
	per cent	$'000	$'000	$'000	$'000
2014					
Financial Assets					
Cash and cash equivalents	1.00%	28,475	-	20,241	48,716
Trade and other receivables	0.51%	716	11,237	22,615	34,568
	0.79%	29,191	11,237	42,856	83,284
Financial Liabilities					
Trade and other payables	1.71%	-	10,789	52,466	63,255
Lease liabilities	6.97%	-	664	-	664
Unsecured equipment funding loan	12.00%	-	648	-	648
Reserve based lending facility	3.39%	73,105	-	-	73,105
Second lien senior secured notes	14.86%	-	263,160	-	263,160
Unsecured convertible notes	7.76%	-	162,108	-	162,108
	9.83%	73,105	437,369	52,466	562,940

Liquidity risk

Liquidity risk exists with respect to the ability of the Group to meet obligations associated with its financial liabilities that are settled by cash. The Group's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meets its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking the Group's reputation. Treasury management including regular monitoring of cash and expenditure levels is undertaken to minimise funding issues. Refer to note 1(a) for further details on liquidity management.

Maturities of financial liabilities

The following are the remaining contractual maturities of the Group's financial liabilities (including estimated interest payments) at the reporting date.

Group	Carrying amount	Contractual cash flows	< 1 year	1 to 2 years	2 to 3 years	> 3 years
	$'000	$'000	$'000	$'000	$'000	$'000
2015						
Trade and other payables	40,641	40,641	39,400	1,241	-	-
Lease liabilities	390	430	297	133	-	-
First lien senior secured notes	152,744	214,461	20,468	20,411	173,582	-
Second lien senior secured notes	330,672	454,657	43,391	43,272	367,994	-
Convertible note[1]	174,135	221,151	189,807	15,672	15,672	-
	698,582	931,340	293,363	80,729	557,248	-
2014						
Trade and other payables	63,255	63,740	62,616	1,124	-	-
Lease liabilities	665	699	578	105	16	-
Unsecured equipment funding loan	648	784	-	784	-	-
Reserve based lending facility	73,105	78,764	2,477	76,287	-	-
Second lien senior secured notes	263,160	404,676	35,168	35,265	35,168	299,075
Convertible note[1]	162,108	271,791	227,201	14,864	14,864	14,862
Other financial liabilities	8,551	8,551	5,766	2,785	-	-
	571,492	829,005	333,806	131,214	50,048	313,937

[1] The contractual cash flows contain the embedded derivative. From April 2016 the convertible notes can be settled in either cash or shares.

Measurement of fair values

Fair Value Hierarchy

The fair value of financial assets and liabilities approximate their carrying values. The table below analyses financial instruments carried at fair value, by valuation method. The different levels have been defined as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets and liabilities
- Level 2: inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices)
- Level 3: inputs for the asset of liability that are not based on observable market data (unobservable inputs).

Group	Level 1 $000	Level 2 $000	Level 3 $000	Total $000
2015				
Available-for-sale assets	23,120	-	-	23,120
Other financial assets (US oil and gas commodity swaps and options)	-	11,089	-	11,089
Borrowings – Embedded derivatives	-	-	-	-
	23,120	11,089	-	34,209
2014				
Available-for-sale investments	11,316	-	-	11,316
Other financial liabilities	-	(8,551)	-	(8,551)
Borrowings – Embedded derivatives	-	-	(35,036)	(35,036)
	11,316	(8,551)	(35,036)	(32,271)

The Group has embedded derivatives as part of the Convertible Notes issued in April 2013 and subsequently modified in December 2013 and December 2014. In order to determine the fair value of the embedded derivatives, management used a Monte-Carlo valuation model. Key assumptions adopted for the valuation model up to modification of the Convertible Notes in December 2014 included: a coupon rate of 7% per annum up to 10 April 2015, coupon rate of 9% per annum after 10 April 2015, initial conversion price of SGD$1.3411, underlying share price at spot, underlying spot rate USD/SGD, as well as adjusting for volatility, risk free interest rate (USD) and credit / liquidity spread.

The following table shows a reconciliation from the beginning balances to the ending balances for the fair value measurements in Level 3 of the fair value hierarchy:

Group Embedded Derivative Liability – Summary of Movement	Notes derivative 2015 $'000	Notes derivative 2014 $'000	Underwriter option derivative 2014 $'000
Opening Balance	35,036	14,234	1,095
Gain / loss on modification recognised in fair value through profit and loss	(24,855)	27,900	2,286
Fair value through profit and loss adjustment (excluding tax)	4,260	(7,098)	(3,381)
Transfer to convertible note component	(14,441)		
Closing fair value balance	-	35,036	-

The underwriter embedded derivative lapsed in May 2014.

Level 3 fair values sensitivity analysis

For the fair values of embedded derivatives, reasonably possible changes at the reporting date to one of the significant unobservable inputs, holding other inputs constant, would have the following effect:

Group	Profit or Loss (excluding tax)	
	Increase $000	Decrease $000
2015		
Change of 10c in share price	-	-
2014		
Change of 10c in share price	3,185	(1,062)

27. OPERATING SEGMENTS

Reportable segments

The Group has three reportable segments. The reportable segments are:

- Oil and Gas – exploration, development and production of traditional oil and gas assets in North America;
- Clean Energy – development and commercialisation of Coal-to-Liquids (CTL) processes through the combined utilisation of Underground Coal Gasification (UCG) and Gas to Liquids (GTL) technologies; and
- Shale oil (SAPEX) – exploration of the Group's petroleum exploration tenements in South Australia.

During the financial year the Group's Coal segment was classified as a discontinued operation as it was sold to United Queensland Resources Pty Limited in February 2015 and approved at the Extraordinary General Meeting held on 14 May 2015.

The divisional managers are accountable for their division's financial performance and maintain regular contact with the chief operating decision maker (CODM). The Group's Chief Executive Officer who is the CODM reviews internally generated management reports on at least a monthly basis.

Information regarding the results of each reportable segment is included in the table on the following page:

	Oil & Gas		Coal (Discontinued)		Clean Energy		Shale Oil (SAPEX)		Corporate/unallocated		Total	
	2015 $'000	2014 $'000	2015 $'000	2014 $'000	2015 $'000	2014 $'000	2015 $'000	2014 $'000	2015 $'000	2014 $'000	2015 $'000	2014 $'000
External revenues	81,810	141,627	-	-	5,976	6,763	-	-	-	-	87,786	148,390
Interest revenue	2	17	-	1	4	-	20	10	3,916	1,196	3,942	1,224
Finance expenses	(64,370)	(42,761)	-	-	-	-	-	-	(27,787)	(26,545)	(92,157)	(69,306)
Depreciation, amortisation & depletion	(88,976)	(76,368)	-	-	(2,886)	(3,060)	(1)	-	(1,026)	(1,348)	(92,889)	(80,776)
Reportable segment profit / (loss) before income tax	(272,454)	(87,952)	(43,882)	(9,246)	(14,917)	(27,217)	(838)	(1,463)	36,901	(100,188)	(295,190)	(226,066)
Material non-cash items of income or expense:												
Gain on disposal of discontinued operation	-	-	10,134	-	-	-	-	-	-	-	10,134	-
Gain on sale of available-for-sale assets	-	-	-	-	-	-	-	-	433	-	433	-
Share-based payment expense	-	-	-	-	-	-	-	-	(3,520)	(9,203)	(3,520)	(9,203)
Impairment expense	(173,351)	(34,390)	(41,180)	-	-	(5,469)	-	-	(3,768)	-	(218,299)	(39,859)
Reportable segment non-current assets	461,461	574,018	-	43,932	102,270	92,777	154,148	136,870	23,495	13,822	741,374	861,419
Total reportable segment assets	481,585	593,680	-	43,986	105,672	96,714	154,201	136,907	69,851	71,684	811,309	942,971
Goodwill	-	-	-	-	1,292	1,292	-	-	-	-	1,292	1,292
Capital expenditure (net of rebates)	40,760	126,706	826	3,400	956	2,471	17,280	1,390	461	529	60,283	134,496

Geographical Segments

The worldwide operations of the Group are managed from the Brisbane head office, but the Group's operations are located in five principal locations: Australia, North America, Asia, Europe and South Africa. In Australia, the Group operates in Queensland and South Australia. In North America the Group operates in Wyoming, Montana, Texas and Alaska. In Asia, the operations are at Yerostigaz in Angren, Uzbekistan. In Europe the Group operates from Poland and in South Africa the Group operates in Johannesburg. The Group has closed offices during the year in London, Denver, Casper, Anchorage and Singapore.

In presenting information on the basis of geographical segments, segment revenue is based on the geographical location of customers. Segment assets are based on the geographical location of the assets.

	2015		2014	
	Revenues	Non-Current Assets	Revenues	Non-Current Assets
	$'000	$'000	$'000	$'000
Australia	-	208,247	-	228,499
USA	81,810	528,331	141,627	626,682
Asia	3,058	1,536	2,658	2,504
Europe	12	3,244	564	3,712
South Africa	2,906	16	3,466	22
Canada	-	-	75	-
	87,786	741,374	148,390	861,419

In the USA, all oil produced from the Glenrock fields in Wyoming is currently delivered to and sold to a third party refiner. On the Gulf Coast (Texas and Louisiana) oil is sold to two third party refineries. In Asia, all syngas produced at Yerostigaz is currently sold to the Angren power station which is a State-owned utility company.

28. CONTINGENT ASSETS AND LIABILITIES

CONTINGENT ASSETS

Partial Block Extraction royalty

In February 2015, the Company sold its proprietary Partial Block Extraction (PBE) technology to Underground Extraction Technologies Pty Ltd (UET). As part of this transaction, the Company is entitled to receive AUD$0.20 per tonne of Run Of Mine (ROM) coal in perpetuity for extracted coal from any mine through the exploitation of the PBE system excluding coal extracted by the Company, New Emerald Coal Ltd (NEC) or any affiliate of either the Company or NEC or third party licensed by any of them.

New Emerald Coal royalty

On 12 February 2015, the Company entered into a Revenue Sharing Agreement with New Emerald Coal Ltd (NEC) in respect to exploitation of certain coal tenements by NEC and / or its affiliates. Under the agreement NEC will pay an indexed royalty per product of tonne of coal produced from the Blair Athol mine (USD$0.50) which is subject to completion by NEC, Teresa (USD$1.00) and Pentalnd (USD$1.00) until production ceases on the tenements. This agreement survives any change in control affecting NEC or any of its affiliates

CONTINGENT LIABILITIES

Acquisition of Powder River Basin coal leases from Gastech Inc.

On 24 December 2009 the Group announced that it had acquired an additional 81,268 acres of Powder River Basin (Wyoming) and Williston Basin (Montana) coal lease tenements from Gastech Inc. and Wold Oil Properties Inc respectively. Gastech Inc. retains a royalty interest in an amount equal to one quarter of the coal production royalties payable to the State of Wyoming under the Wyoming leases, but not greater than 2%.

Department of Environment and Heritage Protection Financial Assurance

During the year ended 30 June 2015, the Company received a decision on the application to amend or discharge the financial assurance bond required to be held with the DEHP in relation to MDL's and PFL's in Chinchilla. This decision requires the bond to be increased from $3.9million to $29.2million. While this decision accepts a number of the Company's assertions in relation to the costs associated with rehabilitation, the main differences relate to methodology of and costs associated with processing water and impacted soil. The Company believes that the methodology applied in calculating the rehabilitation costs is consistent with relevant regulations and it intends to apply this methodology in the rectification of the MDL's and PFL's. The Company has applied for stay of the decision with the DEHP which has been ratified. The Company is therefore not required to provide any increased financial assurance until the litigation appeal with the lands court is finalised.

Department of Environment and Heritage Protection Notice

In April 2014, the Company was served with a Complaint and Summons by the Queensland Department of Environment and Heritage Protection (DEHP) charging the Company with four indictable offences alleging the Company wilfully and unlawfully caused serious environmental harm during the operation of its UCG Demonstration Facility at Chinchilla on a date or dates unknown between July 2007 and February 2012, being the operation of gasifiers 2, 3 and 4, in breach of the Environmental Protection Act 1994 (EP Act). The Company considers these allegations to be without merit, although there can be no assurance that the Company will not be found guilty of the offences.

In January 2015, DEHP amended the four charges to remove the allegation the Company intentionally caused the alleged serious environmental harm.

In June 2015, DEHP served a further Complaint and Summons charging the Company with a fifth indictable offence alleging the Company wilfully and unlawfully caused serious environmental harm during the operation of its UCG Demonstration Facility at Chinchilla on a date or dates unknown between October 2011 and December 2013, being the operation of gasifier 5.

The maximum aggregate financial penalty under the EP Act for the 5 indictable offences for a corporation is approximately $18,406,250 ($3,681,250 per offence). The Company is confident of defending itself against these charges. In the event the Company is unsuccessful and was to be found guilty of all 5 charges, the Company may have to pay a nominal fine, undertake some form of rehabilitation and engage in regular compliance monitoring and reporting to DEHP, which should not have a material impact on the Company's operations.

The directors are not aware of any other contingent assets or liabilities. As at 30 June 2015, the maximum amount quantifiable in relation to litigation and associated legal fees that had not already been provided or accrued for in the financial statements was $18,406,250 (2014: $9,200,000).

29. SUBSIDIARIES

The consolidated financial statements incorporate the assets, liabilities and results of the following subsidiaries:

Entity	Balance Date	Country of incorporation	Class of shares	2015 %	2014 %
JSPC Yerostigaz	31 Dec[1]	Uzbekistan	Ordinary	91.6	91.6
Better Air LLC	31 Dec[1]	Uzbekistan	Ordinary	-	100
SAPEX Limited	30 Jun	Australia	Ordinary	100	100
Linc Heavy Oil Australia Pty Ltd (formerly Linc Carbon Solutions Pty Ltd)	30 Jun	Australia	Ordinary	100	100
Linc Energy Operations (Canada) Ltd	30 Jun	Canada	Ordinary	100	-
Linc Energy Operations Pty Ltd	30 Jun	Australia	Ordinary	100	100
New Emerald Coal Ltd (formerly Teresa Coal Pty Ltd)	30 Jun	Australia	Ordinary	-	100
New Emerald Coal Operations Pty Ltd	30 Jun	Australia	Ordinary	-	100
New Emerald Coal 1 Pty Ltd	30 Jun	Australia	Ordinary	-	100
New Emerald Coal 2 Pty Ltd	30 Jun	Australia	Ordinary	-	100
Linc Energy Heavy Oil Technology Pty Ltd (formerly New Pentland Coal Pty Ltd)	30 Jun	Australia	Ordinary	100	100
Linc Energy (Africa) Pty Ltd (formerly Linc Energy Property Pty Ltd)	30 Jun	Australia	Ordinary	100	100
Linc Energy GP1 Pty Ltd	30 Jun	Australia	Ordinary	100	100
Linc Energy GP2 Pty Ltd	30 Jun	Australia	Ordinary	100	100
Linc Energy Operations (Africa) Proprietary Limited	28 Feb	Africa	Ordinary	100	100
Linc USA GP	30 Jun	USA	Ordinary	100	100
Linc Energy Finance (USA), Inc	30 Jun	USA	Ordinary	100	100
Linc Clean Energy, Inc	30 Jun	USA	Ordinary	100	100
Linc Energy (Wyoming), Inc	30 Jun	USA	Ordinary	100	100
Linc Energy (Alaska), Inc	30 Jun	USA	Ordinary	100	100
Linc Energy Operations Inc.	30 Jun	USA	Ordinary	100	100
Linc Energy Resources, Inc	30 Jun	USA	Ordinary	100	100
Linc Energy Petroleum (Wyoming), Inc	30 Jun	USA	Ordinary	100	100
Linc Gulf Coast Petroleum, Inc	30 Jun	USA	Ordinary	100	100
Paen Insula Holdings, LLC	30 Jun	USA	Ordinary	100	100
Diasu Holdings, LLC	30 Jun	USA	Ordinary	100	100
Diasu Oil & Gas Company, Inc	30 Jun	USA	Ordinary	100	100
Linc Energy Petroleum(Louisiana), LLC	30 Jun	USA	Ordinary	100	100
Linc Alaska Resources, LLC	30 Jun	USA	Ordinary	100	100
Renaissance Umiat, LLC	30 Jun	USA	Ordinary	84.5	84.5
Linc Energy (Europe) Ltd	30 Jun	United Kingdom	Ordinary	100	100
Linc Energy Operations Ltd	30 Jun	United Kingdom	Ordinary	100	100
Linc Energy (Africa) Ltd (formerly Linc Energy (UK) Ltd)	30 Jun	United Kingdom	Ordinary	100	100
Linc Energy (Poland) (sp.z.o.o.)	30 Jun	Poland	Ordinary	100	100
Linc Energy (Poland Holding Company) sp.z.o.o.	30 Jun	Poland	Ordinary	100	100
Linc Energy (Poland Operations) sp.z.o.o.	30 Jun	Poland	Ordinary	100	-
Linc Energy (Singapore) Pte. Ltd	30 Jun	Singapore	Ordinary	100	100

[1] Companies incorporated in Uzbekistan must have a balance date of 31 December.

KPMG is the auditor of all significant Australian incorporated subsidiaries and the parent. Other member firms of KPMG International are auditors of significant foreign-incorporated subsidiaries. Subsidiaries not audited by KPMG and the member firms of KPMG International are not considered significant as defined under the Singapore Exchange Limited Listing Manual if its net tangible assets represent 20% or more of the Group's consolidated net tangible assets, or if its pre-tax profits accounts for 20% or more of the Group's consolidated pre-tax profits.

30. SHARE-BASED PAYMENTS

Employee option plan

The establishment of the Linc Energy Ltd Employee Option Plan was approved by Shareholders at the 2005 Annual General Meeting. This plan was replaced by the Performance Rights Plan with effect from the 2009 Annual General Meeting. However the option plan continued to operate until all outstanding options expired. Options were granted at the discretion of the Board in accordance with the rules of the plan and all staff employed by the Company or its subsidiaries were eligible to participate in the plan.

As determined by the Board, a minimum continuous period of employment (usually twelve months) with the Company or any of its subsidiaries was served prior to the first exercise date, which fell on 31 December annually. The option exercise price was set at the discretion of the Board, but was generally the ten day volume weighted average price (VWAP) of Linc Energy Ltd shares traded on the Australian Securities Exchange following commencement of employment with the Group. Subject to ongoing employment by the Company or any of its subsidiaries, options were exercisable over three consecutive years from the initial exercise date, with one-third of the total options awarded exercisable each year.

Options granted under the plan carried no dividend or voting rights. When exercisable, each option was convertible into one ordinary share.

The assessed fair value at grant date was independently determined using a Black-Scholes option pricing model that took into account the exercise price, the term of the option, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield and the risk free interest rate for the term of the option.

No options have been granted since the Company moved to the Singapore Stock Exchange.

No options were granted or exercised (2014: 351,198) during the reporting period. All options under the plan have now lapsed with the plan no longer operating.

Financial year of grant	Expiry date	Exercise price range	Balance at start of year	Granted	Exercised or transferred	Forfeited[1]	Balance at end of year	Exercisable at end of the year
2015		$	Number	Number	Number	Number	Number	Number
30 Jun 2010	31 Dec 14	1.50 to 1.79	203,332	-	-	(203,332)	-	-
30 Jun 2009	31 Dec 14	3.16	78,000	-	-	(78,000)	-	-
Total			281,332	-	-	(281,332)	-	-
Weighted average exercise price			1.99	-	-	1.99	-	-

[1] Forfeited includes options that have lapsed or cancelled due to termination.

Financial year of grant	Expiry date	Exercise price range	Balance at start of year	Granted	Exercised or transferred	Forfeited[1]	Balance at end of year	Exercisable at end of the year
2014		$	Number	Number	Number	Number	Number	Number
30 Jun 2010	31 Dec 14	1.45 to 1.79	573,331	-	(66,666)	(303,333)	203,332	203,332
30 Jun 2009	31 Dec 14	0.59 to 3.16	1,119,194	-	(32,866)	(1,008,328)	78,000	78,000
30 Jun 2008	31 Dec 13	0.60 to 2.55	486,999	-	(251,666)	(235,333)	-	-
Total			2,179,524	-	(351,198)	(1,546,994)	281,332	281,332
Weighted average exercise price			1.86	-	0.92	2.05	-	1.99

[1] Forfeited includes options that have lapsed or cancelled due to termination.

Performance Rights Plan

The establishment of the Linc Energy Employee Performance Rights Plan was approved by Shareholders at the 2009 Annual General Meeting. The Performance Rights Plan sought to align the interest of eligible employees with the future growth and development of the Company. The provision for the Performance Rights Plan to vest in multiple tranches over multiple years provided the balance between the objectives of attracting and retaining high performing employees and aligning the interests of these employees with the shareholders in the long term.

The number of rights granted was determined at the discretion of the Board and based on a formula taking into account an employee's base salary and the Company's share price at the time of grant. The Rights typically vested in in either three or four equal tranches over a period of three and half to four and half years, with the first tranche vesting twelve months from the successful completion of probation period. Rights were granted at no cost to the participant and may have included non-market-based performance conditions. The rights automatically converted to shares on the vesting date provided all vesting conditions were met.

The fair value of the rights was determined based on Linc's closing share price at the date of grant.

Rights granted under the plan carried no dividend or voting rights until they converted to ordinary shares. 1,987,564 Performance Rights were granted during the period (2014: 4,579,974).

During the financial year, all employees were transitioned from the Performance Rights Plan onto a Short-Term Incentive Plan. No rights remain outstanding at the date of this report. This plan is no longer operating.

Performance rights granted

Set out below is a summary of performance rights granted during the year:

Financial year of grant	Balance at start of year	Granted	Vested and converted into equity	Vested and paid in cash	Forfeited[1]	Balance at end of year
2015	Number	Number	Number	Number	Number	Number
30 June 2015	-	1,987,564	(1,964,592)	(5,743)	(17,229)	-
30 June 2014	1,462,525	-	(386,915)	-	(1,075,610)	-
30 June 2013	6,522,916	-	(3,018,634)	(8,392)	(3,495,890)	-
30 June 2012	1,602,717	-	(1,122,664)	-	(480,053)	-
30 June 2011	499,469	-	(397,575)	-	(101,894)	-
Total	10,087,627	1,987,564	(6,890,380)	(14,135)	(5,170,676)	-

[1] Forfeited rights are due to employees ceasing employment or transitioning to the short-term incentive plan.

Financial year of grant	Balance at start of year	Granted	Vested and converted into equity	Vested and paid in cash	Forfeited[1]	Balance at end of year
2014	Number	Number	Number	Number	Number	Number
30 June 2014	1,462,525	2,887,555	(1,139,818)	-	(285,212)	1,462,525
30 June 2013	6,522,916	1,671,945	(1,716,314)	(8,392)	(1,283,327)	6,522,916
30 June 2012	1,598,283	20,474	(841,302)	-	(737,619)	1,602,717
30 June 2011	499,473	-	(1,657,930)	-	(110,263)	499,469
30 June 2010	152,135	-	(143,932)	-	(8,203)	-
Total	13,439,969	4,579,974	(5,499,296)	(8,392)	(2,424,624)	10,087,627

[1] Forfeited rights are due to employees ceasing employment.

Expenses arising from share-based payment transactions

Expenses arising from share-based payment transactions recognised during the period totalled $3,520,000 (2014: $9,203,000).

31. RELATED PARTY TRANSACTIONS

	2015 $	2014 $
Key management personnel compensation		
Short-term employee benefits	5,733,704	6,647,071
Post-employment benefits	443,765	362,697
Termination benefits	88,949	256,915
Long-term benefits	34,324	15,932
Share-based payments	32,243	2,008,674
	6,332,985	9,291,289

Transactions with key management personnel and directors

Directors, Mr Craig Ricato, Mr Peter Bond, Mr Kenneth Dark, Mr Lim Ah Doo Lim and Mr Koh Ban Heng hold positions in other entities that result in them having control or significant influence over the financial and operating policies of those entities. These entities have transacted with the Group in the reporting period. The terms and conditions of the transactions with these entities were no more favourable than those available, or which might reasonably be expected to be available, on similar transactions to non-key management personnel related entities on an arm's length basis.

The aggregate value of transactions and outstanding balances relating to key management personnel and entities over which they have control of significant influence were as follows:

Receivable transactions with key management personnel and directors

			Transactions value year ended 30 June		Balance outstanding as at 30 June	
Key Management Person	Related party entity	Transaction	2015 $	2014 $	2015 $	2014 $
Peter Bond	Peter Bond	Reimbursement of expenses	84,847	3,314	65,016	3,314
	Bond Air Charters Pty Ltd	Refund of prepaid[1] chartered flights	682,075	-	682,075	-
	Bond Bros Contracting Pty Ltd	Reimbursement of expenses	-	-	3,201	3,201
Kenneth Dark	KE & SL Dark	Loan	-	8,839	-	-
Peter Bond	Hillgrove Pty Ltd	Loan	-	10,749	-	-

* All Values are GST Inclusive if applicable

[1] The Company expects to receive a repayment of $682,075 from Bond Air Charters Pty Ltd, a related party of Peter Bond, for the return of unused charter flight funds that were prepaid in advance in May 2014.

Payable transactions with key management personnel and directors

			Transactions value year ended 30 June		Balance outstanding as at 30 June	
Key Management Person	Related party entity	Transaction	2015 $	2014 $	2015 $	2014 $
Craig Ricato	Executive Management Services Discretionary Trust	Executive services	1,902,923	1,376,571	-	-
Peter Bond	Bond Bros Contracting Pty Ltd	Executive services	2,200,000	1,650,000	-	-
	Bond Air Charters Pty Ltd	Chartered flights	-	726,943[1]	-	-
	Rough Diamond Media Pty Ltd	Film editing and production	3,273	10,054	-	-
	Newtron Pty Ltd		-	660,000	-	-
Kenneth Dark	KE & SL Dark	Director Fees	223,737	208,625	39,402	17,990
Lim Ah Doo	Lim Ah Doo	Director Fees	254,650	171,605	-	23,616
Koh Ban Heng	Koh Ban Heng	Director Fees	187,085	139,318	-	19,173

* All Values are GST Inclusive if applicable

[1] Recognised as prepaid expenses at 30 June 2014 in the statement of financial position.

Rights over equity instruments

The movement during the reporting period in the number of rights to ordinary shares in Linc Energy Ltd held, directly, indirectly or beneficially, by each key management person, including their related parties, is as follows:

Name	Balance at start of year[1]	Number of rights granted as compensation during year	Vested during the year	Forfeited during the year	Unvested balance at end of the year[2]
	Number	Number	Number	Number	Number
2015					
Peter Bond[3]	15,169	-	(5,912)	(9,257)	-
Jon Mathews	125,000	-	(125,000)	-	-
Michael Mapp	-	2,000	(2,000)	-	-
Stuart Jones	800,000	-	(200.000)	(600,000)	-
	940,169	2,000	(332,912)	(609,257)	-
2014					
Peter Bond[3]	11,824	3,345	-	-	15,169
Jon Mathews	250,000	-	(125,000)	-	125,000
Stuart Jones	800,000	-	-	-	800,000
Donald Schofield	-	200,000	-	(200,000)	-
Scott Broussard	900,000	-	-	(900,000)	-
Bill Young	91,220	-	(22,805)	-	68,415
Adam Bond	900,100	-	(250,100)	-	650,000
Michael Mapp	1,000,000	473,732	(824,609)	(649,123)	-
Carl Fisher	798,000	-	(223,000)	-	575,000
	4,751,144	677,077	(1,445,514)	(1,749,123)	2,233,584

[1] Or date commenced as a key management person.
[2] Or date ceased to be a key management person
[3] Mr Peter Bond's rights are held by related parties.

Movements in shares

The movement during the reporting period in the number of ordinary shares in Linc Energy Ltd held, directly, indirectly or beneficially, by each key management person, including their related parties, is as follows:

	Balance at the start of the year[1]	Additions	Disposals	Balance at the end of the year[2]
	Number	Number	Number	Number
2015				
Peter Bond[3]	202,621,028	5,912	-	202,626,940
Craig Ricato	1,000,561	-	-	1,000,561
Kenneth Dark[4]	1,290,000	-	-	1,290,000
Jon Mathews[5]	378,000	125,000	-	503,000
Ong Tiong Soon[6]	136,000	-	-	136,000
Michael Mapp	732	2,000	-	2,732
Stuart Jones	-	200,000	(200,000)	-
Janelle van de Velde	184,863	-	-	184,863
	205,611,184	332,912	(200,000)	205,744,096
2014				
Kenneth Dark[4]	2,037,000	-	(747,000)	1,290,000
Peter Bond[3]	202,621,028	-	-	202,621,028
Jon Mathews[5]	250,000	128,000	-	378,000
Craig Ricato	2,501,561	-	(1,501,000)	1,000,561
Donald Schofield	330,000	-	-	330,000
Janelle van de Velde	184,863	-	-	184,863
Scott Broussard	100,000	-	-	100,000
Bill Young	-	22,805	-	22,805
Adam Bond	100,000	250,100	(65,000)	285,100
Michael Mapp	-	824,609	(823,877)	732
Carl Fisher	-	223,000	(223,000)	-
	207,634,480	1,448,514	(3,359,877)	206,213,089

[1] Or date commenced being a key management person
[2] Or date ceased to be a key management person
[3] Mr Peter Bond's shares are held via Newtron Pty Ltd or its nominees. 5,912 share additions are held by a related party.
[4] Mr Kenneth Dark's shares are held by related parties.
[5] A portion of Mr Jon Mathews shares are held by related parties.
[6] Mr Ong Tiong Soon's shares are held via Asia Trade Investment Ltd.

Mr Lim Ah Doo and Mr Koh Ban Heng did not hold Linc Energy shares while they were Non-Executive Directors.

Other related party interests

Hillgrove Pty Ltd, a company controlled by Executive Chairman, Peter Bond owns a 5.15 per cent (2014: 5.45 per cent) interest in Powerhouse Energy Group plc, an entity Linc Energy Ltd also holds a 7.30 per cent (2014: 7.73 per cent) interest in. Mr P Bond is not involved in discussions or board decisions relating to the Company's investment in Powerhouse Energy.

32. REMUNERATION OF AUDITORS

During the year the following fees were paid or payable for services provided by the auditor of the Group.

	Group	
	2015	2014
	$	$
Audit services		
KPMG Australia	497,150	414,900
Overseas KPMG firms	726,776	547,267
	1,223,926	962,167
Services other than statutory audit:		
KPMG Australia:		
IT advisory services	-	20,500
Assurance services	-	498,736
Other services	23,000	44,775
	23,000	564,011
Overseas KPMG firms:		
Assurance services	-	291,680

33. PARENT ENTITY DISCLOSURE

As at and throughout the financial year ended 30 June 2015 the parent entity of the Group was Linc Energy Ltd:

	Company	
	2015	2014
	$'000	$'000
Result of the parent entity		
Profit/(loss) for the period[1]	(160,621)	(114,751)
Other comprehensive income	13,303	(3,432)
Total comprehensive income / (loss) for the period	(147,318)	(118,183)
Financial position of the parent entity at year end		
Current assets	43,975	53,578
Total assets	470,654	627,729
Current liabilities	186,191	210,971
Total liabilities	205,677	229,701
Total equity of the parent entity comprising of:		
Share capital	431,169	396,794
Share-based payment reserve	10,988	20,534
Available-for-sale reserve	14,298	995
Other reserves	5,274	5,274
Retained earnings	(196,752)	(25,569)
Total Equity	264,977	398,028

[1] The loss for the period includes the loss from discontinued operations of ($43,882,000).

The loss also includes an impairment expense of $160,000,000 for the parent's investment in the US subsidiaries.

Parent entity contingencies

The Directors are not aware of any other contingent liabilities other than as set out in note 28.

Parent entity capital commitments for the acquisition of intangible assets or property, plant and equipment

As at the 30 June 2015 the parent entity had no capital commitments for the acquisition of tangible and intangible assets.

Parent entity guarantees in respect of debts of its subsidiaries

The parent entity does not guarantee the debts of its subsidiaries (30 June 2014: Nil). The Parent entity has provided a letter of financial support to the Directors of SAPEX Limited and Linc Energy's US and UK subsidiaries.

Parent entity guarantees in respect of former subsidiary

The parent entity has guaranteed ongoing commitments on behalf of New Emerald Coal Ltd in relation to the purchase of Blair Athol which will not be removed until the transaction is completed.

34. SUBSEQUENT EVENTS

Matters subsequent to the end of the financial year were as follows:

Cessation of Independent Non-Executive Director

On 31 July 2015, Independent Non-Executive Director, Mr Jon Mathews resigned to commence his retirement.

Appointment of Independent Non-Executive Directors

On 3 August 2015, the Company appointed two Independent Non-Executive Directors, Mr Mark Leahy and Mr James (Mun Foong) Yip. Mr Mark Leahy has been appointed Lead Independent Director, Chairman of the Audit and Risk Management Committee and member of the Nominating and Remuneration Committee. Mr James (Mun Foong) Yip has been appointed Chairman of the Nominating and Remuneration Committee and member of the Audit and Risk Management Committee.

Issued Capital

On 6 August 2015, the Company voided the issuance of a total of 7,052,497 shares that were issued in error on 21 May 2015 and 4 May 2015 as part of the conversion of USD$16,700,000 face amount of the Company's USD$200,000,000 7% Convertible Notes due 2018. The extra shares were issued as a result of a calculation error in the Conversion Notice sent to the Company by the Trustee (Citicorp International Limited) in May 2015, relating to the manner in which the USD$50,000,000 redemption in January 2015 was implemented. Following the voidance of shares, the number of issued and paid-up shares in the capital of the Company has decreased to 615,966,776 equating to $425,545,587 while the Convertible Notes have a carrying value of USD$137,475,000. The effect on earnings per share would have been as follows:

	Current	Revised
Profit / (loss) attributable to the ordinary equity holders of the Company:		
Basic earnings / (loss) per ordinary share (AUD cents per share)	(49.19)	(49.26)
- weighted average number of shares	595,302,273	594,411,730
Fully diluted earnings / (loss) per ordinary share (AUD cents per share)	(49.19)	(49.26)
- weighted average number of shares	595,302,273	594,411,730

DIRECTORS' DECLARATION FOR THE YEAR ENDED 30 JUNE 2015

In the Directors' opinion:

1 (a) The consolidated financial statements and notes, set out on pages 67 to 129, are in accordance with the *Corporations Act 2001,* including:

- I. giving a true and fair view of the Group's financial position as at 30 June 2015 and of its performance, for the financial year ended on that date; and
- II. complying with Australian Accounting Standards and the Corporations Regulations 2001; and
- III. complying with Singapore Exchange SGX Mainboard Rule 1207 (5); and

(b) there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable

2 The Directors have been given the declarations by the Chief Executive Officer and Chief Financial Officer required by Section 295A of the *Corporations Act 2001* for the financial year ended 30 June 2015.

3 The Directors draw attention to Note 1(a) to the consolidated financial statements, which includes a statement of compliance with International Financial Reporting Standards.

This declaration is made in accordance with a resolution of the Directors.

Craig Ricato

Director

Brisbane

25 September 2015

Independent auditor's report to the members of Linc Energy Ltd

We have audited the accompanying financial report of Linc Energy Ltd (the company), which comprises the consolidated statement of financial position as at 30 June 2015, and the consolidated statement of profit or loss and other comprehensive income, consolidated statement of changes in equity and consolidated cash flow statement for the year ended on that date, notes 1 to 34, comprising a summary of significant accounting policies and other explanatory information, and the Directors' declaration of the Group, comprising the Company and the entities it controlled at the year's end or from time to time during the financial year. We have also audited the accompanying statement of financial position of the Company as at 30 June 2015.

Directors' responsibility for the financial report

The Directors of the Company are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards, Corporations Act 2001 and the Singapore Exchange SGX Mainboard Rule 1207(5) and for such internal control as the Directors determine is necessary to enable the preparation of the financial report that is free from material misstatement whether due to fraud or error. In note 1(a), the Directors also state, in accordance with Australian Accounting Standard AASB 101 *Presentation of Financial Statements* and IAS 1 *Presentation of Financial Statements* that the financial statements of the Group comply with International Financial Reporting Standards.

Auditor's responsibility

Our responsibility is to express an opinion on the financial report based on our audit. We conducted our audit in accordance with Australian Auditing Standards. These Auditing Standards require that we comply with relevant ethical requirements relating to audit engagements and plan and perform the audit to obtain reasonable assurance whether the financial report is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial report. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the financial report, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation of the financial report that gives a true and fair view in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by the Directors, as well as evaluating the overall presentation of the financial report.

We performed the procedures to assess whether in all material respects the financial report presents fairly, in accordance with the Corporations Act 2001, Australian Accounting Standards and the Singapore Exchange SGX Mainboard Rule 1207(5), a true and fair view which is consistent with our understanding of the Group's and the Company's financial position and of the Group's performance.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

KPMG

Independence

In conducting our audit, we have complied with the independence requirements of the *Corporations Act 2001*.

Auditor's opinion

In our opinion:

(a) the financial report of the Group is in accordance with the *Corporations Act 2001*, including:

  (i) giving a true and fair view of the Group's financial position as at 30 June 2015 and of its performance for the year ended on that date; and

  (ii) complying with Australian Accounting Standards and the Corporations Regulations 2001.

(b) the financial report also complies with International Financial Reporting Standards as disclosed in note 1(a).

(c) the statement of financial position of the Company gives a true and fair view of the Company's financial position as at 30 June 2015, complying with the recognition, measurement and classification requirements of Australian Accounting Standards and International Financial Reporting Standards.

Emphasis of matter: Material uncertainty regarding continuation as a going concern

Without modifying our opinion, we draw attention to Note 1(a) of the financial report which indicates that for the year ended 30 June 2015, the Group incurred a loss of $292,893,000 and as of that date, the Group had a net current liability position of $155,953,000, and that the Group is dependent on the raising of additional funds to continue as a going concern.

These conditions, along with other matters set out in note 1(a) indicate the existence of a material uncertainty which may cast significant doubt on the Group's ability to continue as a going concern and therefore its ability to realise its assets (particularly exploration and evaluation assets and other intangibles) and discharge its liabilities in the normal course of business and at the amounts recognised in the financial statements.

KPMG

KPMG

Matthew McDonnell
Partner

Brisbane, Australia
25 September 2015

SHAREHOLDER INFORMATION

The Shareholder information set out below was applicable as at 4 September 2015.

Total ordinary shares on issue: 615,966,776

Analysis of numbers of equity security holders by size of holding:

Distribution of equity security holders	No. of Shareholders
1 – 99	346
100 - 1000	3,119
1,001 - 10,000	4,577
10,001 – 1,000,000	1,613
1,000,001 and over	19
Total number of equity security holders	9,674

Twenty largest quoted equity security holders

The names of the twenty largest holders of quoted equity securities are listed below:

	Ordinary shares	
Name	Number held	Percentage of issued shares
1. DBS Nominees (Private) Limited	224,321,196	36.42
2. Genting Strategic Investments (Singapore) Pte Ltd	109,704,000	17.81
3. Raffles Nominees (Pte) Limited	42,072,966	6.83
4. Citibank Nominees Singapore Pte Ltd	32,234,369	5.23
5. RHB Securities Singapore Pte. Ltd	25,028,000	4.06
6. Phillip Securities Pte Ltd	21,129,229	3.43
7. ABN Amro Clearing Bank N.V	16,106,780	2.61
8. HSBC (Singapore) Nominees Pte Ltd	10,225,843	1.66
9. OCBC Securities Private Limited	7,969,679	1.29
10. BNP Paribas Securities Services Singapore Branch	5,637,862	0.92
11. DBS Vickers Securities (Singapore) Pte Ltd	5,147,896	0.84
12. Tay Boon Huat	4,846,900	0.79
13. DBSN Services Pte. Ltd.	2,781,573	0.45
14. Maybank Kim Eng Securities Pte. Ltd.	2,442,711	0.40
15. DB Nominees (Singapore) Pte Ltd	2,382,483	0.39
16. UOB Kay Hian Private Limited	1,857,935	0.30
17. Bank of Singapore Nominees Pte. Ltd	1,701,200	0.28
18. Lim Meng Seng	1,600,000	0.26
19. Merrill Lynch (Singapore) Pte Ltd	1,089,413	0.18
20. Sunfield Pte Ltd	1,000,000	0.16
TOTAL	519,280,035	84.30

Substantial equity security holders

The number of ordinary shares held by substantial shareholders and their associates as at 4 September 2015 are set out below:

	HOLDINGS REGISTERD IN NAME OF SUBSTANTIAL SHAREHOLDERS OR NOMINESS		HOLDINGS IN WHICH SUBSTANTIAL SHAREHOLDERS ARE DEEMED TO HAVE AN INTEREST IN	
Name	No. of Shares	%	No. of Shares	%
Genting Strategic Investments (Singapore) Pte Ltd	109,704,000	17.81	-	-
Genting Berhad[1(a)]	-	-	109,704,000	17.81
Parkview Management Sdn Bhd as trustee of Discretionary Trust[1(b)]	-	-	109,704,000	17.81
Kien Huat International Limited[1(c)]	-	-	109,704,000	17.81
Kien Huat Sdn Berhad[1(d)]	-	-	109,704,000	17.81
Tan Sri Lim Kok Thay[1(e)]	-	-	109,704,000	17.81
Lim Keong Hui[1(f)]	-	-	109,704,000	17.81
Credit Suisse Securities (Europe) Limited	56,221,774	9.13	-	-
Credit Suisse Investments (UK)[2(a)]	-	-	56,221,774	9.13
Credit Suisse Securities (Europe) Limited	62,324,365	10.12	-	-
Credit Suisse AG[3]	-	-	62,324,365	10.12
Credit Suisse Group AG[3(a)]	-	-	62,324,365	10.12
Newtron Pty Ltd (acting in its capacity as trustee of the Peter Bond Family Trust) and its affiliates (including ISNY Pty Ltd)	202,621,028	32.89	-	-

Notes

1. Genting Berhad, Parkview Management Sdn Bhd as trustee of Discretionary Trust, Kien Huat International Limited, Kien Huat Realty Sdn Berhad, Tan Sri Lim Kok Thay, Lim Keong Hui are deemed under Section 4 of the Securities and Futures Act, Chapter 289 of Singapore ("SFA") to have an interest in the Shares held by Genting Strategic Investments (Singapore) Pte Ltd as:

    (a) Genting Berhad owns 100% of the issued share capital of Genting Strategic Investments (Singapore) Pte Ltd. Accordingly, Genting Berhad is deemed to be interested in the Linc Energy Ltd shares held by Genting Strategic Investments (Singapore) Pte Ltd.

    (b) Parkview Management Sdn Bhd as Trustee of the Discretionary Trust owns 100% of the voting capital of Kien Huat International Limited which in turns owns 100% of the voting capital of Kien Huat Realty Sdn Berhad.

As such, Parkview Management Sdn Bhd as Trustee of the Discretionary Trust is deemed interested in the Linc Energy Ltd shares held by Genting Strategic Investments (Singapore) Pte Ltd, a wholly-owned subsidiary of Genting Berhad in which Kien Huat Realty Sdn Berhad controls more than 20% of the voting share capital.

(c) Kien Huat International Limited owns 100% of the voting capital of Kien Huat Realty Sdn Berhad.

As such, Kien Huat International Limited is deemed interested in the Linc Energy Ltd shares held by Genting Strategic Investments (Singapore) Pte Ltd, a wholly-owned subsidiary of Genting Berhad in which Kien Huat Realty Sdn Berhad controls more than 20% of the voting share capital.

(d) Kien Huat Realty Sdn Berhad is deemed interested in the Linc Energy Ltd shares held by Genting Strategic Investments (Singapore) Pte Ltd, a wholly-owned subsidiary of Genting Berhad in which Kien Huat Realty Sdn Berhad controls more than 20% of the voting share capital.

(e) Lim Kok Thay is deemed interested in Linc Energy Ltd shares, in which, Parkview Management Sdn Bhd as trustee of the Discretionary Trust is deemed interested in, on account of him being a beneficiary of the Discretionary Trust.

Parkview Management Sdn Bhd as Trustee of the Discretionary Trust owns 100% of the voting capital of Kien Huat International Limited which in turns owns 100% of the voting capital of Kien Huat Realty Sdn Berhad.

As such, Parkview Management Sdn Bhd as Trustee of the Discretionary Trust is deemed interested in the Linc Energy Ltd shares held by Genting Strategic Investments (Singapore) Pte Ltd, a wholly-owned subsidiary of Genting Berhad in which Kien Huat Realty Sdn Berhad controls more than 20% of the voting share capital.

(f) Lim Keong Hui is deemed interested in Linc Energy Ltd shares, in which, Parkview Management Sdn Bhd as trustee of the Discretionary Trust is deemed interested in, on account of him being a beneficiary of the Discretionary Trust.

Parkview Management Sdn Bhd as Trustee of the Discretionary Trust owns 100% of the voting capital of Kien Huat International Limited which in turns owns 100% of the voting capital of Kien Huat Realty Sdn Berhad.

As such, Parkview Management Sdn Bhd as Trustee of the Discretionary Trust is deemed interested in the Linc Energy Ltd shares held by Genting Strategic Investments (Singapore) Pte Ltd, a wholly-owned subsidiary of Genting Berhad in which Kien Huat Realty Sdn Berhad controls more than 20% of the voting share capital.

2. Credit Suisse Investments (UK) and Credit Suisse Investment Holdings (UK) are deemed under Section 4 of the Securities and Futures Act, Chapter 289 of SFA to have an interest in the Shares held by Credit Suisse Securities (Europe) Limited as:

(a) Credit Suisse AG is a wholly owned subsidiary of Credit Suisse Group AG.

3. Credit Suisse AG and Credit Suisse Group AG are deemed under Section 4 pf the Securities and Futures Act, Chapter 289 of SFA to have an interest in the shares held by Credit Suisse Securities (Europe) Limited as:

(a) Credit Suisse Investment Holdings (UK) is a subsidiary of Credit Suisse Investments (UK).

(b) Credit Suisse Securities (Europe) Limited is a subsidiary of Credit Suisse Investments Holdings (UK).

Voting rights

The voting rights attaching to each class of equity securities are set out below:

(a) Ordinary shares

On a show of hands every member present at a meeting in person or by proxy shall have one vote and upon a poll each share shall have one vote

Public Shareholders

As at 4 September 2015, 29.65% of the issued shares of the Company is held by the public and therefore the Company complies with SGX Mainboard Listing Rule 723 of the Listing Manual of the Singapore Exchange Securities Trading Limited,

Treasury Shares

As at 4 September 2015, the Company does not hold any treasury shares.

APPLICATION FOR WAIVER TO DISCLOSE QUALIFIED PERSON'S REPORTS (QPRs) IN ANNUAL REPORT

The Company advises that the Singapore Exchange Limited (SGX) has granted the Company's application for a waiver from the requirement under SGX Mainboard Listing Rule 1207(21) (a) of the Listing Manual to include QPR's in its annual report for the financial year ended 30 June 2015.

The Company sought a waiver for the following reasons:

- A material amount of information required to be disclosed in the QPRs is of a confidential and sensitive nature (as prescribed by Practice Note 6.3 of the listing Manual, such as paragraphs 5(f), 5(g), 5(h) and 5(q)). In particular, technical information with regards to the Company's mineral and petroleum leases is proprietary, and commercially sensitive in nature, providing a competitive advantage to the Company in its respective jurisdictions. This information would not be disclosed to any third party in the ordinary course of the Company's business unless such third party is bound to a non-disclosure agreement contemplating a potential corporate transaction. Accordingly, this information should not be made available to competitors or third parties.
- The QPRs contain extensive, lengthy and complex technical information which if published in the Annual Report would be of significant detriment of the Company's competitive ability, whilst at the same time of minimal significance or value to the Shareholder. The extent of disclosure would likely exceed the size of the annual report and place an undue emphasis on the QPR's. In addition, the Company disclosed all QPR's in its initial public offering on SGX-ST and listing on 18 December 2013. The technical reports provided by the Company in the offering were detailed and extensive, numbering in excess of 1,000 pages.
- The costs of including the QPRs in the Annual Report with the added logistics, time and resources (including printing and postage costs) required would result in an unnecessary use of resources and in turn cause an excessive burden on the Company.
- Subsequent to the end of each financial year, the Company seeks QPRs for each of its fields where exploration has occurred or where a material change in the reserve is knows (Updated QPRs). The Company sought a waiver to prominently place an electronic copy of each Updated QPR on its website. For those fields where no exploration has occurred and thus no material change in reserves is knows, the Company has an electronic copy of the latest QPRs, regardless of the date, displayed on our website.

In addition, the Company advises that as part of ongoing development of the Umiat and SAPEX projects, technical analysis and modelling of both assets is still being undertaken and this work needs to be completed prior to the QPRs being prepared and released. The Company will publish the revised QPRs for these assets by 31 December 2015.

The Company wishes to advise Shareholders that they can inspect a copy of the QPR's at the Company's registered office premises during office hours, upon giving notification of their intent to do so. However, Shareholders will not be allowed to make any copies of the QPR's, and the QPR's will remain on the Company's registered office premises. The Company will keep a record of the Shareholders who have viewed the QPR's.

Executive Summaries of the QPRs for the Gulf Coast and Wyoming are attached.

QUALIFIED PERSON'S REPORT
ON AN
AUDIT OF CERTAIN
OIL AND GAS INTERESTS
PREPARED BY
LINC GULF COAST PETROLEUM, INC.
LOCATED IN
LOUISIANA AND TEXAS
AS OF
JUNE 30, 2015

PREPARED FOR
LINC GULF COAST PETROLEUM, INC.

Haas Petroleum Engineering Services, Inc.
F-0002950

Rodger L. Walker, P.E.

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Table No.

EXECUTIVE SUMMARY

As authorized by Mr. Dwayne G. Jammal, Engineering Manager of Linc Gulf Coast Petroleum, Inc. (hereinafter referred to as "Linc") Haas Petroleum Engineering Services, Inc. (hereinafter referred to as "HPESI") has audited a reserve report and provided database prepared by Linc dated July 30, 2015. The properties evaluated in this report are located in Louisiana and Texas. This estimate of unrisked Reserves and Resources was completed on or about the above date of this letter. This report was prepared as part of the Qualified Person's Report on Linc to be submitted to the Singapore Stock Exchange ("SGX") by Linc Energy, Ltd. and conforms to the guidelines specified by the Society of Petroleum Engineers ("SPE"), American Association of Petroleum Geologists ("AAPG"), World Petroleum Council ("WPC"), the Society of Petroleum Evaluation Engineers ("SPEE"), and the 2007 Petroleum Resource Management System ("PRMS"). For the purpose of this audit, HPESI has examined approximately 80 percent of the Reserves' NPV listed in Table 1 and 80 percent of the Resources' volumes listed in Table 2. It is our understanding that this audit contains 100 percent of Linc's Proved Reserves and Prospective Resources. It is HPESI's opinion that the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for this purpose.

PROVED RESERVES ESTIMATES

Production data was generally available through 6/30/2015. As of June 30, 2015, Linc's net Reserves, future net income ("FNI"), and net present worth discounted at 10 percent per annum ("NPV") have been estimated to be as follows:

TABLE 1

	Net Reserves - As of 6/30/2015			
Reserve Class/Cat	**Oil & Condensate (bbl)**	**Natural Gas (Mcf)**	**FNI ($)**	**NPV Disc. @ 10% ($)**
Proved Producing	2,019,680	264,160	82,033,680	64,381,870
Proved Shut-In	68,720	640,710	(5,523,660)	(2,712,350)
Proved Non-Producing	1,838,000	1,196,790	86,905,080	51,954,270
Proved Undeveloped	3,811,830	1,217,780	162,009,060	80,281,540
Total Proved	**7,738,230**	**3,319,440**	**325,424,160**	**193,905,330**

* Totals in Table 1 may not exactly match values in the attached cash flow summaries and tabular summaries due to computer rounding.

It is the opinion of HPESI that the Reserves, FNI and NPV estimates listed in Table 1 are, in aggregate, reasonable and meet audit standards for the top 80% of the value in the portfolio. FNI is after deducting estimated operating and future development costs, severance and ad valorem taxes, but before Federal income taxes. Total net Proved Reserves are defined as those natural gas and hydrocarbon liquid Reserves to Linc's interests after deducting all royalties, overriding royalties, and reversionary interests owned by outside parties that become effective upon payout of specified monetary balances. All Reserves estimates have been prepared using standard engineering practices generally accepted by the petroleum industry and conform to guidelines developed by SPE, AAPG, WPC, SPEE, and PRMS. All hydrocarbon liquid Reserves are expressed in United States barrels ("bbl") of 42 gallons. Natural gas

Reserves are expressed in thousand standard cubic feet ("Mcf") at the contractual pressure and temperature bases and include shrinkage adjustment related to field and plant losses.

RESERVES ESTIMATE METHODOLOGY

It is the opinion of HPESI that the Reserves estimates contained in this report have been prepared using standard engineering practices generally accepted by the petroleum industry. Decline curve analysis was used to estimate the remaining Reserves of pressure depletion reservoirs with enough historical production data to establish decline trends. Reservoirs under non-pressure depletion drive mechanisms and non-producing Reserves were estimated by volumetric analysis, research of analogous reservoirs, or a combination of both. The appropriate methodology was used, as deemed necessary, to estimate Reserves in conformance with the PRMS guidelines. The maximum remaining Reserves life assigned to wells included in this report is 40 years. This report does not include any gas sales imbalances.

RESERVES CLASSIFICATION

The Reserves estimates included in this report conform to the guidelines specified by the SPE, AAPG, WPC, SPEE, and PRMS. For more information regarding Reserves classification definitions see Appendix A. A complete discussion of the Reserves classification definitions can be found on the SPE website (www.spe.org).

COMMODITY PRICES

The cash flow projections in this report utilize the unweighted 12 month arithmetic average of the first-day-of month benchmark prices for July 2014 through June 2015. The benchmark price for natural gas is taken to be the price received at Henry Hub and the benchmark price for hydrocarbon liquids is taken to be the price received for WTI Cushing, Oklahoma Spot Price.

The unweighted arithmetic average cash market price for natural gas delivered at Henry Hub during this time period is $3.39 per MMBTU. The Henry Hub price was held constant throughout the life of the wells and is adjusted for BTU content, basis differentials, and marketing costs, resulting in a weighted average net price of $3.49 per Mcf.

The unweighted arithmetic average cash market price for WTI Cushing, Oklahoma Spot Price during this time period is $71.68 per bbl. For crude oil, the WTI crude oil price was held constant throughout the life of the wells and is adjusted for crude quality, marketing fees, BS&W, transportation costs, purchaser bonuses and basis differentials, resulting in a weighted average net price of $68.98 per bbl.

Revenue accounting data for the period of 7/1/2014 to 6/30/2015 was used in this evaluation. The pricing adjustments were provided by Linc and reviewed for 80 percent of the NPV. The Natural Gas Liquids ("NGL") plant at Atkinson Island / Cedar Point fields has been removed. HPESI verified the reasonableness of the pricing models using accounting data provided by Linc.

OPERATING EXPENSES & CAPITAL COSTS

In most cases, the lease operating costs used in this evaluation represent the average of recent historical monthly operating costs. In cases where historical costs were not available or deemed to be unreliable, operating costs were estimated based on knowledge of analogous wells producing under similar conditions. The lease operating expenses in this report represent field level operating costs and do not include COPAS charges.

Linc has recently implemented an operating cost reduction plan, primarily in employee and contract gauging and chemical costs that will lower overall costs by approximately 15%. HPESI verified the reasonableness of Linc's operating expense models using accounting data furnished by Linc.

Where available, capital costs were estimated using recent historical information reported for analogous expenditures. Where recent historical information was not available, Authority for Expenditure ("AFE") documents were used to estimate capital costs. AFE documents provided by the operator have been checked for reasonableness. Abandonment costs have been included for each field.

Operating expenses and capital costs were not escalated in this evaluation.

PROSPECTIVE RESOURCES ESTIMATES

As of June 30, 2015, Linc's Prospective Resources have been estimated to be as follows:

TABLE 2

Prospective Resources - As of 6/30/2015

	Gross		Net	
	Oil	**Gas**	**Oil**	**Gas**
Reserve Class/Cat	**(bbl)**	**(Mcf)**	**(bbl)**	**(Mcf)**
Prospective Resources	3,257,830	4,706,030	2,492,820	3,482,460

All Resources estimates have been prepared using standard engineering practices generally accepted by the petroleum industry and conform to guidelines developed by SPE, AAPG, WPC, SPEE, and PRMS. All hydrocarbon liquid Resources are expressed in United States barrels ("bbl") of 42 gallons. Natural gas Resources are expressed in thousand standard cubic feet ("Mcf") at the contractual pressure and temperature bases.

RESOURCES ESTIMATE METHODOLOGY

It is the opinion of HPESI that the Resources estimates contained in this report have been prepared using standard engineering practices generally accepted by the petroleum industry. Non-producing Resources were estimated using deterministic methodology in conformance with the PRMS guidelines.

RESOURCES CLASSIFICATION

The Resources estimates included in this report conform to the guidelines specified by the SPE, AAPG, WPC, SPEE, and PRMS. For more information regarding Resources classification definitions see Appendix A. A complete discussion of the Resources classification definitions can be found on the SPE website (www.spe.org).

Summary of Oil and Gas Reserves and Resources

Name of Asset/Country: Linc Gulf Coast Petroleum, Inc./United States of America

Category	Gross Attributable to Licence (MMbbl / Bcf)	Net Attributable to Issuer		Remarks
		(MMbbl / Bcf)	Change from previous update (%)	
Reserves				
Oil Reserves				
1P	10.2	7.8	-36.4%	
2P	10.2	7.8	-36.6%	
3P	10.2	7.8	-36.6%	
Natural Gas Reserves				
1P	3.7	2.5	-21.1%	
2P	3.7	2.5	-21.1%	
3P	3.7	2.5	-21.1%	

Prospective Resource				
Oil				
Low				
Best	3.3	2.5	N/A	
High				
Natural Gas				
Low				
Best	4.7	3.5	N/A	
High				

1P: Proved
2P: Proved + Probable
3P: Proved + Probable + Possible

MMbbl: Millions of barrels
Bcf: Billions of cubic feet

Name of Qualified Person: Rodger L. Walker Rodger L Walker
Date:______July 28, 2015_____
Professional Society Affiliation / Membership:__State of Texas Professional Engineer_

Property Description
GULF COAST OIL AND GAS LEASES

No.	Lease Name	Lessor	County	State	Gross Acres	Expiry Date [1]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
1	Welch Foundation	The Robert A. Welch Foundation	Brazoria	TX	2500	upon permanent cessation of production	oil and gas	65.00% - 100.00%	47.75000% - 71.50000%
2	State Tract 216	State of Texas Lease No. M-71950	Calhoun	TX	640	upon permanent cessation of production	oil and gas	100.00%	78.37500%
3	State Tract 224	State of Texas Lease No. M-116766	Calhoun	TX	40	July 1, 2019	oil and gas	100.00%	80.00000%
4	E.W. Barber "D" (Samson) Lease	J. R. Barber, et al	Chambers	TX	25	upon permanent cessation of production	oil and gas	100.00%	74.54770%
5	A.E. Barber Lease	Arthur E. Barber, et ux	Chambers	TX	73	upon permanent cessation of production	oil and gas	100.00%	79.00000%
6	L.E. Fitzgerald Unit	Mary O. Scott, et vir	Chambers	TX	47.77	upon permanent cessation of production	oil and gas	100.00%	78.63000%
		Sarah E. Morgan, et vir et al	Chambers	TX					
		Alma A. Eberspacher, et al	Chambers	TX					
		Anna Davis and A. C. Davis	Chambers	TX					
		F.M. Fitzgerald, et al	Chambers	TX					
		T.C. Fitzgerald and Wife	Chambers	TX					
7	Kirby "B" Lease	Kirby Petroleum Company, et al	Chambers	TX	107.864	upon permanent cessation of production	oil and gas	100.00%	79.07137%
8	Kirby "C" Lease	John Shearer	Chambers	TX	15	upon permanent cessation of production	oil and gas	100.00%	79.00000%
		Kirby Petroleum Company, et al	Chambers	TX					
9	Kirby Petroleum Company (Samson) Lease	Kirby Petroleum Company	Chambers	TX	49.5	upon permanent cessation of production	oil and gas	100.00%	74.00000%
10	Espey Lease	Robert H. Espey II, Lin G. Espey and William P. Espey and Union Seaboard Corporation	Chambers	TX	60.26	upon permanent cessation of production	oil and gas	100.00%	74.00000%
11	Gulf Fee Fisher (mineral ownership - Linc fee to 6000')	N/A - fee	Chambers	TX	23.5	upon permanent cessation of production	oil and gas	100.00%	84.00000%
12	J. Wilburn	Jerry Wilburn, et ux., et al	Chambers	TX	65	upon permanent cessation of production	oil and gas	100.00%	83.50000%
13	J. F. Wilburn "B"	Jerry Wilburn, et al	Chambers	TX	50	upon permanent cessation of production	oil and gas	100.00%	77.66663%
		Mrs. Amanda McKinney, Guardian	Chambers	TX					
14	Wilburn "C" #9 and #10 / Wilburn "D" / Wilburn "E"	J.F. Wilburn, et al	Chambers	TX	93.95	upon permanent cessation of production	oil and gas	100.00%	67.00000% - 71.62500%
15	Wilburn, J. "A"	Lillian Wilburn, et al	Chambers	TX	52.5	upon permanent cessation of production	oil and gas	100.00%	74.27064%
		W. Howard Lee, et al	Chambers	TX					
16	Higgins	Annie Higgins, et al	Chambers	TX	16.57	upon permanent cessation of production	oil and gas	100.00%	81.50000%
17	Higgins -B-	Annie Higgins and Pattillo Higgins	Chambers	TX	7.05	upon permanent cessation of production	oil and gas	100.00%	75.86110%
18	Chambers County Agricultural Company	Chambers County Agricultural Company	Chambers	TX	205.1	upon permanent cessation of production	oil and gas	100.00%	86.50130%
19	Fitzgerald, J.M. ("A")	Frank M. Fitzgerald, et al	Chambers	TX	50.44	upon permanent cessation of production	oil and gas	94.50%	65.96000%
20	Lot 3A Strip Leases	David Glenn Barber, et ux	Chambers	TX	4.485	upon permanent cessation of production	oil and gas	87.50% - 100.00%	65.18750% - 74.50000%
		Big Sky Mineral Trust	Chambers	TX					
		Raymond E. Brizendine	Chambers	TX					
		James M. Brown II	Chambers	TX					
		Bevis Jerome Minter	Chambers	TX					
		William Michael Minter, et ux	Chambers	TX					
		Cheri Barber Orchin	Chambers	TX					
		S & C Properties	Chambers	TX					
		Southwest Petroleum Company L.P.	Chambers	TX					
		Frank D. Schubert	Chambers	TX					
		Nancy Barber Welwood	Chambers	TX					
21	Lot 5A Strip Leases	Dolores P. Direzza	Chambers	TX	4.427	upon permanent cessation of production	oil and gas	93.75% - 100.00%	71.56250% - 76.33333%
		Edward C. Kerley	Chambers	TX		upon permanent cessation of production			
		Patty Lou Kyffin	Chambers	TX		upon permanent cessation of production			
		Eddie Clyde Bell	Chambers	TX		upon permanent cessation of production			
		James Lee McLean, Trustee	Chambers	TX		upon permanent cessation of production			
		Pamela S. Pilkington	Chambers	TX		upon permanent cessation of production			
		Stephen M. Wright	Chambers	TX		upon permanent cessation of production			
		Thomas F. Wright	Chambers	TX		upon permanent cessation of production			
22	Conoco Lease	ConocoPhillips Company	Chambers	TX	98.03	upon permanent cessation of production	oil and gas	100.00%	74.00000%
23	UPRC Lease (3.3 ac.)	Union Pacific Railroad Company	Chambers	TX	3.3	upon permanent cessation of production	oil and gas	100.00%	74.00000%
24	UPRC Lease (21.93 ac.)	Union Pacific Railroad Company	Chambers	TX	21.93	November 1, 2015	oil and gas	100.00%	74.00000%
25	UPRC Lease (2.323 ac.)	Union Pacific Railroad Company	Chambers	TX	2.323	February 11, 2016	oil and gas	100.00%	74.00000%
26	Nelson Lease	NEQ Investments, LTD	Chambers	TX	13.52	January 18, 2016	oil and gas	100.00%	76.50000%
27	M Winfree Heirs Lease	M Winfree Heirs, LLC	Chambers	TX	58.88	July 23, 2015	oil and gas	100.00%	74.00000%
28	Brian Collins	Brian Collins	Chambers	TX	84.95	May 3, 2015	oil and gas	100.00%	82.33333%

Property Description
GULF COAST OIL AND GAS LEASES

No.	Lease Name	Lessor	County	State	Gross Acres	Expiry Date (1)	Use of Property	Working Interest (%)	Net Revenue Interest (%)
29	Farish Fund Leases	Texas Gulf Bank, N.A. Trustee of The Joan H. Blaffer Trust A	Chambers	TX	7.28	June 17, 2015	oil and gas	100.00%	74.00000%
		Sarah B Hrdy, Trustee of the Sarah B. Hardy Trust B	Chambers	TX		May 16, 2015			74.00000%
		Texas Gulf Bank, N.A. Trustee of the Joan B. Johnson Trust B	Chambers	TX		July 17, 2015			74.00000%
		Camilla Blaffer, Trustee of the Camilla Blaffer Royall Mallard Trust B	Chambers	TX		June 17, 2015			74.00000%
30	Maranatha Temple Lease	Judith A Honsinger	Chambers	TX	26.91	July 24, 2016	oil and gas	100.00%	77.50000%
		Brian Honsinger	Chambers	TX		July 30, 2016			
		Virgil Sanders & Janise Karen Sanders	Chambers	TX		July 24, 2016			
		Nancy Franklin Wyckoff	Chambers	TX		July 24, 2016			
		Scott Franklin Jordan	Chambers	TX		August 20, 2016			
		Amanda Jane Jordan	Chambers	TX		December 3, 2016			
31	T.S. Fitzgerald Heirs	Mary Beth Dyer	Chambers	TX	10	June 20, 2016	oil and gas	100.00%	75.00000%
		Deborah F Nelson	Chambers	TX		June 20, 2016			
		Temple Benson Dunaway	Chambers	TX		June 20, 2016			
		Michael S Lansford	Chambers	TX		June 20, 2016			
		Carl Wesley Benson	Chambers	TX		June 20, 2016			
		T. Steve Fitzgerald	Chambers	TX		June 21, 2016			
		Bennie L Lansford	Chambers	TX		June 21, 2016			
		Tyler S. Fitzgerald	Chambers	TX		June 21, 2016			
		Carlene Fitzgerald Egloff	Chambers	TX		June 22, 2016			
32	State Tract 118	State of Texas Lease #19819	Chambers	TX	640	upon permanent cessation of production	oil and gas	75.00% - 100.00%	56.25000% - 84.00000%
33	State Tract 94	State of Texas Lease #M-116767	Chambers	TX	320	July 1, 2019	oil and gas	100.00%	80.00000%
34	State Tract 95	State of Texas Lease #M-116768	Chambers	TX	320	July 1, 2019	oil and gas	100.00%	80.00000%
35	State Tract 125	State of Texas Lease #M-115873	Chambers	TX	320	October 1, 2018	oil and gas	100.00%	80.00000%
36	State Tract 126	State of Texas Lease #74324	Chambers	TX	360	upon permanent cessation of production	oil and gas	100.00%	77.20000%
37	State Tract 126A	State of Texas Lease #M-108139	Chambers	TX	280	upon permanent cessation of production	oil and gas	100.00%	77.20000%
38	State Tract 127	State of Texas Lease #M-115903	Chambers	TX	320	October 1, 2018	oil and gas	100.00%	80.00000%
39	State Tract 72	State of Texas Lease #M-115872	Chambers	TX	40	October 1, 2018	oil and gas	100.00%	80.00000%
40	State Tract 88	State of Texas Lease #M-116169	Chambers	TX	40	January 7, 2019	oil and gas	100.00%	80.00000%
41	Moody 1	The Estate Of Shearn Moody, Jr., deceased	Galveston	TX	40	upon permanent cessation of production	oil and gas	100.00%	72.95774%
42	Moody 2	Robert L. Moody	Galveston	TX	180	upon permanent cessation of production	oil and gas	100.00%	72.95774%
43	Moody 3	Robert L. Moody	Galveston	TX	10	upon permanent cessation of production	oil and gas	100.00%	72.95774%
44	Jakovich Lease	Carey Stehling Independent Executor of the Estate of Edward Jakovich, Deceased	Galveston	TX	40	upon permanent cessation of production	oil and gas	100.00%	72.95774%
		Donna Cameron Goode	Galveston	TX					
		Linda Jakovich Meyer Independent Executrix of the Estate of Andrew Jakovich, Deceased	Galveston	TX					
		DJS Land Company, Ltd	Galveston	TX					
		Carol Ann Burns	Galveston	TX					
45	Overton Cade Heirs Leases	Marie Howell Cade, et al	Galveston	TX	10	upon permanent cessation of production	oil and gas	100.00%	71.77600% - 74.00000%
		Beverly Hodges Davis	Galveston	TX					
		Roy Hamilton Davis, Individually & as Agent and Attorney in Fact	Galveston	TX					
		Frances Henshaw Gill	Galveston	TX					
		Ashbel Burnham Henshaw	Galveston	TX					
		Linda Jean Lee Henshaw, et al	Galveston	TX					
		Thomas R. Howell Jr., Individually and as Successor Trustee	Galveston	TX					
		Mary Henshaw Jernigan	Galveston	TX					
		James & Tolley Odom Family, LLC, by Martha Tolley Davis Odom, Manager	Galveston	TX					
		Barbara Henshaw Roberts	Galveston	TX					
		Linda Henshaw Weeks	Galveston	TX					
46	Henshaw-Cade Leases	Marie Howell Cade, et al	Galveston	TX	10	upon permanent cessation of production	oil and gas	100.00%	71.77600% - 74.00000%
		Beverly Hodges Davis	Galveston	TX					
		Roy Hamilton Davis, Individually and as Agent and Attorney in Fact	Galveston	TX					
		Frances Henshaw Gill, by Gregory D. Gill, Agent and Attorney in Fact	Galveston	TX					
		Ashbel Burnham Henshaw	Galveston	TX					
		Linda Jean Lee Henshaw, et al	Galveston	TX					
		Thomas R. Howell, Jr., Individually and as Successor Trustee	Galveston	TX					
		Mary Henshaw Jernigan	Galveston	TX					
		James & Tolley Odom Family, LLC, by Martha Tolley Davis Odom, Manager	Galveston	TX					
		Barbara Henshaw Roberts	Galveston	TX					
		Linda Henshaw Weeks	Galveston	TX					

Property Description
GULF COAST OIL AND GAS LEASES

No.	Lease Name	Lessor	County	State	Gross Acres	Expiry Date [1]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
47	Kate Taylor Heirs Leases	D. Caffery McCay, et al	Galveston	TX	10	upon permanent cessation of production	oil and gas	100.00%	71.77600% - 74.00000%
		Maryann Ellis Bohr	Galveston	TX					
		Blair Lea Ellis	Galveston	TX					
		Lloyd Addison Ellis, III	Galveston	TX					
		Marion Caffery Campbell, Trustee	Galveston	TX					
48	Barker /Cade Leases	Charles H. Barker	Galveston	TX	20	upon permanent cessation of production	oil and gas	100.00%	71.77600% - 74.00000%
		Robert C. Barker	Galveston	TX					
		T. C. Craighead & Company	Galveston	TX					
		Katherine C. Holt Trust	Galveston	TX					
		David T. Speer	Galveston	TX					
		Betty Speer Taylor	Galveston	TX					
		Ruth McLean Bowers	Galveston	TX					
49	Bowers/McNeill Leases	Ruth McLean Bowers	Galveston	TX	50	upon permanent cessation of production	oil and gas	100.00%	74.00000% - 80.50000%
		Barbara Gordon McNeill & Melinda Gordon Paret	Galveston	TX					
50	George E. Smith "A" Lease	George E. Smith	Galveston	TX	88.28	upon permanent cessation of production	oil and gas	100.00%	73.58332% - 73.75000%
51	George E. Smith "B" Lease	George E. Smith	Galveston	TX	96.48	upon permanent cessation of production	oil and gas	100.00%	73.84115%
52	Nellie B. League Lease	Nellie B. League, et al	Galveston	TX	24.83	upon permanent cessation of production	oil and gas	100.00%	74.00000%
53	Charlotte E. Smith Lease	Charlotte E. Smith	Galveston	TX	426.12	upon permanent cessation of production	oil and gas	100.00%	84.41667%
54	Elizabeth Kerr Cade, et al Lease	Elizabeth Ker Cade, et al	Galveston	TX	790	upon permanent cessation of production	oil and gas	100.00%	71.77600% - 74.00000%
55	BP America Lease	BP America Production Company	Galveston	TX	35.49	upon permanent cessation of production	oil and gas	100.00%	71.77600% - 74.00000%
56	Gulf Interstate Lease	The Gulf and Inter-State Railway Company of Texas	Galveston	TX	19.3	upon permanent cessation of production	oil and gas	100.00%	96.91667%
57	Harrell "C" Lease	Edwin Tabb Harrell, et al	Harris	TX	1	upon permanent cessation of production	oil and gas	100.00%	70.00000% - 74.25000%
58	Rena Berry Fee	Mary Addilea Koehl, Executor of the Estate of Rena Berry, Deceased	Harris	TX	2.5	upon permanent cessation of production	oil and gas	100.00%	74.25000%
59	Tabb "A" Lease / Tabb "B" Lease / W. Tabb "A" Lease	Edwin Harrell	Harris	TX	14.63	upon permanent cessation of production	oil and gas	100.00%	70.00000% - 72.00000%
		C. Tabb Harrell, et ux	Harris	TX					
60	Armelin, L. Fee	Louis Armelin, et ux	Liberty	TX	98	fee	oil and gas	100.00%	91.70834%
61	Baldwin, J. C. Fee	Jacob C. Baldwin	Liberty	TX	35	fee	oil and gas	100.00%	86.50000%
62	Failor, E. K. Fee	E. K. Failor	Liberty	TX	160	fee	oil and gas	100.00%	92.75000%
63	Hannah, D. Lease	David Hannah, et ux	Liberty	TX	5	upon permanent cessation of production	oil and gas	100.00%	82.33340%
64	Hannah, D. Fee	David Hannah	Liberty	TX	50	fee	oil and gas	100.00%	86.50000%
65	Stark	W. H. Stark	Orange	TX	986.75	upon permanent cessation of production	oil and gas	100.00%	82.33333%
66	Polk "A"	James V. Polk, et al	Orange	TX	600	upon permanent cessation of production	oil and gas	100.00%	83.20138%
67	Polk "B"	James V. Polk, et al	Orange	TX	1016	upon permanent cessation of production	oil and gas	100.00%	83.20138%
68	Kuhn	Harry J. Kuhn, et al	Orange	TX	1199.5	upon permanent cessation of production	oil and gas	100.00%	83.37500%
69	JB Watkins	Bonne Terre Exploration Company, L.L.C. & Nexus Resources, L.L.C.	Cameron	LA	2435	May 1, 2016	oil and gas	87.50% - 100.00%	61.75586% - 72.00000%
70	Constantin #2	Conveyed in Partial Assignment, Bill of Sale and Conveyance from SUCO Energy Partners, L.P. to DIASU Holdings, L.L.C., dated June 12, 2009 (1784/213).	Lafourche	LA	100	upon permanent cessation of production	oil and gas	41.41%	28.07413%

NOTES:
(1) Leases in the Gulf Coast Region typically remain in effect for the primary term of the lease and subsequently for so long thereafter as production is obtained in paying quantities.

Property Overview

1. Barbers Hill

- Operator: Linc
- WI/NRI: 100%/75%
- Acreage: 1,186 gross (1,184 net)
- 3D seismic: 43 sq. mi.

History
Barbers Hill field was discovered by Gulf Production (Chevron) and Humble Oil and Refining (Exxon) in 1916. This discovery well produced only 40 BOPD and watered-out in a few months. Finally, in 1918 the first commercial well was drilled by United Petroleum producing 70 BOPD for a period of 15 months. By 1919 the field was producing 600 BOPD. In 1930 the first well to produce from below a salt dome overhang was drilled in this field at a depth of just below 5,000 feet. Peak annual production came in 1931, when 8,085,278 barrels were recovered. Presently the field is producing over 2,000 BOPD. The cumulative field production is greater than 130,000,000 barrels of oil.

Through the years there has been a succession of owners. The field was purchased by Linc in 2011 from the previous operators, a company that between 1998 and 2004, consolidated the ownership of the field through a series of acquisitions and new leasing activity. Today Linc continues active leasing and drilling programs in the field.

Geology
Barbers Hill field is formed by a complexly faulted piercement salt dome. The crest of the dome or “top of salt” is at approximately 1,000 feet below ground level. The piercement designation allows for the suspension of state well spacing rules and has facilitated the intense development history of the field. The dome has a prominent salt overhang or canopy that extends outward from the salt core. Because of this shape and the timing of the movement of the salt, the reservoirs are steeply dipping thus exposing a significant cross section of the reservoir to the wellbore allowing for relatively high initial production rates. As a result of the steeply dipping beds and initial development using vertical wellbores, many pay zones have updip, bypassed pay still to be exploited.

The field produces from stacked Miocene and Frio aged reservoirs ranging in depth from 1,500 to 7,500 feet. The Miocene and Frio reservoirs are separated by a field-wide unconformity at the top of the Frio. In addition to the traditional salt flank reservoirs, the field also has had production from the cap rock reservoir. Linc’s current development effort is to drill updip of previously productive wells in order to test attic oil potential trapped underneath the salt overhang and near the salt core.

Seismic
Approximately 43 square RTM miles of newly reprocessed seismic data has was received on September 14, 2014 from Global Geophysical. Input from well control has better defined the sediment/salt interface which will aid in delineating existing prospects and aid in new prospect development.

Land

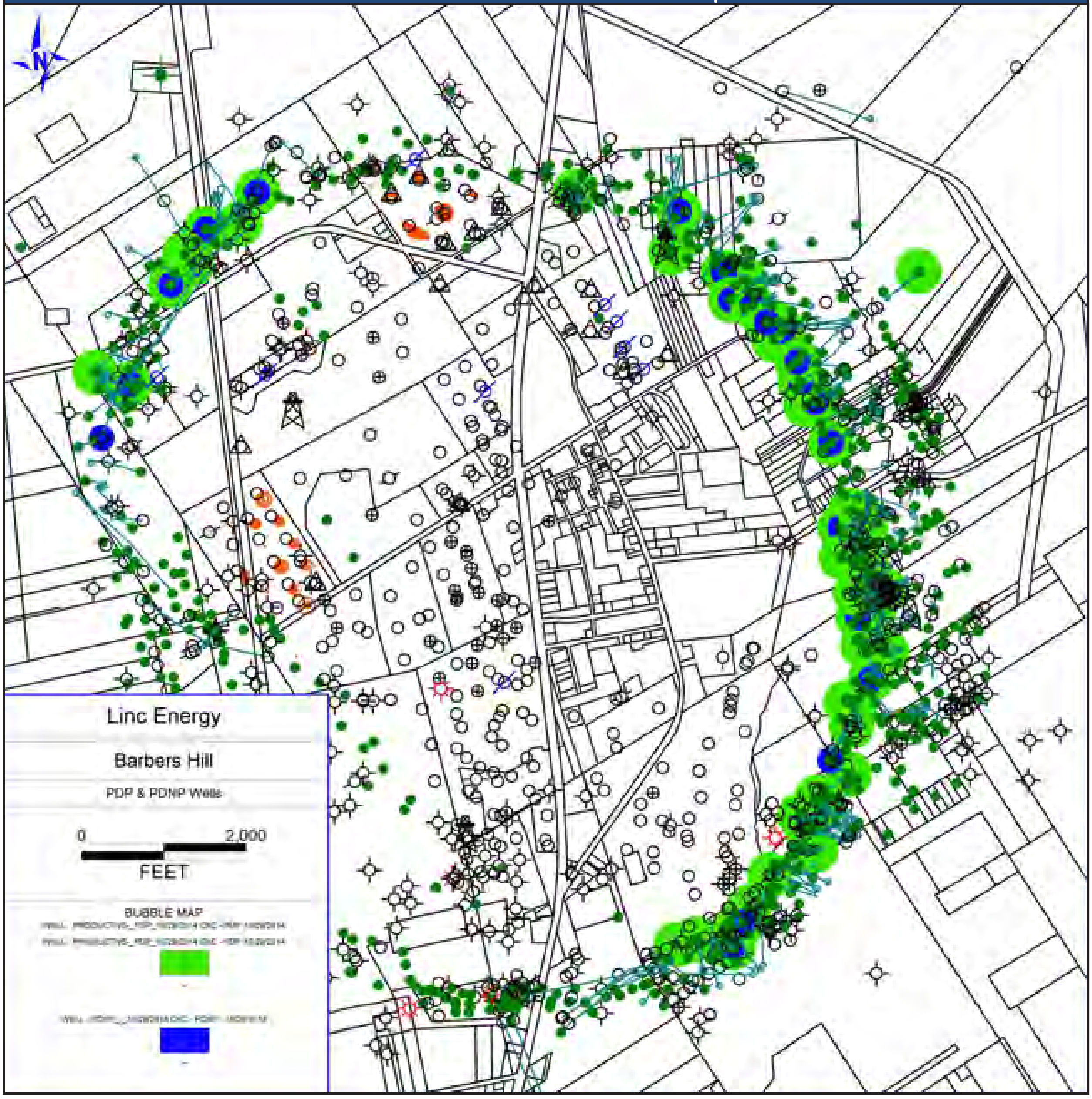
The leasehold at Barbers Hill falls within an area of high industrial activity. This creates competition for surface use with chemical, storage and pipeline companies. Most of Linc's leases are held-by-production, and some have been in effect for nearly a century. Not only do most of Linc's lease rights pre-date the industrial operations at Barbers Hill, but the State of Texas has also adopted the "accommodation" doctrine, which means that the owner of the oil and gas rights may use the surface as required to exploit the minerals with due regard to the surface owners. As a result, Linc is able to find and build locations suitable for its targets through the rights granted in its oil and gas leases.

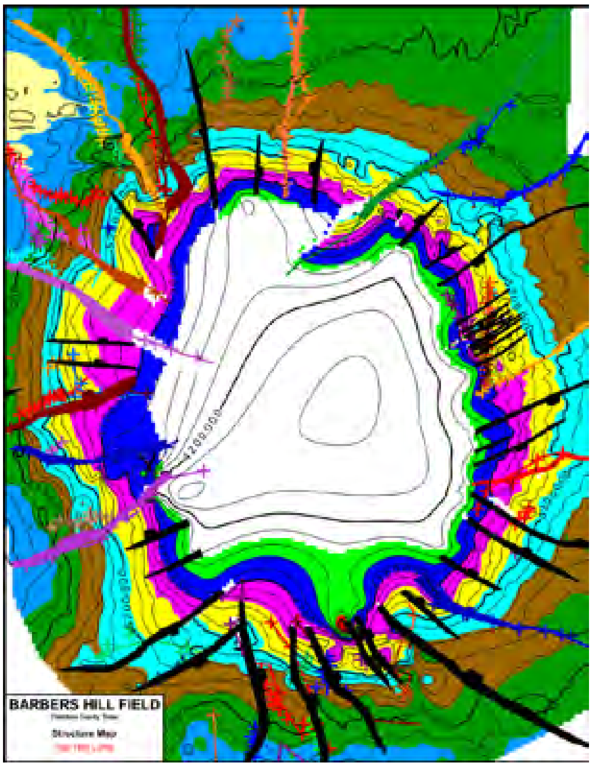
As many of Linc's wells at Barbers Hill are highly deviated, they are occasionally drilled from surface locations outside the confines of the targeted lease. In these situations, Linc acquires Surface Use Agreements and/or Surbsurface Easements from the land owner(s). Gathering lines and flow lines sometimes traverse off-lease tracts as well, so Linc has obtained several Rights-of-ways and Easements from the surface owner(s). Obligations related to these surface contracts often involve annual rental payments.

Operational Overview

Barbers Hill consists of 57 producing and 75 inactive wells. All of the wells are produced using rod pumping units driven by electric motors. Very little gas is produced and none is sold. Most wells flow to central tank batteries located throughout the field. Oil is sold at these tank batteries utilizing trucks. Saltwater is disposed of utilizing three onsite disposal wells.

Barbers Hill Structure Map



Barbers Hill Structure Map	Representative Field Development Schematic
	

2. High Island

- Operator: Linc
- WI/NRI: 100%/74%
- Acreage: 1,611 gross (1,610 net)
- 3D seismic: 18 sq. mi.

History
Exploration at High Island began in 1901 leading to the first commercial discovery in 1922, in shallow caprock pay. In 1931 overhang production was proved up at a depth of 5,077 feet. Later, in 1947, flank production was confirmed at 7,413 feet. Steady development over the ensuing years and the introduction of water injection in 1959 led to a peak production rate in 1964 of approximately 30,000 BOEPD. In the first 12 years of its life, the field produced over 9.3 MMBBLS and to date has accumulated over 140 MMBBLS. The latest phase of field development is based on directionally drilling into reservoirs that were bypassed by vertical wells. The previous operator acquired its High Island position through acquisitions from Stroud Production and Point Capital in 2007, which gave them a controlling position over the field. Linc acquired this asset in 2011.

Geology
The High Island field is a typical Gulf Coast salt dome field with production on the flanks of the salt dome separated by radial faulting. The field is a piercement salt dome structure and has approximately 14 named sand intervals and about 25 possible sand targets that have already proved productive. Oil bearing sands have proved productive from 2,000 feet to 4,700 feet. Cumulative oil production is over 140 MMBBLS. The deeper Frio section has sand in off-structure positions but has not been targeted on the flanks of the dome on Linc acreage.

The field produces from a series of stacked Miocene through Frio age reservoirs separated by a field wide unconformity located at the top of the Oligocene. A result of the steeply dipping beds and initial development using vertical wellbores is that many pay zones have up-dip, bypassed pay still to be exploited.

The structural and stratigraphic complexity in the field offers a variety of trapping mechanisms that provide numerous exploitation opportunities in the form of recompletions and new wells. The complex trapping mechanisms and the steeply dipping beds allows for some of the deeper, thin sands to have hydrocarbon columns of up to 1,000 vertical feet. Many of the earlier wells were drilled vertically and hence missed much of the steeply dipping, up-dip pay located in the field.

The four general play types within the field include: shallow (<4,800 feet) oil reservoirs trapped against salt face; upturned, steeply dipping oil reservoirs trapped under salt overhang; oil reservoirs trapped under field wide unconformity; and oil reservoirs trapped against up-thrown side of tangential fault dipping towards salt dome.

Seismic
Linc has acquired 18 square miles of a 2006 vintage seismic survey covering all of High Island Field. The survey was reprocessed in 2007 and contains 40+ attribute stacks including AVO gathers. These volumes will allow for thorough analysis of structure and rock properties, as well as significant de-risking of current leads and prospects based only on subsurface mapping and well log correlation. Historically, drilling and exploration at High Island was done without the aid of 3D seismic; this puts Linc at a significant advantage in the process of exploiting remaining reserves.

Land

Linc's leasehold at High Island Field falls within an area designated by the U. S. Army Corps of Engineers as "wetlands". The field is also designated by the Texas Railroad Commission as a Hydrogen Sulfide ("H2S") field. Both of these scenarios create unique permitting conditions that we must adhere to. Because Linc is in a wetlands area, it must obtain permits from the USACE prior to drilling (exception to this rule could be if Linc is building a pad on land that has been "pre-disturbed"). The H2S designation requires filing for additional permit(s) with the Railroad Commission, i.e. Form H-9, which must be obtained prior to W-1 drilling permit approval.

Operational Overview

High Island consists of 18 producing and 30 inactive wells. All of the wells are produced using rod pumping units driven by electric motors. Very little gas is produced and none is sold. All wells flow to central tank batteries located throughout the field. Oil is sold at these tank batteries utilizing trucks. Saltwater is disposed of utilizing two on site disposal wells.

3. Atkinson Island

- Operator: Linc
- WI/NRI: 100%/79%
- Acreage: 1,280 gross (1,280 net)
- 3D seismic: 21 sq. mi.

History

The wells drilled at Atkinson Island in the 1940-1950's, primarily by Humble Oil & Refining Co. (the precursor to Exxon), focused the drilling to the southeast of the present day producing platform. Humble's subsurface interpretation envisioned a structure further to the southeast along the large down to the northeast fault. Although many of the older wells had, by today's standards, high oil flow rates, the field was not economic at the time.

Texas Crude discovered the core of the Atkinson Island Field in 1981. Cumulative production since 1981 from the field is nearly 2 MMBBLS and 10 BCF. The discovery well, The Texas Crude # 1 ST TR 126 was drilled on the crest of the company's interpreted structure. Subsequently, the delineation wells, the #2 and #3 ST TR 126 wells were drilled. The #1 well encountered over 70 feet of pay, and combined with the other two wells, has produced over 600 MBBLS. Oil and gas exploration during the early 1980's was accomplished by the use of available pre-existing well logs and 2D seismic data. The location of the Texas Crude wells indicates their interpretation of the crest of the Frio Formation structure is located to the northwest.

The advent of 3D seismic data in the onshore and transition zone areas of the Texas Gulf Coast reinvigorated the exploration for commercial oil and gas. The 3D seismic data over Galveston Bay has defined numerous opportunities at Atkinson Island. Beginning in the mid-1990's, 3D seismic data was utilized to explore in Galveston Bay. More accurate definition of field indicates the more complex structural nature of the Atkinson Island Field. Subsequent drilling has significantly expanded the field limits to the northeast. Linc became operator after acquiring the interest in the field in 2011.

Geology

Production is from Late Oligocene Upper Frio formation sands. The Upper Frio Formation sands were deposited as a result of the deltaic marine building process of the Houston Delta within the Houston salt embayment. The upper most sands are the best reservoir quality sands within the Frio Formation. The marine flooding event over the delta provides the shale source rock for the eventual reservoir at Atkinson Island. The modern day island sits on the ancestral high portion of this portion of the entrance to Galveston Bay. The large downthrown fault, on the northeast boundary of the field, produces the three way closure for the oil accumulation at Atkinson Island Field. Salt piercement activity also effects deposition of sands within the Houston salt embayment trend. Although primarily a structural trap, local salt movement at Atkinson Island and its sister field Cedar Point, effect reservoir sand distribution. The Upper Frio Formation has reservoir sand members referred to as the Frio A, Frio B and Frio C sands. These sands represent the uppermost fining upward channel sands and reworked sand bodies. The reservoir has a strong water drive component. Complex stratigraphy provides the potential for compartmentalized reservoir sands. These individual productive sands will not have been drained by the current well density at Atkinson Island. Further detailed work will define future economic oil accumulations.

Seismic

Linc realized that the original 7 square mile 3D dataset across Cedar Point/Atkinson Island covered only a limited area and was poorly processed, resulting in a dataset that would not adequately image and resolve the complex faulting across the structure. In early 2013, Linc increased its licensed 3D seismic volume to 21 square miles and reprocessed the data in several different formats including a high resolution Bandwidth Extension volume. This reprocessing has been a key element in unraveling the complexly faulted geologic picture and enabling the identification of new prospects at updip to pay locations and in previously unrecognized and undrilled fault blocks. This detail, along with seismic attributes such as amplitude (AVO), will aid in future development of the field.

The 3D seismic data at Cedar Point/Atkinson Island is part of a large seismic evaluation of the Galveston Bay area in the 1990's. In 2005, Western Geco offered the industry a merged data set referred to as Galveston Bay EMerge1. The previous operator acquired portions of the data set covering Linc's properties. Subsequently, Linc reprocessed the data at Cedar Point/Atkinson Island Field.

Operational Overview

Atkinson Island consists of 4 producing and 13 inactive wells. All of the wells are produced using gas lift. Gas, oil and water is gathered onshore to a central facility utilizing a network of pipelines. Oil is sold at the central tank batteries utilizing trucks. Gas is compressed and transported to interconnection to Enterprise Intrastate Pipeline. Saltwater is disposed of utilizing two onsite disposal wells. Atkinson Island and Cedar Point fields are processed and gathered together. The offshore facilities consist of two offshore platforms that gather all of the wells and then are transported to the central facility through new 10", 8" and 6" pipelines.

4. Cedar Point

- Operator: Linc
- WI/NRI: 100%/84%
- Acreage: 1,280 gross (1,280 net)
- 3D seismic: 21 sq. mi.

History
Cedar Point field, over 75 years old, is situated in the heart of three producing trends; the Miocene, Frio, and Vicksburg; and is pushing the limits of the Yegua trend. Cedar Point was discovered in 1938 by the Standard Oil Company of Texas. To date over 100 wells have been drilled by several different companies in the 4 square miles around Cedar Point field. The Miocene, Frio and Vicksburg have remaining infill drilling opportunities. The Vicksburg and Yegua, below 7,500 feet remains under-exploited.

The field was discovered using the Torsion Balance technique which measures the second derivatives of gravity force. The equipment was floated in the bay and a survey conducted in search of salt bodies. This instrument was the key to locating the hidden salt domes in the new exploration frontier of bay waters along the Gulf Coast. This field was the first discovery on the Texas coast to be in a bay. Once the gravity survey was acquired and interpreted by Standard of Texas, they conducted reflection seismograph surveys ('2D' seismic data) and mapped areas for drilling.

The discovery well was the Standard of Texas and Salt Dome Oil Corporation #1 State Tract 118, which was completed in to the top of the Frio on February 12, 1938. The initial production, from perforations at about 6,000' was 642 BOPD on ¼" choke with a tubing pressure of 990# - the gravity of the oil was 36.2°.

Fourteen years after the Frio discovery, Standard of Texas drilled the #12 State Tract 118 in search of deeper pool oil. This #12 well was the discovery well for the Vicksburg at about 7,250 feet. This well came on at a rate of 168 BOPD on a 1/8" choke with a shut in pressure of 1,175# with gravity of 37.2°. Finally, the Miocene was a behind pipe opportunity that had its own targeted drilling program begin in the mid 1950's.

In spite of the large number of wells in the area, exploration opportunities still exist today. These opportunities present themselves for several reasons: the leases were held mostly by large companies seeking areas of less complex geology and the perceived chance of larger accumulations elsewhere. Therefore exploration plays were not made on held by production acreage.

It is only within the last decade that 3D seismic data has been available across this field. The former operator of the field acquired seven square miles of the 3D seismic data approximately two years before selling the asset to Linc. Linc had a two-fold approach to the available 3D seismic data: 7 square miles was not enough to adequately map the feature and the data was poor in quality. To remedy this Linc licensed 20 square miles of data and sought out and found a seismic vendor to reprocess the data using modern 3D algorithms. As a result of this reprocessed seismic, additional prospects were identified and a successful drilling program was commenced in 2013.

Geology

The Houston Delta System, in which Cedar Point Field is located, is dominated by two large ancestral river systems with enough energy and sand to build prograding deltas that provide sand–rich stratigraphic intervals in the Miocene and Frio sections across the Galveston Bay area. The Cedar Point Field is a complexly faulted four-way dipping anticlinal structure that develops over a deep seated salt diapir. The faulting is identified by detailed log correlations and 3D seismic data. The faulting strikes generally north-south and has compensating antithetic relief faults. Fault throws are generally 100-200 feet. The Miocene, Frio, and Upper Vicksburg sandstone reservoirs have between 25-33 % porosity and 500-1000 millidarcy permeability. The reservoirs all have a very active water drive mechanism during production.

Seismic

See Atkinson Island seismic discussion above.

Operational Overview

Cedar Point consists of 15 producing and 32 inactive wells. All of the wells are produced using gas lift. Gas, oil and water is gathered on shore to a central facility utilizing a network of pipelines. Oil is sold at the central tank batteries utilizing trucks. Gas is compressed and transported to interconnection to Enterprise Intrastate Pipeline. Saltwater is disposed of utilizing onsite disposal wells. Atkinson Island and Cedar Point fields are processed and gathered together. The offshore facilities consist of two offshore platforms that gather all of the wells and then are transported to the central facility through new 10”, 8” and 6” pipelines.

5. Port Neches

- Operator: Linc
- WI/NRI: 100%/83%
- Acreage: 3,802 gross (3,802 net)
- 3D seismic: 37 sq. mi.

History

Port Neches field was discovered with the use of torsion balance, refraction seismograph, and the observation of surface gas seeps. The Texas Company drilled, in May 1929, the H. J. Kuhn Well No. 1, encountering over 20 feet of gross pay with a flow rate of 1,515 BOPD from the Miocene B-2 Sand at approximately 3,140 feet. Since the discovery of the field, there have been over 190 development and exploration wells drilled and produced from 54 individual productive horizons located on Linc's held by production leases. After the Kuhn Well No. 1 was drilled in May 1929, a step-out well, the Polk "A" No. 1, was drilled in December of the same year, coming in at 1,700 BOPD. The Polk A-1 well produced until May of 1969 from the B-2 Sand, accumulating 963 MBO and 266 MMCF. Activity came to a standstill until 1932, when four wells were drilled. The 1930s and 1940s saw a surge of activity that resulted in 35 wells drilled in the 1930s and 39 drilled in the 1940s. The majority of these wells were completed in the interval between 2,100' (A Sands) and 4,600' (E Sands). It was not until the discovery of Marginulina sand production in the Texaco Polk "B" Well No. 2 in August of 1934 that allowed for deeper oil production. This well was completed from perforations at 5,871'-5,923' at 462 BOPD. The cumulative production through 1973 was 840 MBBLS and 777 MMCF. Nine Marginulina offsets were drilled to develop this deeper sand from 1934 to 1939, and six in the early 1940s.

Geology

Production is from Pliocene through lower Frio Hackberry sands trapped over a piercement-type salt dome located within the Houston salt embayment trend. Port Neches field produces from structural/stratigraphic traps formed within the Pliocene, Miocene and Frio sedimentary column which both overlies and is on the flank of the Bessie Heights salt diapir. The "dome" is in reality a salt tongue that is connected with the Orange dome salt diapir approximately ten miles to the northeast. There are gas productive sands in the Pliocene starting at 1,500 feet, the major productive section starts at approximately 2,100 feet in the Miocene "A" sands and ends in the lower Frio Hackberry sands at approximately 9,000 feet.

Seismic

The Linc-licensed 37 square mile 3D data that covers Port Neches field is cut from a much larger 100 square mile survey that was shot and processed in 1998. Critical acquisition parameters are: 2.5 lb. charges at a depth of 50 feet with a maximum far offset of about 34,000 feet, which is optimal for structural configuration determinations and gleaning rock properties in the geological section away from the salt flanks. The 37 square miles selected by Linc which covers the heart of the lease acreage, takes advantage of the structural information gleaned from the larger data set without having to license the entire survey even where it does not cover Linc leases. State-of-the-art Prestack Time Migration processing was performed by Matrix Geophysical in 2009 with nine different data volumes available for analysis. The data licensed by Linc has enabled the production of a fairly reliable image of the structure around the flanks of the dome. Since the geometry of the dome as documented by well data is quite complex, with structural dips up to 80 degrees, the seismic data and well data must be analyzed together to yield reliable maps.

Operational Overview

Port Neches consists of 12 producing and 35 inactive wells. All of the wells are produced using gas lift. Gas, oil and water is gathered onshore to a central facility utilizing a network of pipelines. Oil is sold at the central tank battery utilizing trucks. Gas is compressed and used for gas lift. Saltwater is disposed of utilizing two onsite disposal wells located in the bay. The offshore facilities consist of one barge that gathers all of the wells and then transports the oil to the central facility onshore.

6. Hoskins Mound

- Operator: Linc
- WI/NRI: 100%/72%
- Acreage: 2,500 gross (2,500 net)
- 3D seismic: 40 sq. mi.

History

Oil was discovered by The Texas Company (later Texaco) at Hoskins Mound in 1903. Production was established from caprock formations but deeper flank drilling was unsuccessful (and would be considered quite shallow today). In 1922 The Texas Company granted a sub-lease to the Freeport Sulphur Company and the field became a major source of elemental sulphur. As a result, oil development was largely abandoned until Texaco began developing the field in the 1960s.

Primary field development took place in the 1960s when Texaco drilled approximately 118 wells on the dome and produced approximately 8.5 MMBBLS from the shallow Miocene before ceasing operations. Subsequently, the lands were used as a Texaco corporate retreat. The surface rights over the field were purchased by The Nature Conservancy and later the Fish and Wildlife Service and then made part of the Brazoria National Wildlife Refuge. However, Texaco (now Chevron) maintained mineral rights and subsurface development rights. This relationship has been a model of cooperation between resource development and wildlife protection.

Chevron farmed-out an interest in the field to Palaura, and in 1998 a proprietary 100 square mile 3D seismic program was acquired by Palaura and the rights to drill were then sold to XTO and Range Resources. Subsequently, this interest in the field was acquired by another operator in 2007. This operator sold the 3D seismic data to a seismic acquisition and processing firm. The 3D data was subsequently reprocessed and Linc purchased the field in the fall of 2011, and 40 square miles of the 3D data in 2012.

Each well completion earns a 40 acre square, limited from the surface to the completed depth. The entire farm-out area is held with one operation every six months. The work commitments in the farm-out can be satisfied by new drilling or by workovers. Consent from Chevron must be obtained to operate and receive farm-out rights. Chevron owns a preferential right on the producing wells and has a right to participate at 35% on additional wells. However, historically, Chevron has non-consented on new wells. Linc owns rights between 65% and 100% working interest in the Miocene and Discorbis for new wells and between 65% and 100% in recompletions, and 100% in the caprock.

Geology

Hoskins Mound is a typical Gulf Coast salt dome. The surface expression is low topographic relief, roughly circular in outline and characteristic of the intrusion of a salt plug into the overlying Tertiary and older formations found in this region. The salt is capped by anhydrite and limestone, with commercial deposits of sulphur, which were mined early in the dome's exploitation. The general elevation of the surrounding prairie is less than 25 feet above sea level.

The field's primary production is from Miocene age oil sands on the flank of the dome. Additional potential exists in the shallower caprock material and the deeper Discorbis section. The dome, like other domes on the Gulf Coast, exhibits lateral faults radiating from the dome, which segment the field into a myriad of reservoirs. In terms of the development agreement, Linc has rights to develop the interval from the shallow Miocene down to and including the Discorbis gas sand at approximately 6,500 feet. Each Lower Miocene well on this dome is in a separate fault block with an expected drainage area of two to seven acres. Wells typically have high initial oil rates, without significant gas, due to strong water drives. Once the water leg reaches the wellbore, production typically declines rapidly thereafter. Therefore, it can be advantageous to increase the amount of oil that a well can produce daily without having any apparent effect on the ultimate recovery.

The historical primary pay section in the Hoskins Mound Field is the BM-1 through the BM-3 interval. These sands generally show porosity of 35% and a collective net pay thickness of about 30 feet. Moreover, due the strong water drive it is anticipated that recovery efficiency of the reservoirs would be 40% or greater. Additional pay sands have been found in the shallower M2 and M4 and M5 series sands. These sands have yielded good results in Linc's drilling program, with net pay sands up to 65 feet thick with up to two pay sands in a well. Also, approximately 300 feet below the BM-3 sand is the Discorbis sand, which has additional potential for the field.

Seismic

Linc has under license 40 square miles out of a much larger Seitel 3D survey. The data licensed by Linc is shaped to capture deeper wells far off the flanks of the dome, thus allowing for good ties to the seismic. The data is time migrated and has not been depth migrated.

Operational Overview

Hoskins Mound consists of 10 producing and 11 inactive wells. All of the wells are produced using gas lift. Gas, oil and water is gathered and sent to a central facility. Oil is sold at the central tank battery utilizing trucks. Gas is compressed and used for gas lift and there is a connection for sales although currently gas lift gas is being purchased. Saltwater is disposed of utilizing one onsite disposal well.

7. Black Bayou

- Operator: Linc
- WI/NRI: 100%/72%
- Acreage: 2,435 gross (2,435 net)
- 3D seismic: 25 sq. mi.

History
The Black Bayou field is located in Cameron Parish Louisiana and has produced over 66 MMBBLS of oil and 60 BCF since its discovery in 1929. The field is associated with a salt dome that pierces Miocene sediments and rises to within approximately 900 feet of the surface. The structure is a salt cored anticline with production derived from the flanks of the dome. Radial faulting from the dome segments reservoirs into discrete production zones. The primary producing reservoirs are Miocene, Camerina and Hackberry formations.

Geology
The Black Bayou field is associated with a large salt dome that pierces Miocene sediments and rises to within approximately 900 feet of the surface. The structure is a salt cored anticline with production derived from the flanks of the dome. Radial faulting from the dome segments reservoirs into discrete production zones. The primary producing zones are Miocene, Camerina and Hackberry formations.

Seismic
Linc recently licensed 5 additional square miles of Seitel's Black Bayou 3D seismic to combine with the 20 square miles already licensed. The migrated gathers of this now 25 square mile dataset were reprocessed to properly evaluate AVO responses in the identified Hackberry prospects that Linc is pursuing and analog producing Hackberry horizons.

Operational Overview
Black Bayou consists of 4 producing and 14 inactive wells. All of the wells are produced using rod pumping units driven by electric motors. Very little gas is produced and none is sold. Wells flow to central tank batteries located throughout the field. Oil is sold at these tank batteries utilizing trucks. Saltwater is disposed of utilizing one onsite disposal well.

8. Goose Creek

- Operator: Linc
- WI/NRI: 100%/72%
- Acreage: 18 gross (18 net)

History
Goose Creek field is situated in the heart of three producing trends; the Miocene, Frio, and Vicksburg; and is pushing the limits of the Yegua trend. Goose Creek was discovered in 1906. By 1950 over 760 wells had been drilled by about 75 different companies in the 4 square miles around Goose Creek field. Today, the well count stands at over 1,500.

Though Goose Creek field, over 100 years old, is situated in the heart of three highly productive trends, the Miocene, above 3,000 feet, still has infill opportunities despite having the heaviest concentration of drilling. The Frio, between 3,500 feet and 6,000 feet, has infill and exploration opportunities. The Vicksburg and Yegua, below 5,000 feet, are under-explored wildcat territories.

Geology
Along the Texas Gulf Coast three depositional systems dominated sand and structural development throughout the Cenozoic. In broad terms, these systems, listed northeast to southwest, are known as the Houston Delta System, the Greta/Carancahua Barrier Island/Strand Plain System and the Norias Delta system. The delta systems are dominated by a couple of large ancestral river systems with enough energy and sand to build prograding deltas, with syndepositional faulting creating additional accommodation space for large, sand-rich, stratigraphic intervals. Drilling by several companies in past years have targeted the lower Frio and upper Vicksburg beyond the historical limits of these trends.

The Greta/Carancahua Barrier Island/Strandplain system lies between the two delta systems. The Barrier/Strandplain system is characterized by several low-energy ancestral rivers unable to build large deltas and by aggradational deposits and littoral currents. Locally, sands and/or shales can thicken dramatically on the downthrown side of down-to the-basin syndepositional faults. These expanded sections usually thin basin-ward and can be absent on the crest of the next basinward shale mass and fault system.

The Frio (Cibicides hazzardi) and the upper Vicksburg (Textularia warreni, Lox B) are the exploration targets of future wells in the Goose Creek area. Sequence stratigraphy and eustatic sea level curves predict the environment of deposition of sediments and the relative position of the ancestral shoreline. Lower Frio time began with a large drop of sea level after the upper Vicksburg High Stand. Lower Frio and upper Vicksburg sands are productive along strike with this prospect. Galveston Bay, immediately offshore, experienced a recent period of successful drilling with lower Frio and upper Vicksburg sands as targets.

Published regional studies, discuss the distribution of sands and depositional environments for the Frio and the Vicksburg formations. Neither study predicts the presence of sands at any of the recent discoveries along trend with Goose Creek. In fact, while neither study explicitly predicts the presence of sands, the possibility of their occurrence could be inferred from these studies.

The Vicksburg sand percentage map shows the existing Vicksburg production in Galveston Bay, along with the Goose Creek area, to be basinward of the expected zero sand line. A number of recent primary term tracts, identified in published articles as lower Frio/upper Vicksburg prospects, lie basinward (down dip) of the zero sand line and shelf margin. The contours on the Vicksburg sand Isolith map and Paleogeography map have convex basinward bulges in the vicinity of recent discoveries as well as across the Goose Creek area. These convex bulges suggest the possibility of sand deposition shifting further basinward. Thus the occurrence of sands in the Goose Creek area is predicted. Indeed, these bulges have been harbingers of the sands discovered during the last ten years in Galveston Bay.

Seismic

There is no 3D data available across this field area. Several 2D lines are available that are close to, but not across, existing acreage. Industry discussions of acquiring 3D data across this field have been ongoing, but a survey has not yet been undertaken.

Operational Overview

Goose Creek consists of 6 producing and 12 inactive wells. All of the wells are produced using rod pumping units driven by electric motors. Very little gas is produced and none is sold. Wells flow to central tank batteries located throughout the field. Oil is sold at these tank batteries utilizing trucks. Saltwater is disposed of utilizing one onsite disposal well.

9. Grass Island

- Operator: Linc
- WI/NRI: 100%/78%
- Acreage: 680 gross (680 net)

History
The Grass Island Field is located in inland state waters in Espiritu Santo Bay near Port O'Connor, Texas. The field was discovered in 1976 and has been operated by various entities.

Geology
The field is a simple faulted 4-way closure also with stratigraphic changes draped over a deep-seated shale mass. Extensive mapping has been done on subsurface sand tops. Linc, to date, has not pursued independent and additional mapping of this field. The productive sands in the field are Miocene in age and range in depth from about 3,900' to 5,400' and are all normally pressured. Production commenced in 1978 and since that time, the field has accumulated over 3 MMBBLS and 16 BCF. The production scheme is that of satellite wells flowing into a central production platform where the fluids are separated. Production from the field is strongly dependent upon gas lift. Separate sales lines and onshore facilities exist for the produced oil and gas. Production for this field has been as high as 600 BOPD, 700 MCFPD and 5,000 BWPD.

Seismic
A proprietary and exclusive 3D seismic survey was shot in 1997-98 by then owner, Petro-Guard Production Company. This survey covers the entire bay and the adjacent portions of Matagorda Island. For the development and production of the shallow Miocene sands of Grass Island field this data is not required. The relatively close-spacing of the wells allows development based on subsurface mapping. At this time, the data set remains proprietary to Petro-Guard and as such, there is no 'off-the-shelf' 3D data available across Grass Island Field. The owners have not licensed the data recently.

Operational Overview
Grass Island consists of 10 producing and 13 inactive wells. All of the wells are produced using gas lift on wells offshore in the bay. Gas, oil and water is gathered to a central facility on a barge offshore. Oil is sent onshore to a central facility utilizing a single oil pipeline. Oil is sold at the central tank batteries utilizing trucks. Gas is compressed and used for gas lift. There is a gas sales line available but currently gas lift gas is being purchased. Saltwater is disposed of utilizing three onsite disposal wells located in the bay.

10. Hull/Liberty

- Operator: Linc
- WI/NRI: 100%/88%
- Acreage: 348 gross (348 net)

History
The Hull oilfield is west of Farm Road 770 in eastern Liberty County. Sun Oil Company located a salt dome in the area in 1908, it was 10 years until the Republic Production Company brought in the first producing well at Hull, at 5,000 feet. Production rose from 330 MBBLS in the discovery year 1918, to 8 MMBBLS in 1921.

Production tapered off thereafter. Redevelopment occurred in 1955 when deeper New Hull, was discovered. The original Hull field caused a boom in Hull and Daisetta during the 1930s. This field is productive from Miocene, Frio and Yegua-aged sands.

Seismic
There is no 3D data currently accessible for Linc's acreage. However, a very large combined 3D survey exists in Seitel's database that does cover the field itself and all acreage surrounding Linc's position.

Operational Overview
Hull/Liberty consists of 12 producing and 10 inactive wells. All of the wells are produced using rod pumping units driven by electric motors. Very little gas is produced and none is sold. Wells flow to central tank batteries located throughout the field. Oil is sold at these tank batteries utilizing trucks. Saltwater is disposed of utilizing one onsite disposal well.

11. Aquarium/Moody

- Operator: Linc
- WI/NRI: 100%/73%
- Acreage: 260 gross (260 net)

History
This field is located in the middle of Galveston Island equidistant from the Gulf and the Bay. The field is a faulted four-way closure over a deep-seated feature. The field was discovered using subsurface mapping and 2D seismic lines. Drilling was by directional well to the targeted sands, which in a structurally advantaged position are located beneath Sweetwater Lake.

This field is known officially as Sweetwater Lake Field and was discovered in 1984 by the Seneca Resources #2A Moody Estate. The well was drilled to a total measured depth of 7,270' and was completed in the Miocene D-5 sand between 5,895' and 5,915' for 87 BOPD. This well was followed by two development wells in 1991 which were both completed in the deeper Miocene S-1 sand around 7,150'. The Seneca #3 Moody Estate well was reclassified in 2000 and was declared the 'new field discovery' for Aquarium Field as updated mapping apparently of the S-1 sand showed it to be in a new fault block.

Cumulative production for three wells and four completions is greater than 750 MBBLS and 400 MMCF.

Geology
Production is from Miocene-aged sands shallower than 7,500'. This field is on trend with Frio and Vicksburg production but this interval remains untested in the immediate area.

Seismic
There is no 3D data available across this field area. Several 2D lines are available for purchase.

Operational Overview
Aquarium consists of 2 producing and no inactive wells. All of the wells are produced using rod pumping units driven by electric motors. Very little gas is produced and none is sold. Wells flow to a central tank batteries located in the field. Oil is sold at this tank battery utilizing trucks. Saltwater is disposed of utilizing one onsite disposal well.

12. Leeville

- Operator: Linc
- WI/NRI: 44%/30%
- Acreage: 100 gross (44 net)
- 3D seismic: 10 sq. mi.

History
Leeville Field, located in Lafourche Parish, Louisiana, is a prolific South Louisiana salt dome with 45 reservoirs ranging in depth from 1,400 to 19,000 feet. Leeville was discovered in 1928 and has seen hundreds of wells drilled on and around the structure originally using 2D seismic and well control. In 1997 a major 3D seismic shot was acquired across the field.

Seismic
Linc has licensed 10 square miles of Seitel 3D data across this field. The data are on the edge of a larger survey and because of the salt dome that forms Leeville field and being on the edge of the data, the data quality is relatively poor. The data have been reprocessed using pre-stack depth migration by Seitel.

Operational Overview
Leeville consists of 1 producing and 3 inactive wells. This well is produced using a jet pump driven by a gas engines. Very little gas is produced and none is sold. Well flows to a tank battery in the field. Oil is sold at this tank batteries utilizing trucks. Saltwater is disposed of trucking the water to a disposal site.

13. Umbrella Point

- Operator: Linc
- WI/NRI: 100%/80%
- Acreage: 80 gross (80 net)

History
The Umbrella Point field is located in the Trinity Bay portion of Galveston Bay in Chambers County. Water depth ranges from 8'-12'. This field is a faulted deep-seated dome. First production was in 1957 from a Frio aged sand, called the F-5, which had an IP rate of 190 BOPD and accumulated 82 MBBLS in a one-year life. The field has seen nearly constant activity to the present day, with over 180 perforated reservoirs.

The mainstay of development has been the Miocene and Frio intervals, containing 25 pay sands. Production ranges from 1,800' down to 12,600'. Linc operates the well with the deepest perforations. The deep perforations are a result of the latest phase in development which began in 1997 with the discovery of Vicksburg-aged reservoirs. These completions are in sands identified by the microfossil Gyrodyna K. (this sand interval has been encountered in Atkinson Island field several miles to the northwest but to this day remains an undrilled wildcat target).

Operational Overview
Umbrella Point consists of 2 inactive wells and 1 saltwater disposal well. All of the wells will be produced using gas lift. Gas and oil will be gathered on shore to a central facility utilizing a network of pipelines. Oil will be sold at a central tank batteries utilizing trucks. Gas is compressed offshore and used for gas lift and any surplus will be transported onshore to an interconnection to Kinder Morgan and sold. Saltwater will be disposed offshore in the disposal well.

QUALIFICATIONS

The technical person responsible for preparing the estimates presented herein meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards) and the SGX Mainboard Listing Rules for mineral, oil, and gas companies.

This report has been supervised by Mr. Rodger L. Walker, P.E. HPESI does not have or expect to receive any direct or indirect interest in the securities of Linc Energy, Ltd. its parents, or its subsidiaries. Rodger L. Walker, P.E. is an Associate Director of Engineering with HPESI. He graduated from Virginia Tech in 1974 with a Bachelor of Science Degree in Mining Engineering followed by graduate level work at Virginia Tech. He has worked in various petroleum engineering capacities in the petroleum industry since 1976. He has conducted reservoir engineering appraisals for HPESI since 1997 and has been a Director since 2006. He is a member in good standing of the Society of Petroleum Engineers (SPE) and is licensed and registered with the Texas Board of Registration for Professional Engineers (No. 53835). He is the person in responsible charge in preparation of this report and is a Qualified Person under the SGX Mainboard Listing Rules.

HPESI CREDENTIALS

HPESI was founded in 1980 and incorporated in 1982 and has an office at 2100 Ross Avenue, Suite 600, Dallas, Texas 75201. HPESI performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-002950. We have provided services and expertise to hundreds of clients engaged in various aspects of the petroleum industry. The firm has highly experienced professionals and support staff who have conducted reserves evaluations in various countries of the world and in most of the producing areas of the United States. These evaluations and expert testimony have been accepted by major producing companies, independent operators, banks and other financial institutions, pipeline companies, state and national regulatory bodies, trustees, attorneys, courts of law, arbitrators and investors as the basis for reserves disclosures and decisions regarding such matters as project financing, unitizations, equity re-determination, acquisitions, divestitures, public offerings of equity or debt instruments, development programs, enhanced recovery projects, facilities commitments, negotiated settlements, cooperative agreements, leasing, bidding, bankruptcies and lawsuits.

INDEPENDENCE

We are independent petroleum engineers and geologists. With respect to Client; we do not own an interest in the properties or Stock of Linc Energy, Ltd. that are the subject of this report nor are we employed on a contingent basis.

FEES

Fees for conducting this independent technical assessment are being charged to Client based on actual man-hours expended and our current standard billing rate schedule, plus associated out-of-pocket costs.

DISCLAIMERS

In this unqualified audit of Linc's Reserves and Resources, HPESI noted several variances from our internal estimations including forecast differences and the lease operating expenses. However, these differences, in aggregate, did not exceed the 10 percent tolerance of auditing standards.

The Proved Reserves and Prospective Resources presented in this report are estimates only and should not be construed as being exact quantities. The Reserves may or may not be actually recovered; and, if recovered, the revenues therefrom and the actual costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the product prices and the costs incurred in recovering these Reserves may vary from the price and cost assumptions in this report. Because these estimates are based on existing governmental regulations, changes could affect the ability to recover these Reserves and Resources. In any case, quantities of Reserves and Resources may increase or decrease as a result of future operations.

Reserves and Resources estimates for individual properties included in this report are only valid when considered within the context of the overall report and should not be considered independently. The future net income and net present value estimates contained in this report do not represent an estimate of fair market value.

All information pertaining to the operating expenses, prices, and the interests of Linc in the properties appraised has been accepted as represented. It was not considered necessary to make a field examination of the appraised properties. Data used in performing this appraisal were obtained from Linc, public sources, and our own files. Supporting work papers pertinent to the appraisal are retained in our files and are available to you or designated parties at your convenience.

It was beyond the scope of this HPESI report to evaluate the potential environmental liability costs from the operation and abandonment of these properties. In addition, no evaluation was made to determine the degree of operator compliance with current environmental rules, regulations, and reporting requirements. Therefore, no estimate of the potential economic liability, if any, from environmental concerns is included in the forecasts presented herein.

HPESI is independent with respect to Linc as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

GENERAL INFORMATION

Attached are summary tables of economic analysis of predicted future performance. Other tables identify the properties appraised with summary Reserves and Resources and the economic factors applicable to the Reserves. A list of tables is included.

We appreciate this opportunity to have been of service and hope that this report will fulfill your requirements.

[Remainder of page intentionally left blank. Signature page follows.]

Respectfully submitted,

Haas Petroleum Engineering Services, Inc.

F-0002950

Rodger L. Walker, P.E.

APPENDIX A		
In March 2007, the SPE Board approved a new system for definining hydrocarbon reserves and resources. The updated definitions were developed over two years in coordination with WPC, AAPG, and SPEE. The tables below were taken from the SPE publication titled "Petroleum Resources Management System" and contain the updated reserves definitions and guidelines.		
RESERVES STATUS DEFINITIONS AND GUIDELINES		
Status	Definition	Guidelines
Developed Reserves	Developed Reserves are expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.	Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production.
		In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Undeveloped Reserves are quantities expected to be recovered through future investments:	(1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.
RESERVES CATEGORY DEFINITIONS AND GUIDELINES		
Category	Definition	Guidelines
Proved Reserves	Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that: 1) The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. 2) Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves	Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.
Possible Reserves	Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	(See above for separate criteria for Probable Reserves and Possible Reserves.)	The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisonsto results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

LINC ENERGY LTD

(the "Company")

Independent Qualified Person's Declaration and Consent Statement

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DECLARATION

I, Rodger L. Walker, confirm that in relation to the enclosed qualified person's report ("Audit of Certain Oil and Gas Interests Prepared by Linc Gulf Coast Petroleum, Inc. located in Louisiana and Texas, as of June 30, 2015") dated July 28, 2015 (the "Report"):

- I am an independent qualified person ("Independent Qualified Person") in accordance with the requirements of the listing manual ("Listing Manual") of Singapore Exchange Securities Trading Limited (the "SGX-ST"). In particular, I confirm that I have satisfied the requirements of Rule 210(9)(b) of the Listing Manual as follows:

  (a) I am not a sole practitioner;
  (b) I am a director of Haas Petroleum Engineering Services, Inc. in relation to the production of the Report;
  (c) I am personally, and Haas Petroleum Engineering Services, Inc.'s partners, directors, substantial shareholders and their associates are, independent of the Company, its directors and substantial shareholders, its advisers and their associates;
  (d) I, as well as Haas Petroleum Engineering Services, Inc.'s partners, directors, substantial shareholders and their associates, do not have any interest, direct or indirect, in the Company, its subsidiaries or associated companies and will not receive any benefits, direct or indirect, other than remuneration paid in connection with the Report; and
  (e) the remuneration paid to me or Haas Petroleum Engineering Services, Inc. in connection with the Report is not dependent on the attainment of any stipulated results or findings of the Report; and

- in preparing the Report, I took into account all relevant information supplied to me by the directors of the Company.

CONSENT STATEMENT

I, named as the Independent Qualified Person, hereby consent to the inclusion of all references to my name in the form and context in which they appear in the Report, the Declaration and this Consent Statement, and the submission of the same to the SGX-ST and/or release by the Company on SGXNET.

	07/30/2015
Signature of Independent Qualified Person	Date
State of Texas Professional Engineer	53835
Professional Society Affiliations and Membership *(insert organisation name)*	Membership Number
	J. Thaddeus Toups, Dallas – Dallas, Texas
Signature of Witness	Print Witness Name and Residence (eg. Town/Suburb)

QUALIFIED PERSON'S REPORT

ON

LINC ENERGY PETROLEUM (WYOMING), INC.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

June 30, 2015

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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CASHFLOW OUTPUT

Executive Summary

At the request of Linc Energy, Ltd. (Linc Energy), Ryder Scott Company, L.P. (Ryder Scott) has prepared a Qualified Person's Report ("QPR") which contains an estimate of the proved and possible hydrocarbon reserves, future production and income attributable to certain leasehold interests of Linc Energy as of June 30, 2015. The subject properties are located in the state of Wyoming. The reserves were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on July 30, 2015 and presented herein, was prepared in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved and possible liquid hydrocarbon reserves Linc Energy as of June 30, 2015.

The estimated reserves and future net income amounts presented in this report, as of June 30, 2015 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
Linc Energy (Wyoming), Inc.
As of June 30, 2015

	Total Proved Reserves
Net Remaining Reserves	
Oil/Condensate – Barrels	551,331
Income Data (M$)	
Future Gross Revenue	$31,862
Deductions	20,305
Future Net Income (FNI)	$11,557
Discounted FNI @ 10%	$5,618

SEC PARAMETERS

Estimated Net Reserves and Income Data

Certain Leasehold Interests of

Linc Energy (Wyoming), Inc.

As of June 30, 2015

	Total Possible Reserves
Net Remaining Reserves	
Oil/Condensate – Barrels	66,892,593
Income Data (M$)	
Future Gross Revenue	$3,863,336
Deductions	2,455,450
Future Net Income (FNI)	$1,407,886
Discounted FNI @ 10%	$422,784

Liquid hydrocarbons are expressed in standard 42 gallon barrels. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. The program was used at the request of Linc Energy. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, development costs. The other deductions represent the cost to purchase CO2 for the proposed enhanced oil recovery projects in the Big Muddy Field and South Glenrock Field (B Unit). The future net income is before the deduction state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustments for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for 100 percent of total future gross revenue from proved reserves. Liquid hydrocarbon reserves account for 100 percent of the total future gross revenue from possible reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income (M$) As of June 30, 2015	
Discount Rate Percent	Total Proved	Total Possible
5	$7,492	$761,801
8	$6,233	$534,911
12	$5,121	$333,009
15	$4,529	$229,162

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Summary of Oil and Gas Reserves and Resources

Name of Asset/Country: Linc Energy Petroleum (Wyoming). Inc./United States of America

Category	Gross Attributable to Licence (MMbbl / Bcf)	Net Attributable to Issuer		Remarks
		(MMbbl / Bcf)	Change from previous update (%)	
Reserves				
Oil Reserves				
1P	0.7	0.6	-28.0%	
2P	0.7	0.6	-28.0%	
3P	90.0	67.4	-0.3%	

1P: Proved
2P: Proved + Probable
3P: Proved + Probable + Possible

MMbbl: Millions of barrels
Bcf: Billions of cubic feet

Name of Qualified Person: James L. Baird James L. Baird

Date: July 30, 2015

Professional Society Affiliation / Membership: Colorado Licensed Professional Engineer No. 41521

Property Description
WYOMING OIL AND GAS LEASES

No.	Lease / Tract Name	Lessor	Unit	County	State	Gross Acres	Expiry Date [1]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
1	WYW 163900	ONRR	non unit	Converse	WY	596.40	October 31, 2015	oil and gas	100.00%	83.00%
2	WYW 164691	ONRR	non unit	Converse	WY	200.00	November 30, 2015	oil and gas	100.00%	78.00%
3	WYW 164394	ONRR	non unit	Converse	WY	391.25	September 30, 2015	oil and gas	100.00%	78.00%
4	WYW 164393	ONRR	non unit	Converse	WY	120.00	December 31, 2015	oil and gas	100.00%	78.00%
5	WYW 172991	ONRR	non unit	Converse	WY	640.00	July 31, 2016	oil and gas	100.00%	78.00%
6	WYW 172989	ONRR	non unit	Natrona	WY	160.00	July 31, 2016	oil and gas	100.00%	78.00%
7	WYW 173001	ONRR	non unit	Natrona	WY	2161.43	July 31, 2016	oil and gas	100.00%	78.00%
8	WYW 003035	ONRR	South Cole Creek Dakota	Converse	WY	199.89	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
9	E R McQuaid ET UX	E R McQuaid ET UX	South Cole Creek Dakota	Converse	WY	320.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	73.00%
10	C M Kopp and Mary S Kopp	C M Kopp and Mary S Kopp	South Cole Creek Dakota	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	86.00%
11	C E Kopp and Mildred M Kopp	C E Kopp and Mildred M Kopp	South Cole Creek Dakota	Converse	WY	640.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	86.00%
12	A J Kopp and Lulu Kopp	A J Kopp and Lulu Kopp	South Cole Creek Dakota	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	79.00%
13	Iona M Campbell ET VIR	Iona M Campbell ET VIR	South Cole Creek Dakota	Converse	WY	320.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
14	T R Kopp and Mary Kopp	T R Kopp and Mary Kopp	South Cole Creek Dakota	Converse	WY	280.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	86.00%
15	ST WY 0-2900	WY Office of State Lands and Investments	South Cole Creek Dakota	Converse	WY	600.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
16	George A Leach ET AL	George A Leach ET AL	South Cole Creek Dakota	Converse	WY	320.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
17	Guy Pothe ET UX	Guy Pothe ET UX	South Cole Creek Dakota	Converse	WY	317.50	Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
18	WYW 077076	ONRR	South Cole Creek Dakota	Converse	WY	400.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
19	WYW 002217	ONRR	South Cole Creek Dakota	Converse	WY	40.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
20	ST WY 0-4592	WY Office of State Lands and Investments	South Cole Creek Dakota	Converse	WY	40.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
21	WYW 077837	ONRR	South Cole Creek Dakota	Converse	WY	79.89	Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
22	WYW 077843	ONRR	South Cole Creek Dakota	Converse	WY	1025.52	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
23	Westport Oil and Gas LP - 880	Westport Oil and Gas LP	Big Muddy River- 2nd Frontier	Converse	WY	880.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
24	H C Young ET AL	H C Young ET AL	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%

Property Description
WYOMING OIL AND GAS LEASES

No.	Lease / Tract Name	Lessor	Unit	County	State	Gross Acres	Expiry Date [1]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
25	WYW 162618	ONRR	Big Muddy River- 2nd Frontier	Converse	WY	40.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	86.00%
26	ST WY 05-00269	WY Office of State Lands and Investments	Big Muddy River- 2nd Frontier	Converse	WY	478.95	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
27	ST WY 05-00270	WY Office of State Lands and Investments	Big Muddy River- 2nd Frontier	Converse	WY	400.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
28	ST WY 04-00241	WY Office of State Lands and Investments	Big Muddy River- 2nd Frontier	Converse	WY	600.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
29	WYW 161772	ONRR	Big Muddy River- 2nd Frontier	Converse	WY	160.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	79.00%
30	Ann Obrzut	Ann Obrzut	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
31	Leslie Gay Bolin	Leslie Gay Bolin	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
32	Miner D. Crary Jr.	Miner D. Crary Jr.	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
33	Stephen T Crary	Stephen T Crary	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
34	Horace L Crary	Horace I Crary	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
35	KGN-Susan Beauchamp Davidge	KGN-Susan Beauchamp Davidge	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
36	KGN-Phyllis Davidge Knapp	KGN-Phyllis Davidge Knapp	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
37	Arthur E Symons	Arthur E Symons	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	82.00%
38	KGN- Mary Lousie McGregor	KGN- Mary Lousie McGregor	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
39	KGN- Richard Burch Eyre	KGN- Richard Burch Eyre	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
40	KGN- Debra Cecile Yerkes Brambley	KGN- Debra Cecile Yerkes Brambley	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
41	KGN- Thomas Crary Davidge III	KGN- Thomas Crary Davidge III	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
42	KGN- Ronald Holm Davidge	KGN- Ronald Holm Davidge	Big Muddy River- 2nd Frontier	Converse	WY	800.97	Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
43	KGN- William Henry Davidge	KGN- William Henry Davidge	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
44	KGN- Robert G Stoughton Marlowe	KGN- Robert G Stoughton Marlowe	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
45	KGN- Lura Crary Griswold	KGN- Lura Crary Griswold	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
46	KGN- Dean Gifford Davidge	KGN- Dean Gifford Davidge	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
47	KGN- Chandler Y Keller	KGN- Chandler Y Keller	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
48	Carolyn L Ridley ET AL	Carolyn L Ridley ET AL	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	82.00%

Property Description
WYOMING OIL AND GAS LEASES

No.	Lease / Tract Name	Lessor	Unit	County	State	Gross Acres	Expiry Date [1]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
49	Pamela Dugan	Pamela Dugan	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
50	Chris Eyre	Chris Eyre	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
51	KGN-Mary Shifflet Yerkes	KGN-Mary Shifflet Yerkes	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
52	KGN- Suzanne Stoughton	KGN- Suzanne Stoughton	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
53	KGN -George H Anderson	KGN -George H Anderson	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
54	KGN- Winifred Crary Valens Trust	KGN- Winifred Crary Valens Trust	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
55	KGN- Jean K Carros	KGN- Jean K Carros	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
56	WYW 079294	ONRR	Big Muddy River- 2nd Frontier	Converse	WY	240.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
57	The Northwest Oil Company	The Northwest Oil Company	Big Muddy River- 2nd Frontier	Converse	WY	40.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
58	ST WY 00-1822	WY Office of State Lands and Investments	Big Muddy River- 2nd Frontier	Converse	WY	1120.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
59	WYW 085311	ONRR	Big Muddy River- 2nd Frontier	Converse	WY	33.50	Held by unit / upon permanent cessation of production	oil and gas	100.00%	72.00%
60	Westport Oil and Gas LP - 800	Westport Oil and Gas LP	Big Muddy River- 2nd Frontier	Converse	WY	800.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
61	Westport Oil and Gas LP - 160	Westport Oil and Gas LP	Big Muddy River- 2nd Frontier	Converse	WY	160.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
62	KGN Mineral Trust DTD 09/09/98	KGN Mineral Trust DTD 09/09/98	Big Muddy River- 2nd Frontier	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	82.00%
63	Fenex Oil	Fenex Oil	Big Muddy River- 2nd Frontier East Big Muddy Unit	Converse	WY	160.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
64	Suasanne B Brubaker	Suasanne B Brubaker	Big Muddy River- 2nd Frontier East Big Muddy Unit	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
65	Fenex Oil	Fenex Oil	Big Muddy River- 2nd Frontier East Big Muddy Unit	Converse	WY	40.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
66	Susanne B Brubaker	Susanne B Brubaker	Big Muddy River- 2nd Frontier East Big Muddy Unit	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
67	Susanne B Brubaker	Susanne B Brubaker	Big Muddy River- 2nd Frontier South Glenrock A unit	Converse	WY	120.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
68	Glenrock Sheep Company	Glenrock Sheep Company	Big Muddy River- 2nd Frontier	Converse	WY	200.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	79.00%
69	ST WY 0-4392	WY Office of State Lands and Investments	South Glenrock A Unit	Converse	WY	160.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
70	Gus Engleking ET AL	Gus Engleking ET AL	South Glenrock A Unit	Converse	WY	320.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
71	WYW 170073	ONRR	South Glenrock A Unit	Converse	WY	36.77	Held by unit / upon permanent cessation of production	oil and gas	100.00%	80.00%
72	ST WY 0-3459	WY Office of State Lands and Investments	South Glenrock A Unit	Converse	WY	40.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%

Property Description
WYOMING OIL AND GAS LEASES

No.	Lease / Tract Name	Lessor	Unit	County	State	Gross Acres	Expiry Date [1]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
73	ST WY 0-4393	WY Office of State Lands and Investments	South Glenrock A Unit	Converse	WY	80.48	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
74	ST WY 0-9125	WY Office of State Lands and Investments	South Glenrock A Unit	Converse	WY	120.14	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
75	ST WY 0-4329	WY Office of State Lands and Investments	South Glenrock A Unit	Converse	WY	160.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
76	ST WY 0-9299	WY Office of State Lands and Investments	South Glenrock A Unit	Converse	WY	440.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
77	ST WY 0-6876	WY Office of State Lands and Investments	South Glenrock A Unit	Converse	WY	120.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
78	ST WY 0-23543	WY Office of State Lands and Investments	South Glenrock A Unit	Converse	WY	320.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
79	WYW 0610	ONRR	South Glenrock A Unit	Converse	WY	160.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
80	ST WY 0-4063	WY Office of State Lands and Investments	South Glenrock A Unit	Converse	WY	122.82	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
81	ST WY 0-7787	WY Office of State Lands and Investments	South Glenrock	Converse	WY	800.00	Held by unit / upon permanent cessation of production	oil and gas	94.7361%	78.00%
82	S M Anderson ET AL	S M Anderson ET AL	East Big Muddy Unit South Glenrock A	Converse	WY	447.72	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
83	C Leonard Smith	C Leonard Smith	East Big Muddy Unit South Glenrock A	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
84	Lincoln Petroleum Company	Lincoln Petroleum Company	East Big Muddy Unit South Glenrock A	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
85	WYW 072335	ONRR	East Big Muddy Unit	Converse	WY	40.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
86	Fenex Oil	Fenex Oil	East Big Muddy Dakota	Converse	WY	150.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
87	Continental Oil Co	Continental Oil Co	South Glenrock B Unit	Converse	WY	89.70	Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
88	ST WY 0-6117	WY Office of State Lands and Investments	South Glenrock B Unit	Converse	WY	903.36	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
89	ST WY 0-7790	WY Office of State Lands and Investments	South Glenrock B Unit	Converse	WY	959.78	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
90	Chicago & N Western Transportation	Chicago & N Western Transportation	South Glenrock B Unit	Converse	WY	17.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
91	V R Ranch	V R Ranch	South Glenrock B Unit	Converse	WY	1612.16	Held by unit / upon permanent cessation of production	oil and gas	100.00%	85.00%
92	George W Kelly ET AL	George W Kelly ET AL	South Glenrock B Unit	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	77.00%
93	Louise M Bruns	Louise M Bruns	South Glenrock B Unit	Converse	WY	120.00	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
94	Edward Walkinshaw ET UX	Edward Walkinshaw ET UX	South Glenrock B Unit	Converse	WY	938.41	Held by unit / upon permanent cessation of production	oil and gas	100.00%	85.00%
95	Charles B Olin ET AL	Charles B Olin ET AL	South Glenrock B Unit	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	98.0208%	77.00%
96	Fred Walkinshaw and Nora Walkinshaw	Fred Walkinshaw and Nora Walkinshaw	South Glenrock B Unit	Converse	WY	76.59	Held by unit / upon permanent cessation of production	oil and gas	98.0208%	80.00%

Property Description
WYOMING OIL AND GAS LEASES

No.	Lease / Tract Name	Lessor	Unit	County	State	Gross Acres	Expiry Date [1]	Use of Property	Working Interest (%)	Net Revenue Interest (%)
97	J L Goodner ET AL	J L Goodner ET AL	South Glenrock B Unit	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	98.0208%	45.00%
98	Clyde M Watts and Albert D Walton	Clyde M Watts and Albert D Walton	South Glenrock B Unit	Converse	WY	197.32	Held by unit / upon permanent cessation of production	oil and gas	98.0208%	77.00%
99	James C Tvaruzek and Elizabeth Tvaruzek	James C Tvaruzek and Elizabeth Tvaruzek	South Glenrock B Unit	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	98.0208%	78.00%
100	Ted Stewart, Gordon Stewart, ET UX	Ted Stewart, Gordon Stewart, ET UX	South Glenrock B Unit	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	55.5079%	43.30%
101	J L Gooder ET UX	J L Gooder ET UX	South Glenrock B Unit	Converse	WY	40.00	Held by unit / upon permanent cessation of production	oil and gas	47.3123%	45.00%
102	Agnes Verner, ET AL	Agnes Verner, ET AL	South Glenrock B Unit	Converse	WY		Held by unit / upon permanent cessation of production	oil and gas	100.00%	79.00%
103	ST WY 0-6048	WY Office of State Lands and Investments	South Glenrock B Unit	Converse	WY	1076.25	Held by unit / upon permanent cessation of production	oil and gas	98.0208%	78.00%
104	WYW 000249	ONRR	South Glenrock B Unit	Converse	WY	237.50	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
105	WYW 070469	ONRR	South Glenrock B Unit	Converse	WY	160.00	Held by unit / upon permanent cessation of production	oil and gas	98.0193%	78.00%
106	ST WY 0-7791	WY Office of State Lands and Investments	South Glenrock B Unit	Converse	WY	640.00	Held by unit / upon permanent cessation of production	oil and gas	98.0208%	78.00%
107	ST WY 0-6049	WY Office of State Lands and Investments	South Glenrock B Unit	Converse	WY	635.88	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
108	ST WY 0-6050	WY Office of State Lands and Investments	South Glenrock B Unit	Converse	WY	699.40	Held by unit / upon permanent cessation of production	oil and gas	100.00%	78.00%
109	ST WY 0-6051	WY Office of State Lands and Investments	South Glenrock B Unit	Converse	WY	921.95	Held by unit / upon permanent cessation of production	oil and gas	98.0208%	78.00%
110	ST WY 0-6052	WY Office of State Lands and Investments	South Glenrock B Unit	Converse	WY	1280.00	Held by unit / upon permanent cessation of production	oil and gas	98.0208%	78.00%
111	Minnie O Moffett	Minnie O Moffett	South Glenrock B Unit	Converse	WY	165.00	Held by unit / upon permanent cessation of production	oil and gas	98.0082%	77.00%
112	William E Barber	William Barber	South Glenrock B Unit	Converse	WY	90.32	Held by unit / upon permanent cessation of production	oil and gas	74.5052%	58.11%

Property Overview

A map of the Linc Energy owned fields which are located near Glenrock, Wyoming, is displayed in Figure 1 below.

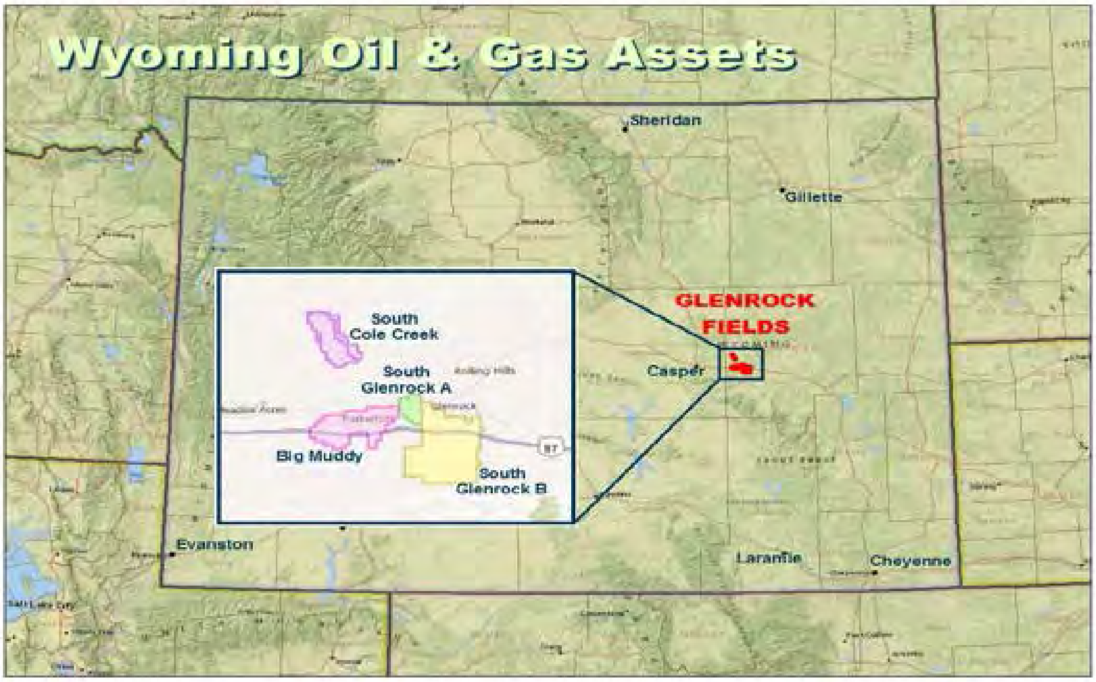

Figure 1: Map of Linc Energy's Wyoming Oil and Gas Assets

On February 25, 2011, Linc announced the acquisition of three producing oil fields in Wyoming's Powder River Basin. The three oil fields were acquired for a total consideration of $20 million from Rancher Energy Corp., a Nevada corporation who filed Chapter 11 bankruptcy. Prior to entering Chapter 11 bankruptcy, Rancher Energy Corp. had acquired the three fields for a total consideration of approximately US $70 million. The Linc Energy acquisition of the Rancher Energy assets was approved by the United States Bankruptcy Court on February 24, 2011 and the effective date of the transaction was March 1, 2011.

The three producing fields purchased from Rancher Energy are Big Muddy, South Glenrock and South Cole Creek. The fields, located 15 miles east of Casper, Wyoming, have combined production of approximately 146.6 million barrels of oil to date from an estimated Original Oil in Place (OOIP) of 466.6 million barrels of oil. The current gross production rate of Linc Energy's Wyoming assets is approximately 190 bopd. The South Glenrock, Big Muddy, and South Cole Creek fields are all currently under secondary production (waterflood) conditions.

Independent reports by NITEC LLC, commissioned by Rancher Energy, indicate that the fields have the potential to increase gross recoverable oil by approximately 80 million barrels from enhanced oil recovery (EOR) techniques utilizing CO_2 flooding operations, over the approximate 20 year production period after initiation of the CO_2 floods. The potential reservoirs that have been evaluated by NITEC LLC to initiate CO_2 flooding operations include Dakota, Upper Muddy, Lower Muddy, and Frontier formations.

Geological Summary

Figures 2 and 3 show the gross thickness and structure map, respectively, in the proximity of Linc Energy's assets. Please note, Linc Energy does not hold interest in the Brooks Ranch area, however it is included on the below maps to show the geological trends in the surrounding areas of Linc Energy's assets.

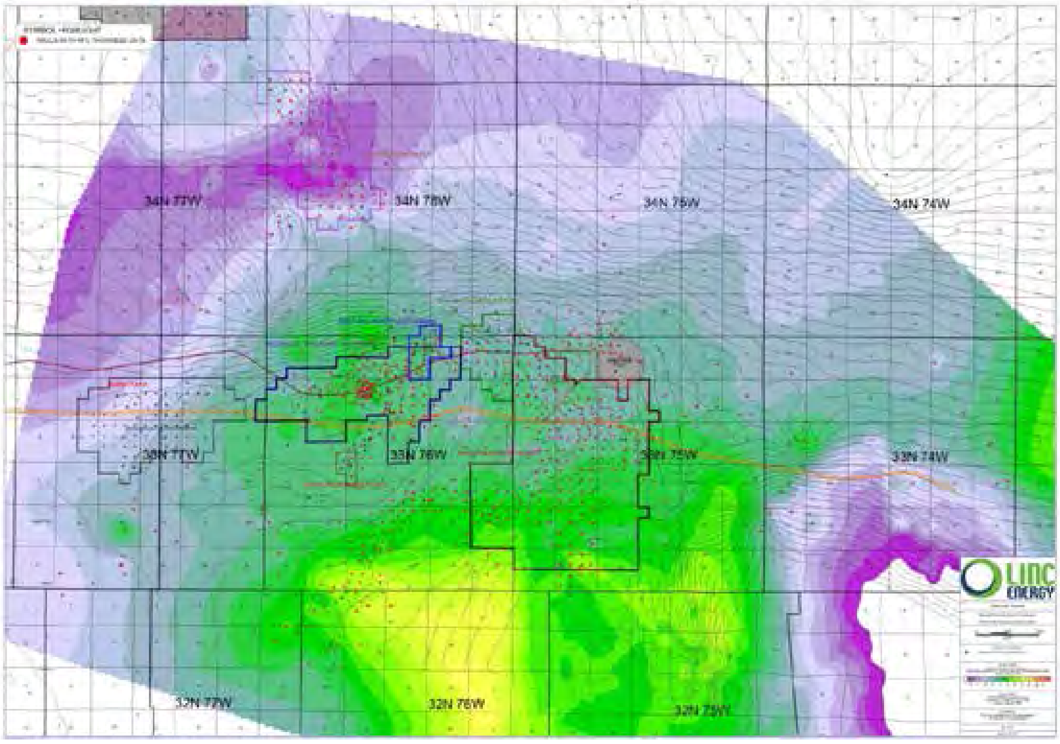

Figure 2: Gross Thickness Map in the Proximity of Linc Energy's Wyoming Oil and Gas Assets

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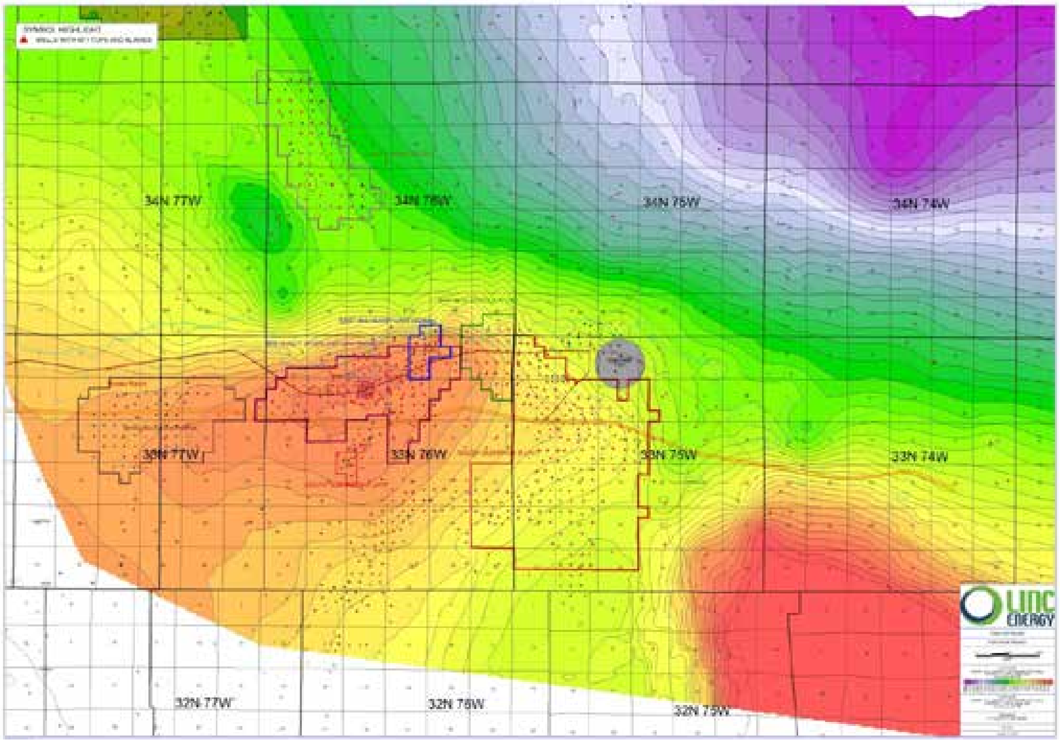

Figure 3: Structure Map in the Proximity of Linc Energy's Wyoming Oil and Gas Assets

South Glenrock B Unit Geology

The Muddy and Dakota formation reservoir rocks at South Glenrock B Unit were deposited as part of low stand system tract during periods of sea level lows. At low sea level, the shelf was exposed allowing fluvial systems to incise into the exposed deep water shales for tens of miles. When sea level rose, the fluvial sands are often reworked into tidal or upper shore face sandstones. As in the case of the Upper Muddy, the channelized sandstone can be constrained by paleo-structures causing sea floor topographic anomalies.

Figures 4 and 5 are type logs for the Dakota and Upper/Lower Muddy sandstones. Figures 6 through 9 are isopach maps for each of the producing sandstones, including the Upper Muddy, Lower Muddy 1, Lower Muddy 2, and Dakota. The channelized character of these reservoirs is apparent in the thickness maps. Trapping mechanisms include both stratigraphic and structural, as the channels drape over plunging structural noses.

Figure 4: Type Log of Dakota Sandstones

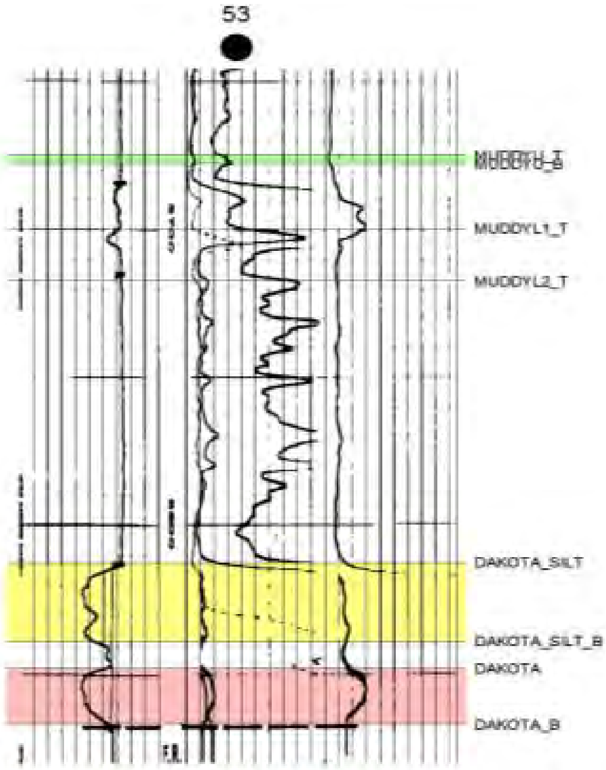

Figure 5: Type Log of Upper Muddy and Lower Muddy 1-2 Sandstones

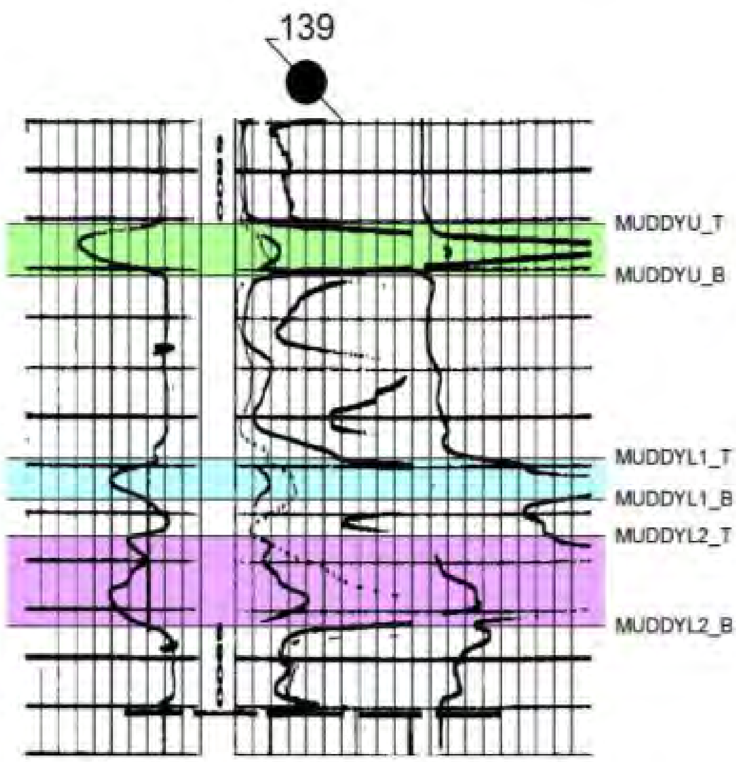

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Figure 6: Isopach map of the Upper Muddy Sandstone

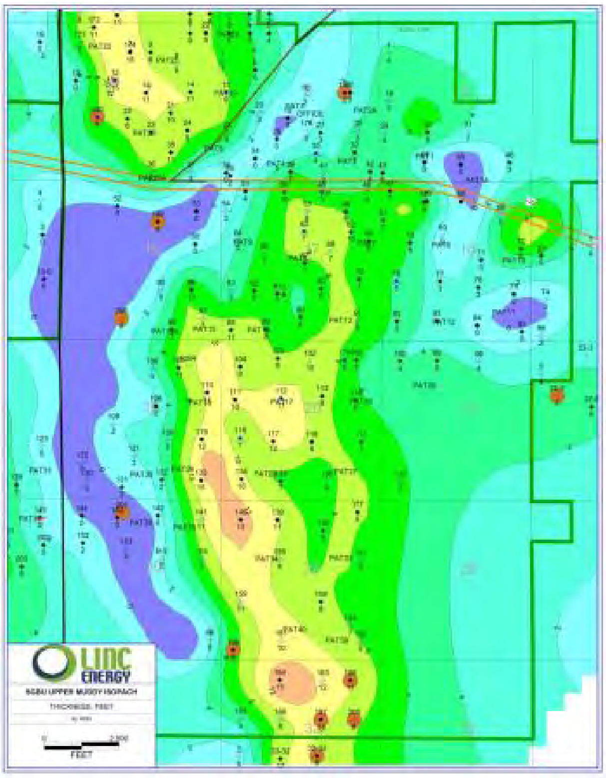

Figure 7: Isopach map of the Lower Muddy 1 Sandstone

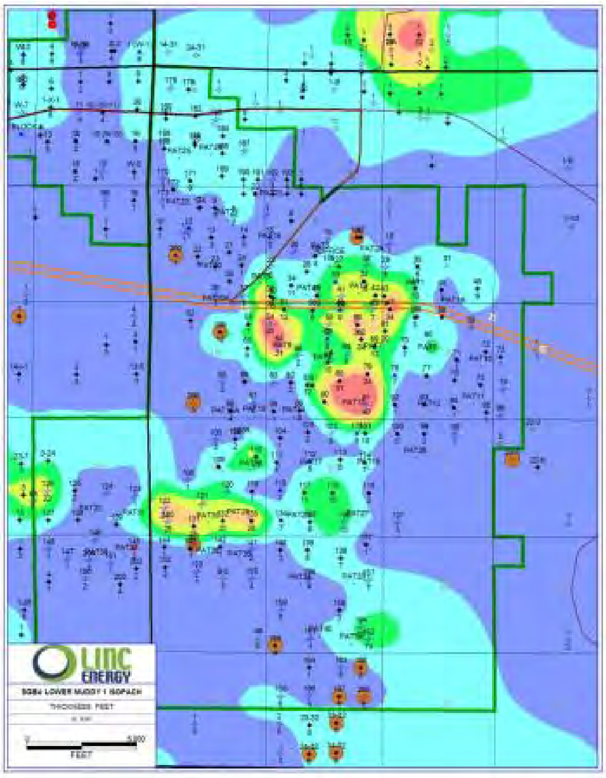

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Figure 8: Isopach map of the Upper Muddy 2 Sandstone

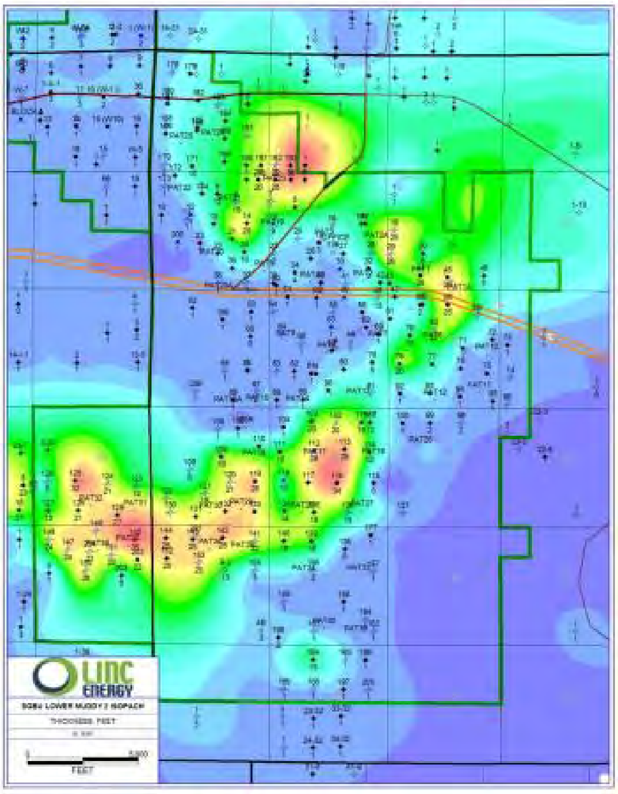
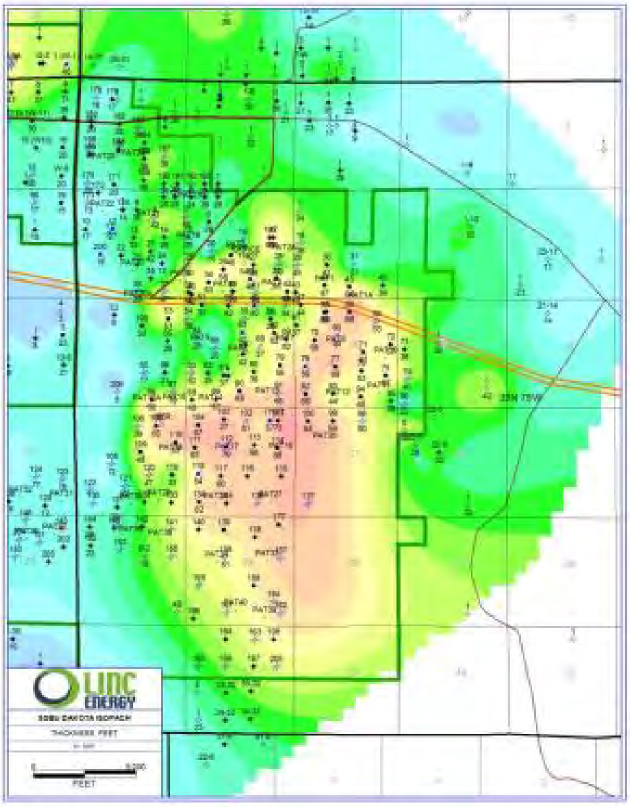


Figure 9: Isopach Map of the Dakota Sandstone



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Big Muddy Geology

The structural geology of the Big Muddy field is characterized by an asymmetric anticline trending ENE-WSW in the southwest flank of the Powder River Basin. The dips on the west, south, and east flanks are gentle (2 to 4 degrees) while dips to the north are 15 to 20 degrees or steeper. The anticlinal fold is believed to be cored by granitic basement, probably formed by a basin bounding high angle reverse fault. The Upper Cretaceous Steele Shale is exposed and forms the surface with sandstones of the shallower Mesaverde forming low cuestas to the east and south. Direct and indirect evidence (i.e. literature, well fluids response, structure contours, and missing section in logs) indicate some level of faulting and fracturing, especially along the crest of the structure.

The main zones that have been produced from, since the fields inception, are the Shannon, Second Frontier (Wall Creek), and Dakota. There is some scattered production from the "Stray" (Niobrara or Steele shale), as well as other sand benches of the Frontier and the Lakota. Production from the Second Frontier is by far the largest contributor.

The Shannon sand is a marine sand of arguable origin encased in marine shale. It is found at a depth of approximately 1000 feet and averages approximately 15 feet gross thickness with 10 - 20% porosity. Total estimated production from the Shannon is 2 to 3 MMBO.

The Second Frontier is regionally extensive, well developed regressive marine sandstone deposited in a delta/delta front environment. To a first approximation, it is a blanket sand that covers the field with a gross thickness of 80 to 90 feet (net approximately 60 to 65 feet) with average porosities in the 17 – 22% range. Total estimated production is at least 32 MMBO.

The productive Dakota sand is a fluvial "channel sand" that cuts into older marine or estuarine deposits. The fluvial nature of these sands creates a stratigraphic dimension to the trapping mechanism. Porosities average 15 – 20% and the total estimated production from the Dakota is almost 15 MMBO. Data for the Lakota is sparse but it is also thought to be a fluvial sand deposit and/or a braided stream system. Total estimated production for the Lakota is approximately 2 MMBO and it generally produces a considerable amount of water.

Structural closures are the primary control for production from the Shannon and Frontier. Production from the "stray" is probably controlled by localized fracture systems. The Dakota and Lakota sands are lenticular in nature and produce from combined structural/stratigraphic trapping mechanisms. The Second Frontier does not have a common oil/water contact implying possible local influence from faulting, stratigraphy, and/or hydrodynamics.

South Cole Creek Geology

The Dakota formation reservoir rocks at South Cole Creek were deposited as part of low stand system tract during periods of sea level lows. At low sea level, the shelf was exposed allowing fluvial systems to incise into deep water shales for tens of miles. When sea level rose, the fluvial sands are often reworked into tidal or upper shore face sandstones. Two NE-trending Dakota channel systems define the productive reservoir system at South Cole Creek Unit. The well log data for the Lakota formation is limited, therefore no conclusions can be drawn on its distribution and architecture.

Figure 10 is a type log showing both Dakota and Lakota sandstones. Figure 11 is an isopach map for the Dakota. The channelized character of the Dakota reservoir is apparent in the thickness maps. Trapping mechanisms include both stratigraphic and structural, as the channels drape over the structure.

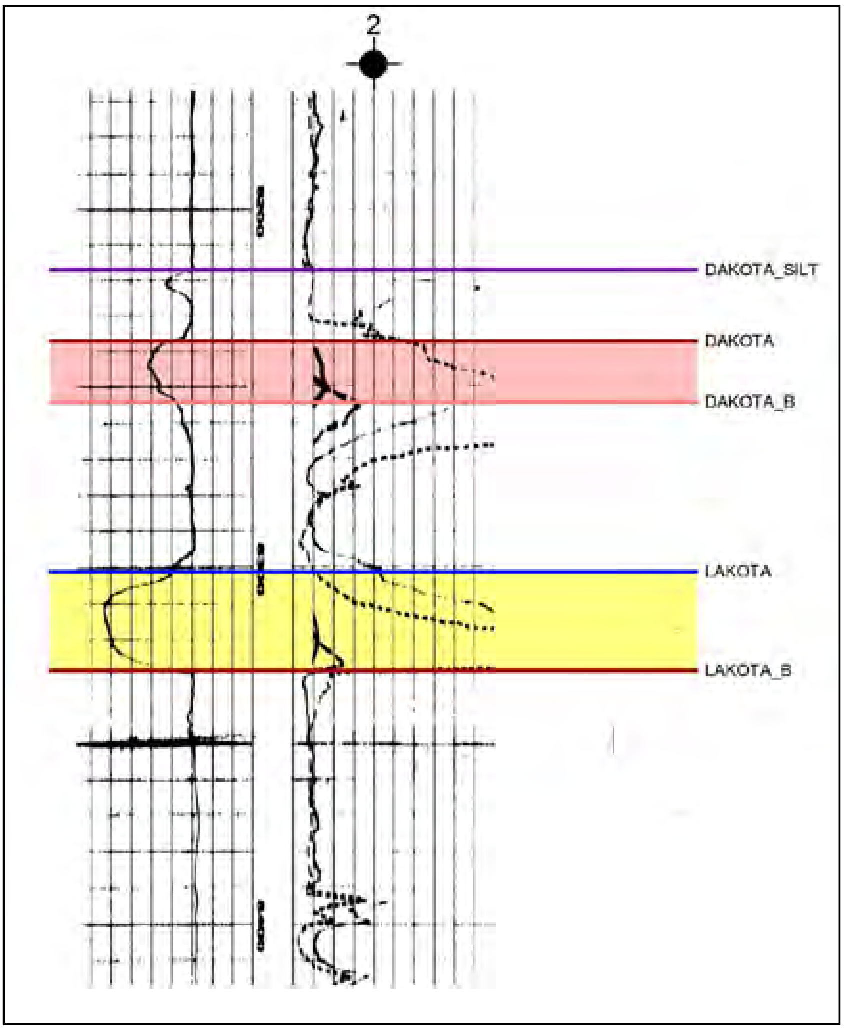

Figure 10: Type Log of Dakota and Lakota sandstones

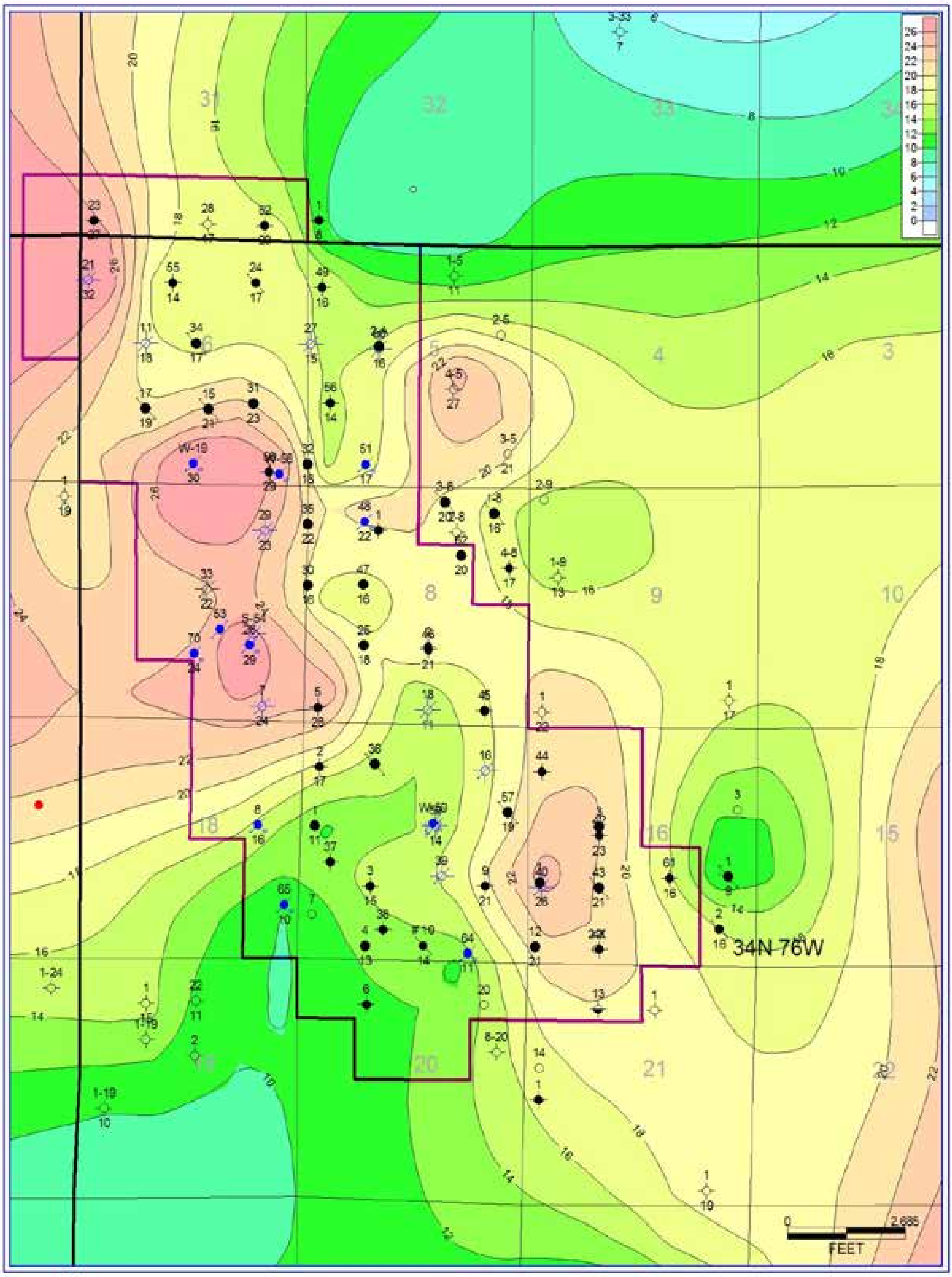

Figure 11 Isopach map of the Dakota formation in the South Cole Creek

3D Seismic

No 3D seismic data is known to exist within the area of Linc Energy's Glenrock assets.

CO_2 Flooding Overview

Linc Energy purchased the fields in Glenrock, Wyoming with the intention to continue the work to develop the assets for CO_2 flood development that Rancher Energy Corp. began. At the time the Glenrock fields begin to be developed for CO_2 flooding activities, the key stakeholders will be land, mineral and surface owners, the community of Glenrock, Wyoming, Linc Energy shareholders, and the State of Wyoming. Linc Energy plans to consider the needs of its stakeholders and ensure they are properly informed regarding the milestones of the project.

Between 2006 and 2007, Rancher Energy commissioned CO_2 reservoir modeling to be performed by a third party reservoir modeling firm, NITEC LLC. CO_2 reservoir modeling was performed for South Glenrock B Unit (Upper Muddy, Lower Muddy, and Dakota reservoirs) and Big Muddy (Frontier reservoir). The reports include detailed overviews of the field history, geology and production histories, as well as simulation predictions of oil production from CO_2 flooding scenarios. The scenarios assume a purchase rate of CO_2 of 40 MMSCF/D for each reservoir. Ryder Scott has reviewed copies of the final NITEC LLC reservoir simulation reports used in this economic report in their entirety, and find the reports to be a reasonable estimation of future oil production based on the available field data and the assumptions made.

Linc Energy has commenced facilities engineering and completed a pre-feasibility study of CO_2 pipeline routes. In addition, Linc Energy has entered into an agreement with Exxon-Mobil to provide CO_2 on an interruptible basis. Linc Energy is in discussions with several other CO_2 suppliers in anticipation of securing a CO_2 pipeline within the next 18 months before a final investment decision is made.

The project will consist of multiple phases of injecting CO_2 into new or existing injection wells while producing from new or existing producers. The full field development is still in its planning phase. The plan is ultimately dependent on timing the amount of available CO_2.

South Glenrock B Unit CO_2 Flooding

At the request of Linc Energy, Ryder Scott Company, L.P. has completed an economic study modeling the proposed CO_2 flood project of the Dakota formation and Upper & Lower Muddy formation in the South Glenrock Field. This model was constructed using input from the reservoir simulation study performed by NITEC LLC and cost estimates provided by Linc Energy. The South Glenrock Field is located primarily in T33-34N & R75-76W in Converse County, Wyoming. Economic modeling of the reservoir simulation results indicated that the CO_2 flood of the Dakota formation and Upper & Lower Muddy formation has an unrisked BFIT DNPV (10%) of 96.5 MM$ using a $61.48/bbl wellhead oil price. The DNPV (10%) reference date is June 30, 2015.

The annual volume schedules from the NITEC LLC reservoir study were provided to Ryder Scott Company and are displayed below in tables 1-3. NITEC LLC ran a full-field reservoir simulation of each formation independently using a series of inverted 9-spot patterns and assuming continuous miscible CO_2 injection. The minimum miscibility pressure for the Dakota oil is 2250 psi and the minimum miscibility pressure for the Upper & Lower Muddy formation is 2050 psi at reservoir conditions. Oil production begins once CO_2 injection begins. The resulting oil production stream is simulated for 23 years. The economic evaluation assumes a 6% exponential decline from year 24 until the economic limit is reached.

Oil volumes in this study were classified as "possible" under SPE-PRMS guidelines because of several factors: there is no current production in this field under CO_2 recovery and no pilot has been implemented to prove the process. These factors are weighted against the successful Salt Creek CO_2 flood analogy and the significant amount of historical reservoir descriptive information available from past primary and secondary recovery operations in the South Glenrock Field.

YEAR	Oil Prod MSTB	Gas Prod MMSCF	Water Prod MSTB	Gas Inj MMSCF	CO2 Purch. MMSCF
2006	792	7,998	4006	22,560	14,562
2007	3232	27,897	2012	40,859	12,962
2008	3746	29,393	394	40,025	10,632
2009	2605	29,200	154	35,928	6,728
2010	1665	29,200	242	33,432	4,232
2011	987	29,200	318	32,030	2,830
2012	605	29,280	233	31,048	1,768
2013	427	29,200	187	30,572	1,372
2014	396	29,200	171	30,493	1,293
2015	385	29,200	163	30,426	1,226
2016	378	29,280	151	30,462	1,182
2017	369	29,200	142	30,337	1,137
2018	364	29,200	132	30,298	1,098
2019	366	29,200	124	30,271	1,071
2020	368	29,280	116	30,332	1,052
2021	371	29,200	109	30,229	1,029
2022	369	29,200	100	30,214	1,014
2023	373	29,200	94	30,180	980
2024	380	29,280	89	30,244	964
2025	380	29,200	84	30,138	938
2026	379	29,200	79	30,128	928
2027	382	29,200	75	30,105	905
2028	387	29,280	71	30,172	892

Table 1 NITEC LLC Base Case Prediction – Dakota

YEAR	Oil Prod MSTB	Gas Prod MMSCF	Water Prod MSTB	Gas Inj MMSCF	CO2 Purch. MMSCF
2006	406	13,702	1952	20,356	7,254
2007	517	22,802	544	25,264	2,462
2008	426	24,719	265	26,294	1,575
2009	333	25,215	181	26,381	1,166
2010	283	25,395	142	26,353	958
2011	261	25,144	120	26,012	868
2012	245	25,442	106	26,210	768
2013	237	25,461	95	26,177	716
2014	233	25,509	85	26,184	675
2015	231	25,545	78	26,184	639
2016	233	25,626	72	26,265	639
2017	233	25,736	66	26,356	620
2018	232	25,683	61	26,297	614
2019	225	25,584	58	26,150	566
2020	219	25,704	54	26,286	582
2021	215	25,734	51	26,270	536
2022	214	25,724	49	26,246	522
2023	209	25,722	46	26,233	511
2024	209	25,780	43	26,286	506
2025	212	25,665	42	26,172	507
2026	212	25,646	39	26,140	494
2027	209	25,650	37	26,140	490
2028	210	25,698	36	26,186	488

Table 2 NITEC LLC Base Case Prediction - Upper Muddy

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YEAR	Oil Prod MSTB	Gas Prod MMSCF	Water Prod MSTB	Gas Inj MMSCF	CO2 Purch. MMSCF
2006	1690	22,955	1655	32,315	9,360
2007	968	29,587	84	32,191	2,604
2008	511	29,431	50	30,885	1,454
2009	393	29,174	40	30,270	1,096
2010	318	29,285	36	30,133	848
2011	322	29,331	34	30,151	820
2012	276	29,326	32	30,042	716
2013	241	29,293	31	29,920	627
2014	232	29,241	29	29,847	606
2015	230	29,234	29	29,829	595
2016	239	29,303	29	29,930	627
2017	245	29,200	28	29,817	617
2018	238	29,200	27	29,784	584
2019	233	29,200	25	29,766	566
2020	230	29,280	25	29,833	553
2021	227	29,200	24	29,740	540
2022	224	29,200	23	29,732	532
2023	217	29,200	23	29,749	549
2024	217	29,280	21	29,784	504
2025	216	29,200	21	29,694	494
2026	214	29,200	20	29,683	483
2027	213	29,200	20	29,672	472
2028	214	29,280	19	29,748	468

Table 3 NITEC LLC Base Case Prediction - Lower Muddy

A summary of the gross capital development costs and proposed schedule for the South Glenrock B Unit CO_2 flood are outlined below (Total gross cost $372.25 MM), which was provided by Linc Energy:

2016 Capital Costs- $126.5 MM (1/2 of total costs of central facility and pipeline split between South Glenrock B Unit and Big Muddy)

Tank Battery with Compression-$37.5 MM
Pipeline- $26.5 MM
Power- $17.5 MM
60 Wells @ $750M/well- $45 MM

2017 Capital Costs- $48.5 MM

61 Wells @ $750M/well- $45.75 MM
11 Wells converted to injection @ $250 M/well- $2.75 MM
Dakota CO_2 injection and Production begins 1/1/2017

2018 Capital Costs- $9.75 MM

9 Wells @ $750M/well- $6.750 MM
12 Wells converted to injection @ $250 M/well- $3.00 MM

2019 Capital Costs- $161 MM

Additional Compression and Power for UM and LM- $100 MM
70 Wells @ $750M/well- $52.5 MM
11 Wells converted to injection @ $250 M/well- $2.75 MM

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23 Well workovers for completion of UM and LM reservoirs @ $250 M/well- $5.75 MM
UM and LM CO_2 injection and Production begins 1/1/2019

2020 Capital Costs- $8.75 MM

12 Wells converted to injection @ $250 M/well- $3.00 MM
23 Well workovers for completion of UM and LM reservoirs @ $250 M/well- $5.75 MM

2021 Capital Costs- $8.5 MM

12 Wells converted to injection @ $250 M/well- $3.00 MM
22 Well workovers for completion of UM and LM reservoirs @ $250 M/well- $5.50 MM

2022 Capital Costs- $ 9.25 MM

15 Wells converted to injection @ $250 M/well- $3.75 MM
22 Well workovers for completion of UM and LM reservoirs @ $250 M/well- $5.5 MM

The initial field development is assumed to begin in 2016 however the production from the Dakota field is modeled to begin January 1, 2017. The production for the Upper & Lower Muddy formation is modeled to begin January 1, 2019.

Big Muddy Field CO_2 Flooding

At the request of Linc Energy, Ryder Scott Company, L.P. has completed an economic study modeling the proposed CO_2 flood project of the Wall Creek formation in the Big Muddy Field. This model was constructed using input from the reservoir simulation study performed by NITEC LLC and cost estimates provided by Linc Energy. The Big Muddy Field is located primarily in T33N R76W in Converse County, Wyoming. Economic modeling of the reservoir simulation results indicated that the CO_2 flood of the Wall Creek formation has an unrisked BFIT DNPV (10%) of 326.3 MM$ using a $61.48/bbl wellhead oil price. The DNPV (10%) reference date is June 30, 2015.

The annual volume schedules from the NITEC LLC reservoir study were provided to Ryder Scott Company and are displayed below in table 4. NITEC LLC ran a full-field reservoir simulation of the Wall Creek formation using a series of inverted 9-spot patterns and assuming continuous miscible CO_2 injection. The minimum miscibility pressure for the Wall Creek oil is 1600 psia. Oil production begins once CO_2 injection begins. The resulting oil production stream is simulated for 20 years.

Oil volumes in this study were classified as “possible” under SPE-PRMS guidelines because of several factors: there is no current production in this field under CO_2 recovery and no pilot has been implemented to prove the process. These factors are weighted against the successful Salt Creek CO_2 flood analogy and the significant amount of historical reservoir descriptive information available from past primary and secondary recovery operations in the Big Muddy Field.

YEAR	Water Prod MSTB	Oil Prod MSTB	Gas Prod MMSCF	Water Inj MSTB	Gas Inj MMSCF	CO2Purch. MMSCF
	ANNUAL VOLUMES					
1	0	0	0	7294	0	0
2	9272	3136	22226	7073	36797	14571
3	6509	4189	29201	6897	43800	14599
4	5875	3638	29277	6622	43920	14643
5	5473	2968	29200	5303	43800	14600
6	1069	32[illegible]1	29174	602	43760	14586
7	80	3321	29227	0	43780	14553
8	47	3089	29280	0	38326	9046
9	39	2785	29200	0	36274	7074
10	40	25[illegible]8	29200	0	35353	6153
11	43	23[illegible]2	29200	0	34857	5657
12	45	2193	29280	0	34443	5163
13	45	2081	29200	0	33964	4764
14	44	19[illegible]2	29200	0	33672	4472
15	44	1860	29200	0	33439	4239
16	43	1787	29280	0	33346	4066
17	44	1726	29200	0	33073	3873
18	43	1646	29200	0	32861	3661
19	40	1559	29200	0	32618	3418
20	40	1483	29280	0	32497	3217

Table 4 NITEC LLC Base Case Prediction – Wall Creek

A summary of gross the capital development costs and proposed schedule for the Big Muddy CO_2 flood are outlined below (Total gross cost $317.25 MM), which was provided by Linc Energy:

<u>2016 Capital Costs- $166 MM (1/2 of total costs of central facility and pipeline split between South Glenrock B Unit and Big Muddy)</u>

Tank Battery with Compression-$37.5 MM
Pipeline- $26.5 MM
Power- $17.5 MM
Additional Compression and Power for Frontier- $50 MM
46 Wells @ $750M/well- $34.5 MM

<u>2017 Capital Costs- $37 MM</u>

46 Wells @ $750M/well- $34.5 MM
10 Wells converted to injection @ $250 M/well- $2.5 MM
BM CO_2 injection and Production begins 1/1/2015

<u>2018 Capital Costs- $37.25 MM</u>

46 Wells @ $750M/well- $34.5 MM
11 Wells converted to injection @ $250 M/well- $2.75 MM

<u>2019 Capital Costs- $37 MM</u>

46 Wells @ $750M/well- $34.5 MM
10 Wells converted to injection @ $250 M/well- $2.5 MM

<u>2020 Capital Costs- $37.25 MM</u>

46 Wells @ $750M/well- $34.5 MM
11 Wells converted to injection @ $250 M/well- $2.75 MM

2021 Capital Costs- $2.75 MM

11 Wells converted to injection @ $250 M/well- $2.75 MM

The initial field development is assumed to begin in 2016 however the production from the Big Muddy field is modeled to begin January 1, 2017.

CO_2 Economic Assumptions

With the economic model complete, economics were run to determine the value of the CO_2 flood of the Dakota formation and Upper & Lower Muddy formation in the South Glenrock Field and the Wall Creek formation in the Big Muddy Field. Linc Energy requested that Ryder Scott Company run economics using the following working interests and net revenue interests for the CO_2 flood report:

South Glenrock B Unit WI=94.132542%
South Glenrock B Unit Net Revenue Interest = 73%

Big Muddy Working Interest = 100%
Big Muddy Net Revenue Interest = 76.681818%

A severance tax rate of 6.00% and an ad valorem tax rate of 6.66% were deducted from cash flows. An oil price of $61.48/bbl was provided by the client to be used for the base case. As all gas production will be reinjected, there will be no gas revenues. Operating costs were assumed to be $6500/well/month. CO_2 was assumed to cost $2.25/mcf. Oil prices, CO_2 costs, and operating costs were held constant over the life of the project. Development costs for the project were unescalated from the current levels.

Reserves Included in This Report

The proved and possible reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report. The proved developed non-producing reserves included herein consist of the shut-in category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved, probable and possible gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Linc Energy's request, this report addresses the proved and possible reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered." Probable reserves are "those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." Possible reserves are "those additional reserves which are less certain to be recovered than probable reserves" and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserve categories that are included herein have not been adjusted to reflect these varying degrees of risk associated with them and thus are not comparable.

Reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved and possible reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Linc Energy's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved, probable and possible reserves actually recovered and amounts of proved, probable and possible income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which Linc Energy owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved and possible reserves for the properties included herein were estimated by performance methods, reservoir simulation or analogy. One hundred percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include decline curve analysis, which utilized extrapolations of historical production data available through June 2015 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Linc Energy or obtained from public data sources and were considered sufficient for the purpose thereof.

One hundred percent of the possible undeveloped reserves included herein were estimated by using reservoir simulation results of each proposed enhance recovery project.

To estimate economically recoverable proved and possible oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved, probable and possible reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Linc Energy has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved and possible production and income, we have relied upon data furnished by Linc Energy with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, ad valorem and production taxes, development costs, development plans, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Linc Energy. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

For the purposes of this report, Ryder Scott did not visit the Linc Energy field in Converse County, Wyoming. It was the opinion of Ryder Scott that a field visit would not materially affect the evaluation.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved, probable and possible reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved, probable and possible reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Linc Energy. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Linc Energy furnished us with the above mentioned average prices in effect on June 30, 2015. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the- month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by Linc Energy. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Linc Energy to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserve category for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Proved Realized Prices	Average Possible Realized Prices
North America		Enterprise Onshore Crude Oil Bulletin			
United States	Oil/Condensate	Wyoming Sweet	$59.13/Bbl	$61.48/Bbl	$61.48/Bbl

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by Linc Energy and are based on the operating expense reports of Linc Energy and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Linc Energy. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Linc Energy and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. Linc Energy's estimates of zero abandonment costs after salvage value for onshore properties were used in this report. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Linc's estimate.

The possible undeveloped reserves in this report have been incorporated herein in accordance with Linc Energy's plans to develop these reserves as of June 30, 2015. The implementation of Linc Energy's development plans as presented to us and incorporated herein is subject to the approval process adopted by Linc Energy's management. As the result of our inquiries during the course of preparing this report, Linc Energy has informed us that the development activities included herein have been subjected to and received the internal approvals required by Linc Energy's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Linc Energy. Additionally, Linc Energy has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of June 30, 2015, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Linc Energy were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Linc Energy. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations.

We have provided Linc Energy with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

James L. Baird

James L. Baird, P.E.
Colorado License No. 41521
Managing Senior Vice President

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company L.P. James Larry Baird was the primary technical person responsible for overseeing the estimate of the reserves.

Mr. Baird, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President and also serves as Manager of the Denver office, responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Baird served in a number of engineering positions with Gulf Oil Corporation (1970-73), Northern Natural Gas (1973-75) and Questar Exploration & Production (1975-2006). For more information regarding Mr. Baird's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Baird earned a Bachelor of Science degree in Petroleum Engineering from the University of Missouri at Rolla in 1970 and is a registered Professional Engineer in the States of Colorado and Utah. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Colorado and Utah Board of Professional Engineers recommend continuing education annually, including at least one hour in the area of professional ethics, which Mr. Baird fulfills. As part of his 2011 continuing education hours, Mr. Baird attended an internally presented sixteen hours of formalized training as well as an eight hour public forum. Mr. Baird attended RSC Reserves Conferences and various professional society presentations specifically on the new SEC regulations relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Baird attended an additional sixteen hours of formalized in-house and external training during 2013 and 2014 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, reserve reconciliation processes, overviews of the various productive basins of North America, evaluations of resource play reserves, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 45 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Baird has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits.

These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

Probable reserves. *Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.*

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

POSSIBLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(17) defines possible oil and gas reserves as follows:

Possible reserves. *Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.*

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate, but which have not started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

LINC ENERGY LTD

(the "Company")

Independent Qualified Person's Declaration and Consent Statement

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DECLARATION

I, James L. Baird, confirm that in relation to the enclosed qualified person's report on Linc Energy Petroleum (Wyoming), Inc. dated July 30, 2015 (the "**Report**"):

- I am an independent qualified person ("**Independent Qualified Person**") in accordance with the requirements of the listing manual ("**Listing Manual**") of Singapore Exchange Securities Trading Limited (the "**SGX-ST**"). In particular, I confirm that I have satisfied the requirements of Rule 210(9)(b) of the Listing Manual as follows:

  (a) I am not a sole practitioner;
  (b) I am a partner of Ryder Scott Company, L.P. in relation to the production of the Report;
  (c) I am personally, and Ryder Scott Company, L.P.'s partners, directors, substantial shareholders and their associates are, independent of the Company, its directors and substantial shareholders, its advisers and their associates;
  (d) I, as well as Ryder Scott Company, L.P.'s partners, directors, substantial shareholders and their associates, do not have any interest, direct or indirect, in the Company, its subsidiaries or associated companies and will not receive any benefits, direct or indirect, other than remuneration paid in connection with the Report; and
  (e) the remuneration paid to me or Ryder Scott Company, L.P. in connection with the Report is not dependent on the attainment of any stipulated results or findings of the Report; and

- in preparing the Report, I took into account all relevant information supplied to me by the directors of the Company.

CONSENT STATEMENT

I, named as the Independent Qualified Person, hereby consent to the inclusion of all references to my name in the form and context in which they appear in the Report, the Declaration and this Consent Statement, and the submission of the same to the SGX-ST and/or release by the Company on SGXNET.

James L. Baird

Signature of Independent Qualified Person

July 30, 2015

Date

Colorado Licensed Professional Engineer

Professional Society Affiliations and Membership
(insert organisation name)

License Number 41521

Membership Number

Margaret Hugo

Signature of Witness

MARGARET HUGO, AURORA, CO

Print Witness Name and Residence (eg. Town/Suburb)

Glossary of Terms

Acronym	Definition
3D	Three Dimensional
ASX	Australian Securities Exchange
BOPD / BPD / BOE / BBOE	Barrels of Oil Per Day / Barrels Per Day / Barrels of Oil Equivalent / Billion Barrels of Oil Equivalent
CO_2	Carbon Dioxide
DEHP	Department of Environment and Heritage Protection (Queensland, Australia)
GTL	Gas to Liquids
HI	Hydrogen Indices
JORC	Joint Ore Reserves Committee
MMBLS / MMBOE	Million Barrels of Oil / Million Barrels of Oil Equivalent
MCF	Million Cubic Feet
MDL	Mining Development License
MIGD	Moving Injection Gravity Drainage
MOU	Memorandum of Understanding
MW	Mega Watt
OOIP	Original Oil in Place
OTCQX	USA Securities Exchange
PEL	Petroleum Exploration License
PFL	Petroleum Facility License
PI	Production Indices
PV	Present Value
QPR	Qualified Person Report
RBC	Royal Bank of Canada
RO	Vitrinite Reflectance
R&D	Research and Development
SGX	Singapore Exchange
TOC	Total Organic Carbon
UCG	Underground Coal Gasification