AUSTRALIAN
SMALL-CAP INVESTIGATOR
Special Report

Interview with MEO Australia Ltd CEO Jürgen Hendrich

By Kris Sayce
Editor, Australian Small Cap Investigator

Kris Sayce (Australian Small Cap Investigator): How do you see the future for the LNG industry in Australia and globally?

Jürgen Hendrich (CEO, MEO Australia Ltd): MEO sees a strong future for the global LNG industry with Australia playing a major role. LNG is forecast to grow at 7% per annum until 2020, with the bulk of this growth on the Pacific Rim. In our view, this projected growth rate can't be matched by new capacity unless all announced plants come on line. Globally, there have only been four new projects sanctioned in the past four years, one of which is Woodside's Pluto project. Based on this record, it's difficult to believe that all or even a major proportion of the proposed Australian plants will be in production by 2020. On that basis, we see the global LNG market remaining robust, with low operating cost plants thriving.

KS: How long do you think it will be before MEO is producing revenues from its projects?

JH: The gas processing projects take approximately 3 years to build from the time a Final Investment Decision (FID) is made. The rate limiting step at the moment is confirmation of a suitable gas supply – this requires further appraisal drilling and reserves certification for most of the undeveloped gas fields in the Timor Sea. Once gas is secured, the projects will require full Front End Engineering and Design (FEED) work ahead of achieving FID and securing funding. We expect the first methanol or LNG could be produced by early 2015.

KS: Do you have a timeframe for MEO to become profitable? And what profit levels/margins do you anticipate?

JH: The economics for MEO's gas processing projects are very robust and we expect their operating costs to fall into the lowest cost quartile. As such, we expect to be profitable once these large scale projects come on stream. However, the levels of profitability will clearly depend on an amalgam of input variables including commodity prices, level of project debt, depreciation allowances, MEO's equity in the projects, etc. As a guide to the scale of these projects, the TSMP is expected to generate between US$500 and US$750 million of revenues annually, and the TSLNGP between US$1 & US$1.5 billion.

KS: Does MEO have sufficient cash to finance its projects or will it require additional capital raisings/ borrowings? If not, where will MEO source additional financing from?

JH: MEO plans to secure one or more partners to complete appraisal drilling of its gas discoveries. These parties will also be expected to fund the majority of FEED studies and other costs ahead of FID. At that point, project finance for up to 70% of the capital expenditure will likely be sought, with MEO and its partners required to fund approximately the remaining 30% from cash reserves and/or new equity raisings.

KS: What is the breakeven gas/oil prices? And what impact does that have on the viability of MEO's projects?

JH: If we assume the breakeven level provides debt coverage and a 10% return on equity, the likely oil price for a methanol or LNG project to achieve this performance is ~US$30/bbl or approximately US$175/tonne methanol price.

KS: MEO is proposing a unique way of handling high CO_2 gas. Can you tell me more about it?

JH: Most companies have a singular focus on monetising gas resources – i.e. conversion to LNG for export markets. This is perfectly fine for high quality gas, rich in contained natural gas liquids and low in CO_2. The trouble is, this type of gas quality is rare in offshore Australia and where this type of gas quality is present, it has generally been developed. Most of Australia's undeveloped gas resources however, have lower levels of natural gas liquids and higher levels of CO_2. Invariably, these two parameters are inversely related, i.e. increasing levels of CO_2 generally correspond to lower levels of natural gas liquids. Both factors negatively impact project economics. Throw in deep water and long distances from infrastructure and you can basically appreciate why so few Australian LNG projects have managed to achieve FID and why the larger companies find the idea of converting Coal Seam Gas (CSG) in Queensland to LNG so attractive.

Where CO_2 is present in the input gas stream, the accepted solution is geo-sequestration of CO_2. This involves separation of the CO_2 from the input gas stream and re-injection into deep geological formations. The proposed Gorgon LNG project is planning to sequester 80% of the CO_2 in its input gas stream – which contains approximately 10% CO_2 – within formations deep underneath Barrow Island.

This is one approach to dealing with CO_2 and involves substantial investment in additional capital with ongoing operating costs to separate the CO_2 and pump it back underground. The higher the CO_2 in the input gas stream, the more expensive it is to remove and sequester.

When MEO and Shell drilled Evans Shoal-2 in the Timor Sea in 1998 and confirmed a substantial gas resource containing ~25% CO_2, it was obvious to MEO that within the context of LNG projects needing to compete globally, this level of CO_2 was always going to compromise the economics of conversion to LNG and therefore sought to find a better economic solution that ***benefitted*** from this level of CO_2. MEO discovered that the Steam Methane Reforming (SMR) process for syngas production created a surplus of hydrogen atoms and gas containing 22-25% CO_2. This essentially balances the surplus hydrogen and created more methanol for the same sized reformer compared with converting pure natural gas without CO_2. The CO_2 could therefore be converted into a revenue stream thereby transforming the economics!

While the chemistry was elegant, the development economics for a methanol project were still compromised by the remoteness (several hundred km's) of the Evans Shoal gas field from Darwin. The project could not sustain the cost of a long distance pipeline to shore.

KS: What was the solution?

JH: Well, a study of the bathymetric maps in the vicinity of the gas field, revealed several natural geological features – Shoals – that could potentially be used to host gas processing infrastructure. Tassie Shoal was selected as the preferred Shoal on the basis of its low levels of biodiversity and so the Tassie Shoal Methanol Project (TSMP) was born. Environmental approvals for the TSMP were granted in 2002 and extended in 2004 to include a 3 Mtpa LNG project.

The combination of the proximity of Tassie Shoal to several undeveloped high CO_2 gas fields, sequestration of CO_2 into methanol derivatives and the ability to prefabricate the entire gas processing plants in low cost South East Asian construction yards offers the potential to transform the economics of the region. By providing a gas processing hub in close proximity to the gas resources it will lower the economic threshold for development for each gas discovery.

KS: MEO isn't the only company proposing LNG facilities in the Timor Sea. How are some of these other projects progressing?

JH: There is only one operating LNG plant in the region – ConocoPhilips' Darwin LNG plant. The 3.7 Mtpa plant is fed by the super liquids rich gas from the Bayu-Undan field, some 550km away. The contained natural gas liquids effectively under wrote the development of the LNG project. It has approval for a second train, but cannot secure additional high quality gas in the region, despite investing several hundred million dollars on exploration.

The Woodside operated Greater Sunrise gas fields are a similar distance from Darwin. The gas has attractive, albeit more modest levels of associated natural gas liquids than Bayu-Undan with around 4% CO_2. Project development is complicated by geo-political differences in relation to whether gas processing facilities should be hosted in Timor-Leste, Darwin or on floating facilities.

Inpex's Abadi discovery has around 8-9% CO_2 and lies in predominantly Indonesian waters, across the international maritime boundary with Australia. Inpex has chosen to pursue a Floating LNG option due to the remoteness of this discovery.

Beyond these projects, the other discoveries include Barossa, Caldita, Evans Shoal, Heron, Blackwood and Chudditch. All of these discoveries contain upwards of 10% CO_2.

Inpex and Total are partners in the Ichthys gas discovery in the Browse Basin and have proposed to pipe this gas (8-14% CO_2) some 880 km to Darwin for processing, underscoring the remoteness of the Browse Basin.

KS: Apart from the TSMP, what – if anything – sets MEO apart from these other projects?

JH: MEO's proposed gas processing hub on Tassie Shoal is the only project that provides a solution to the distance and/or CO_2 challenges these projects face. Our proposed plants have the unique benefits of using proven, off the shelf technology, combining these in a low cost labour environment and shipping the completed plants to site for immediate installation and commissioning. By locating the plants in the heart of the gas province, the need for expensive (and typically uneconomic) pipelines, the economic threshold for development is lowered for all of the undeveloped gas fields in the region. This has enormous economic benefits for all resource custodians and ultimately all Australians.

Good investing,

Kris Sayce
Editor, *Australian Small Cap Investigator,* and *Money Morning Australia*

To visit the Money Morning Australia website click here.

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