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merlin COAL PTY LTD ABN 81 134 469 471

ordiv PETROLEUM PTY LTD ABN 29 111 102 697

frontier OIL & GAS PTY LTD ABN 91 103 194 136

helium AUSTRALIA PTY LTD ABN 11 078 104 006

merlin WEST PTY LTD ABN 59 114 346 968

central GREEN PTY LTD ABN 84 128 245 876

central GEOTHERMAL PTY LTD ABN 86 128 245 885

central PETROLEUM SERVICES PTY LTD ABN 57 140 628 155

ASX ANNOUNCEMENT & PRESS RELEASE **ASX CODE: CTP**

1 September 2011

TO: The Manager, Company Announcements ASX Limited

CONTACT: John Heugh +61 8 9474 1444

INDEPENDENT UNCONVENTIONAL VALUATION

Central Petroleum Limited (ASX:CTP) ("Central" or the "Company") has pleasure in releasing an interim independent valuation of the Company's unconventional gas and oil resources by Mulready Consulting Pty Ltd with contributions by Holt Campbell and Payton Pty Ltd and DSWPET Pty Ltd. The valuation report is attached to this announcement.

The preferred valuation for the upstream component (exploration and potential production) of the fully risked prospective resources in Central's acreage in the Amadeus and Southern Georgina Basins is $412 million while the preferred valuation for the proposed downstream component (ultra-clean transport fuel production from Fischer Tropsch GTL plant) is $5 billion, should gas discoveries prove sufficient to supply the 5TCF of gas which would be required. 59 TCFG and 6.1 Bn.bbls prospective resources at "mean" level have been estimated by independents DSWPET Pty Ltd in previously announced reports in the Central's Amadeus and Southern Georgina Basin unconventional acreage

These valuations are based on very early stage exploration generally in Australia for unconventional petroleum and will warrant re-visiting as more transactional, exploration and possible production data become progressively available.

"Interest in Australian unconventional acreage and recent farmin deals into unconventional acreage have escalated considerably which has been confirmed with the BG Group's farmin to Drillsearch's Cooper Basin acreage imputing a valuation of approximately $300/net acre" said Central's Managing Director Mr Heugh today. "It is noteable that the Drillsearch farmout to the BG Group was a much smaller acreage but a much richer deal than previous unconventional farmout deals in Australia which collectively have imputed values ranging from approximately $10 to $35/net acre. Clearly, if further exploration brings success, the implied valuation of farmout deals per net acre of promising Australian unconventional acreage may gravitate closer to the far more lucrative North American valuations."

In order to maximise shareholder value, Central aims, inter alia, to selectively and progressively farmout portions of its vast acreage to different companies on successively better terms as exploration success in and around the Company's acreage progresses. Both Rodinia and Petrofrontier have current drilling programmes in areas close to Central which may de-risk the Company's acreage should those companies have exploration success. The Company does not wish to enter in to early broadacre deals over all or most of its acreage with the one company

Drilling Update

The Company is planning contingently to re-enter the Surprise-ST1 well late September 2011 to accelerate a programme over the next 6-12 months focussed on re-entry and testing of Surprise-ST1 (10 MMbbls UOIIP-P50) for oil potential in both conventional and unconventional horizons. Significant oil shows were encountered in several horizons in December 2010 and based on porosity and permeability measurements, a 9m cored section with abundant oil shows was reported by RPS Energy to be capable of flowing between c.500-1,000 bbls/day subject to sufficient oil saturation.

Access road and drill pad maintenance and upgrading is well advanced and a contract with ADS Rig 6 is being finalised.

Central is planning to test both the conventional and unconventional potential of the Surprise structure. The Surprise prospect has geological parallels to the geology of the Mereenie field, which is believed on discovery had over 300 MMbbls of oil in place of which less than 10% has been extracted to date, the hydrocarbon column being dominated by tight sands, siltstones and shales with minor intervals of highly permeable sandstones with prolific production rates.

Other wells planned before the year's end incude the drilling of Mt Kitty-1, a large condensate/helium/gas prospect (UGIIP 2 TCFG, 100 BCF helium-P50) and the drilling of Madigan-1, the first well on a giant structure in the Pedirka Basin thought to have UOIIP potential of over 4 billion barrels (P50) based on preliminary mapping of new seismic acquired in 2010.

John Heugh

Managing Director
Central Petroleum Limited

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NOTICE: The participating interests of the relevant parties in the respective permits and permit applications which may be applicable to this announcement are:

- *EP-82 (excluding the Central subsidiary Helium Australia Pty Ltd ("HEA") and Oil & Gas Exploration Limited ("OGE") (previously He Nuclear Ltd) Magee Prospect Block) - HEA 100%*
- *Magee Prospect Block, portion of EP 82 – HEA 84.66% and OGE 15.34%.*
- *EP-93, EP-105, EP-106, EP-107, EPA-92, EPA-129, EPA 130, EPA-131, EPA-132, EPA-133, EPA-137, EPA-147, EPA-149, EPA-152, EPA-160, ATP-909, ATP-911, ATP-912 and PELA-77 - Central subsidiary Merlin Energy Pty Ltd 100% ("MEE").*
- *The Simpson, Bejah, Dune and Pellinor Prospect Block portions within EP-97 – MEE 80% and Rawson Resources Ltd 20%.*
- *EP-125 (excluding the Central subsidiary Ordiv Petroleum Pty Ltd ("ORP") and OGE Mt Kitty Prospect Block) and EPA-124 – ORP 100%.*
- *Mt Kitty Prospect Block, portion of EP 125 - ORP 75.41% and OGE 24.59%.*
- *EP-112, EP-115, EP-118, EPA-111 and EPA-120 - Central subsidiary Frontier Oil & Gas Pty Ltd 100%.*
- *PEPA 18/08-9, PEPA 17/08-9 and PEPA 16/08-9 - Central subsidiary Merlin West Pty Ltd 100%.*

General Disclaimer and explanation of terms:
Potential volumetrics of gas or oil may be categorised as Undiscovered Gas or Oil Initially In Place (UGIIP or UOIIP) or Prospective Recoverable Oil or Gas in accordance with AAPG/SPE guidelines. Since oil via Gas to Liquids Processes (GTL) volumetrics may be derived from gas estimates the corresponding categorisation applies. Unless otherwise annotated any potential oil, gas or helium UGIIP or UOIIP figures are at "high" estimate in accordance with the guidelines of the Society of Petroleum Engineers (SPE) as preferred by the ASX Limited but the ASX Limited takes no responsibility for such quoted figures.
As new information comes to hand from data processing and new drilling and seismic information, preliminary results may be modified. Resources estimates, assessments of exploration results and other opinions expressed by CTP in this announcement or report have not been reviewed by relevant Joint Venture partners. Therefore those resource estimates, assessments of exploration results and opinions represent the views of Central only. Exploration programmes which may be referred to in this announcement or report have not been necessarily been approved by relevant Joint Venture partners and accordingly constitute a proposal only unless and until approved. All exploration is subject to contingent factors including but not limited to weather, availability of crews and equipment, funding, access rights and joint venture relationships.

Media Release
1 September 2011

Five billion dollar estimate for central Australian oil and gas resources.

Two new reports on the unconventional oil and gas resources in Central Petroleum's vast Northern Territory acreage have estimated their value as high as $5 billion dollars.

The higher estimate, by Perth's Holt Campbell Payton consultancy, also identified a Darwin-based gas to liquid plant as an attractive option.

A second report, by geologist David Warner of DSWPET, suggested a value of $412 million based on transactions in unconventional acreage to date in Australia and anticipated fully risked EMV values- but added that this valuation will need to be re-visited as more exploration is done for unconventionals in central Australian basins.

DSWPET forsees a pipeline-delivered cost, in Darwin, of $5.50 per thousand cubic feet for gas based on a fully risked 5 TCFG and 250 million barrels of oil recoverable based on fully risked gas and oil prospective resources.

A recurring factor in both reports is the fact that the unconventional petroleum sector is virtually unknown in Australia, whereas in North America it has become a major factor in the continent's fuel supplies.

Recent success by Beach Oil in the Cooper Basin has encouraged confidence however in the potential success of unconventional fuels as a major factor in future oil and gas supplies for Australia's needs, and as valuable long-term export commodities.

Central Petroleum CEO John Heugh, in releasing the reports, pointed to the benefits indicated in the report: Australia's government is acutely aware that oil and gas are currently costing the country a $16 billion deficit in the import/export equation, which will double by 2015 unless more is done, quickly, to exploit more home-grown fuel.

As an added bonus, the gas to liquid process uses most of its available carbon, leaving a very small carbon footprint, so there is a double benefit of low pollution and a low potential carbon tax cost in the future, he concluded.

Full reports are attached.

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VALUATION OF

CENTRAL PETROLEUM LIMITED'S

AMADEUS BASIN

AND

SOUTHERN GEORGINA BASIN

UNCONVENTIONAL RESOURCES

August 2011

VALUATION CTP UNCONVENTIONAL RESOURCES

The suggested value of CTP's Unconventional Oil and Gas Resources is based on two separate Reports

David Warner of DSWPET[1] valued the recoverable estimated potential resource[1] of gas by assuming that gas would be sold at $5.50 via a gas pipeline to Darwin, with a sale of 5TCF (8% risked) of the estimated 59 TCF mean prospective resource he had estimated in two separate reports for Central Petroleum earlier in 2011[2 and 3.]
The DSWPET report also considered the additional value of the Southern Georgina Basin potential oil resource. Thus for the purposes of valuing the upstream unconventional resources of Central, the Amadeus Basin was considered to contain an unconventional prospective gas resource, whilst the Georgina Basin was regarded as containing a prospective unconventional oil resource.
A risked (4%) potential recoverable resource of 240 million barrels of oil was calculated, and a value estimated assuming this was marketed via pipeline to Darwin.
David Holt of Holt Campbell Payton Pty Ltd ("HCP") in a separate report[4] estimated the value which would be added to the risked 5 TCF gas stream by establishing a 50,000 bpd GTL plant located in Darwin, drawing down the 5TCF of gas over 30 years.

The results may be summarised as follows:

Report	Range of Values	Suggested Value
DSWP Commercial Transactions Method (Oil & Gas)		A$124 million
DSWP EMV method (Oil & Gas)		A$1.04 billion
DSWP Overall Value best estimate (Oil & Gas)		A$412 million
HCP	A$ 2-10 billion*	A$5 billion**

- HCP consider a range of NPVs with debt ratios ranging from zero to 60% and a range of discount rates of between 10% and 15%.
- ** NPV mid point range assuming 60% debt funding at 8%pa and 40% equity funding by Central, with a discount rate of 12%

COMMENTS
DWSP's report valuing the upstream oil and gas potential of Central's unconventional acreage utilised both the recent commercial transactions method, and EMV method ("Expected Monetary Value"), the latter based on his estimated size of the potential undiscovered resource. The Report states that

1. The commercial transactions method is constrained by the limited number of transactions within Australia c.f. the mature state of the industry in the USA.
2. The EMV's calculated must be treated with due caution, as the underlying assumptions are yet to be proved in an Australian context, whilst any estimate of future gas prices incorporates its own risk.

HCP's Report also has built in assumptions regarding financing costs, product costs over time, construction costs and operating costs.
None-the-less they consider that a GTL plant located in Darwin is a viable and attractive option provided the gas supply can be guaranteed.

Whilst the reports are 'stand alone' the overall results may be summarised as follows

1. Prospective gas resources with a mean estimate of 59 TCF can be recognised within specified play areas of the Amadeus and Southern Georgina Basins. David Warner arbitrarily risks these at 8% for a risked resource of approximately 5TCF, with a calculated mean EMV value of $563 million, assuming gas is sold at $4/mcf and piped to Darwin at a cost of $1.50/mcf.
2. Mean prospective oil resources of 6.1 billion barrels are recognised in Central's unconventional Southern Georgina Basin with a risked (4%) prospective resource of 240 million barrels. Assuming this is marketed via pipeline to Darwin, Warner quotes a mean EMV based valuation of $480 million.
3. Warner also estimates Central's overall unconventional oil and gas holdings at a mean value of $124 million based on recent commercial transactions.
4. If the risked prospective resource volume of 5TCF of gas can be delivered to Darwin over 30 years at an initial price ($5.50/mcf), HCP's review suggests that a GTL plant utilising the latest technology would prove a robust investment (IRR>12%) that would find a ready market within Australia, providing premium petroleum products.
5. These conclusions are qualified by the fact that no commercial development of unconventional resources has been undertaken in Australia as yet, although exploration drilling of an unconventional target has recently commenced in the Southern Georgina Basin, and Beach Petroleum are reporting success in their Nappamerri trough (Cooper Basin) program, reporting 2TCF of contingent (2C) reserves, based on recent vertically fracced wells.
6. The HCP report estimates the value that a GTL plant would add to the gas as between $2 billion to $10 billion, emphasising the enormous potential that could follow discovery and development of a major gas resource. At this early stage of unconventional gas exploration within Australia and more specifically within CTP's extensive Amadeus and Georgina acreage we must await the future results of upcoming exploration if these conclusions are to be confirmed.
7. It is also likely that a major partner capable of providing specialised technical expertise and 'financial muscle' would be required to bring the GTL project to fruition, but this scenario has not been specifically addressed in the above reports.

Conclusion

The unconventional oil and gas potential within CTP's acreage has a log normal mean risked estimated value of $412 million assuming sale by pipeline to Darwin.

If a substantial set of preconditions were met, value adding as a result of gas sales to a GTL plant could be very attractive, and capable of adding of order $5 billion to the value of the gas (60% debt share at 8%pa, $NPV_{12\%}$)

Such values are based on a number of key assumptions which may or may not eventuate, but which nevertheless provide a range of potential outcomes for exploration and development of Central's extensive Permit and Application areas in Central Australia.The valuations are based on the presumption that the subject permits are all granted.

References:

1.DSWPET for Central Petroleum Limited, August 2011
Unconventional Resource Valuation
*2.*DSWPET for Central Petroleum Limited, January 2011
Unconventional Resource Evaluation Assessment for the Lower Larapinta Formation, Amadeus Basin.
3.DSWPET for Central Petroleum Limited, April 2011

Unconventional Resources Assessment, The Arthur Creek Formation, Georgina Basin Australia
4. HCP Pty Ltd for Central Petroleum Limited, August 2011
Appraisal of Value Added by GTL for Potential Non-Conventional Gas Resources

INDEPENDENCE
Mulready Consulting Services Pty Ltd is not operating under an Australian financial services licence in providing this report.

Neither Mulready Consulting Services Pty Ltd nor any of its directors or employees has any beneficial interest in Central Petroleum Limited, nor in the pending permits which are the subject of this valuation, nor in any adjacent permits.

Mulready Consulting Services prepared the Independent Geologist's Report for Central Petroleum Limited's 2005 Prospectus.
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that might reasonably be expected to be or have been capable of influencing Mulready Consulting Services Pty Ltd in providing this Report.
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DATE OF REPORT
This report was prepared in August 2011, and is dated August 23rd 2011

QUALIFICATIONS
Jack N. Mulready graduated from the University of Melbourne with a B.Sc. (Geology) 1963, Dip. Ed.(1966) and B.A. (History)1999 and from R.M.I.T. with a Fellowship Diploma in Management in 1978. He has over 36 years of experience within the petroleum exploration and production industry in Australia, New Zealand, USA, Indonesia, China and PNG.
He is a member of the Petroleum Exploration Society of Australia, the Geological Society of Australia and the American Association of Petroleum Geologists (Certified APPG Geologist No. 5321), and has prepared numerous independent geologist's reports and valuations for a variety of Australian companies in accordance with the requirements of the Australian Stock Exchange.

Jack Mulready
Principal, Mulready Consulting Services Pty Ltd
B.Sc., B.A., Dip. Ed., F.Dip. RMIT,
MGSA, MPESA, Certified AAPG Geologist #5321.

Central Petroleum Limited

Unconventional Resource Valuation

BY

DSWPET
August 2011

This report was prepared for the exclusive use and sole benefit of Central Petroleum Limited. and may not be used for any other purpose without prior written consent from DSWPET. DSWPET reserves the right to revise any opinions provided herein if any relevant data was not made available or if any data provided was found to be erroneous. Neither confirmation of title nor confirmation of percentage ownership was included in the brief.

The Directors

Central Petroleum Limited

Suite 3,Level 4, Southshore Centre

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South Perth

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Dear Sir

Please find the attached valuation of the unconventional resource plays within Central Petroleum Limited's acreage in the Amadeus and Southern Georgina Basins, Central Australia.

The following are the plays identified in the Cambro-Ordovician of the Amadeus Basin

1. Horn Valley Siltstone Continuous Gas Play
2. Horn Valley Siltstone Continuous Oil Play
3. Pacoota Sandstone Continuous Gas Play
4. Stairway Sandstone Continuous Gas Play

The following are the plays identified in the Cambrian of the Southern Georgina Basin

1. The Lower Arthur Creek Shale Continuous Gas Play
2. The Lower Arthur Creek Shale Continuous Oil Play
3. The Upper Arthur Creek Continuous Gas Play

The areal extent of these plays is 33,725 KM^2 or 8.33 million acres and the total technically recoverable prospective resource is 6 Billion BBLS of Oil and 59 TCF of Gas.

Given the large degree of uncertainty in technical and commercial outcomes of this play type, two evaluation methods were used. The methods used were the current transaction method and the expected monetary value method. Neither method on its own was deemed satisfactory for obtaining a value. However the range of value was seen as indicative and the mean of the range was used as the valuation.

The acreage is currently valued at A$412Million

Given the immaturity of the exploration and development of these plays in Australia it is expected that the value of these assets can change dramatically over time as more information regarding their viability is at hand. It is expected that if the planned programme for 2012 in the Amadeus and or the Petrofrontier programme in the Georgina is successful a significant upgrade in valuation will be required.

Yours Sincerely

David Warner
DSWPET Pty Ltd
BSc Hon, MSc DIC.

1 Summary

Central Petroleum Limited (Central) has an extensive acreage position in Central Australia in 4 basins, the Southern Georgina, the Pedirka, the Amadeus and the Wiso. To date, Central has identified a total of 7 new unconventional gas and oil resource plays with a combined mean prospective resource of 6.1 bill BBLS Oil and 59 TCF Gas. They can be described as high risk, frontier basin plays, in most cases remote from existing infrastructure and relatively unexplored. Given its location and its likely geology, it is possible that further unconventional plays will be discovered in the Lander Trough, Wiso Basin.

The purpose of this report is to value the acreage in terms of the identified unconventional plays operated by Central in the Southern Georgina and Amadeus Basins.

Central has accumulated a significant contiguous area in Central Australia at 100% ownership in a mix of sole right applications and granted permits. The strategic nature of this acreage position with respect to (a) the presence of identified possible unconventional plays which have commercial analogs in the USA and (b) firm upcoming exploration and appraisal programmes in similar and or adjacent acreage that will test several of these unconventional plays, should be noted with regard to the valuation of its acreage.

The possibility exists that the Central could establish a large gas and or oil resource play and apply appropriate completion techniques required to commercially produce them. In this case the value could increase by as much as an order of magnitude.

Conversely, although seismic, drill logs, cuttings and core samples are available to assess unconventional potential in the subject areas, at this stage no real exploration for these plays has been attempted and therefore currently there is considerable risk to a successful outcome and considerable uncertainty in the commerciality of the successful outcome should it happen. It is noted that an unconventional exploration drilling programme has recently been commenced in adjacent acreage to Central’s Southern Georgina Plays. The outcome of this programme could affect the risk, uncertainty and value attributed to those plays considerably.

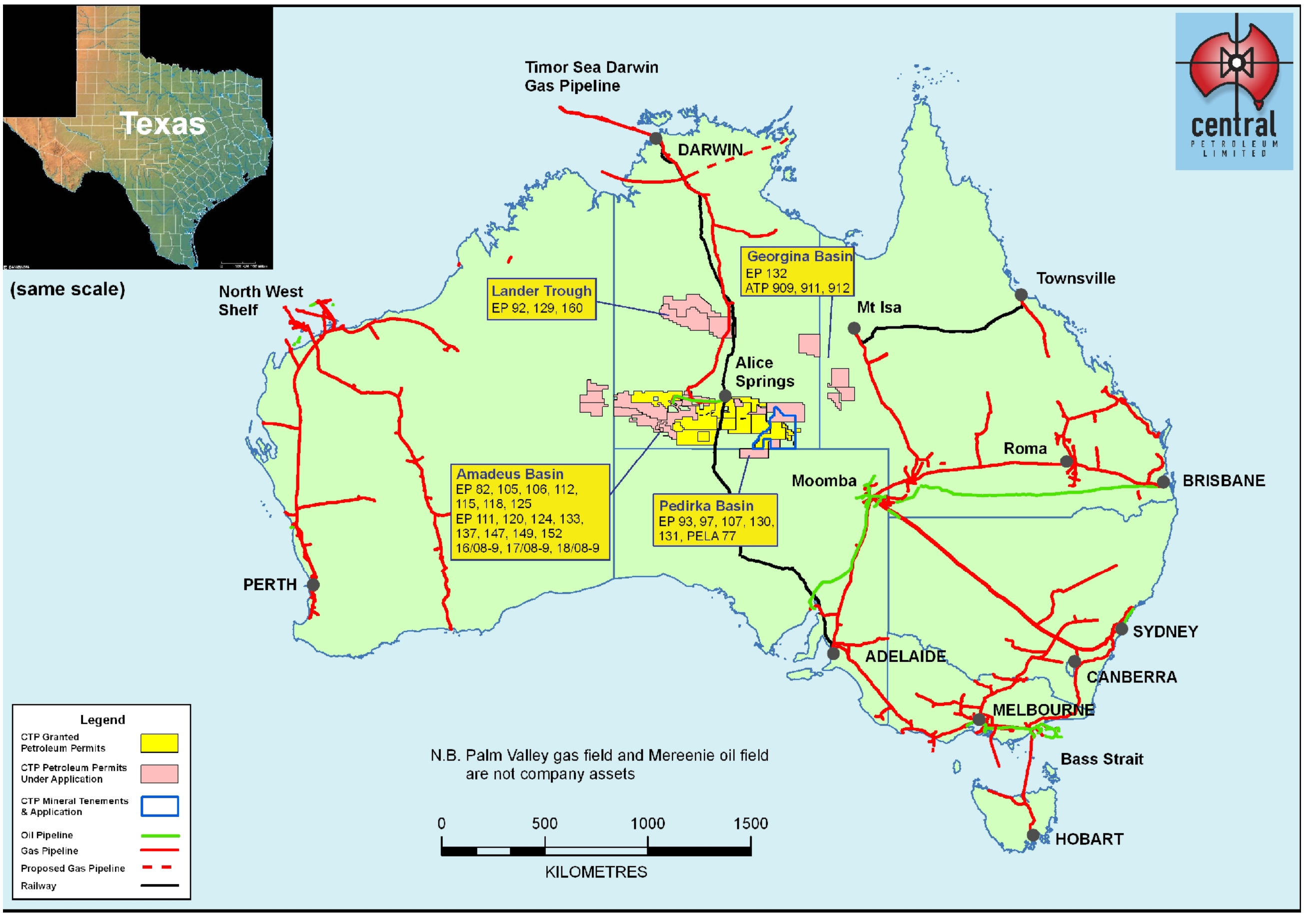
The scarce information available on these play types in Australia means there is considerable uncertainty in using any valuation methodology. Two methods were used, Commercial Transactions and Expected Monetary Value, to arrive at a range of values which reflected that uncertainty. Details of the methodologies used are included in sections 3 and 4 and the assumptions made for each methodology are included in sections 10 and 11. Neither method is considered capable of estimating the current value of Central's unconventional plays on its own.

A valuation has been made by assuming that:

1. the results from the methodologies used represent the value distribution
2. the distribution is log normal and
3. the mean of that distribution represents the best estimate of value

The range of value for the unconventional plays in the Central Petroleum Limited acreage is between A$124 (P99) and $1,043 million(P1). The Mean for this distribution and thus the valuation for the Unconventional Plays identified in the Central Petroleum's Acreage is A$412 million.

2 Discussion



The plays and their mean prospective resources are:

1. Georgina Basin (NT-EPA 312 and QLD-ATP 909,911 and 912P)
    - Upper Arthur Creek Shale Gas - 15 TCF (4.531 KM^2)
    - Lower Arthur Creek Shale Gas - 18 TCF (4,068 KM^2)
    - Lower Arthur Creek Shale Oil - 5 Billion BBLS (14,747 KM^2)
2. Amadeus Basin (NT- EP 82,111,112,115,120,124,137)
    - Stairway Tight Gas - 5.1 TCF (3,440 KM^2)
    - Pacoota Tight Gas - 9.8 TCF (3,440 KM^2)
    - Horn Valley Shale Gas - 11.3 TCF (7,395 .KM^2)
    - Horn Valley Shale Oil - 1.1 Billion BBLS (7,031 KM^2)

Until recently the presence of unconventional continuous gas and oil accumulations in tight reservoirs has not been recognized in the Australian oil and gas industry. In North America the presence of these accumulations, which are outside conventional structural closure and in reservoirs with very low permeability, is now proven beyond doubt as has their commercial significance. Examples are the Barnett Shale and Bakken Shale with technically recoverable resources of 50 TCF gas and 4 Billion BBLS oil respectively. The value of these unconventional hydrocarbon accumulations is reflected in the billions of dollars being spent by the majors such as Shell, BP, BHP Billiton and Exxon-Mobil to acquire parts of these new plays.

A review of the recent transactions in the US for Unconventional Plays indicates these plays are valued at between $2,000 US to $30,000 US per Acre. A review of recent Australian Unconventional Acreage deals estimate acreage values ranging from A$87 to $4 per acre.

The 1,000 fold difference in value for unconventional acreage between Australia and the USA is due to:

1. the immaturity of the Australian unconventional plays
2. their limited access to infrastructure and markets
3. their limited access to appropriate drilling and completion equipment

Realistically, because of the above the current value of Australian plays has to be significantly less than their USA counterparts, however, the comparison does give an indication of the potential for unconventional acreage value growth in the Australian Plays, should exploration and more importantly appraisal be successful.

Therefore it was considered necessary and prudent to reflect the uncertainty associated with valuation of unconventional plays in Australia by using two evaluation techniques to describe the range of values which might be ascribed to the Central Petroleum's unconventional plays.

3 The Commercial Transaction Method

Transactions selected were recent commercial transactions in Australian frontier acreage with similar unconventional plays. The transactions used in the analysis included:

1. The Hess Corporation farmin to the Falcon Oil and Gas acreage in the Beetaloo Basin
2. The Beach farmin to the Adelaide Energy acreage in the Nappamerri Trough Cooper Basin
3. The Mitsubishi farmin to the Buru acreage in the Canning Basin
4. The PetroFrontier farmin to the Texalta acreage in the Georgina Basin
5. The Conoco Philips farmin to New Standard acreage in the Canning Basin
6. The QGC farmin to the Drillsearch acreage in the Nappamerri Trough, Cooper Basin

The actual per acre value of the unconventional plays recently purchased is difficult to establish unambiguously in any of the transactions studied, as all the deals have included some conventional prospects and the value put on these by the purchasing parties is not public knowledge. However, it has been possible to estimate a Base Case unconventional play valuation, in a frontier basin because in one of the above cases the resource estimates for all conventional and unconventional plays was publically available. To establish a base case value for unconventional acreage in Australia, the value of the conventional and unconventional acreage was deemed to be proportional to their respective risked resource estimates.

The base case is the Beetaloo Basin, where the transaction between Hess Corporation and Falcon Oil and Gas took place in February 2011. In this deal Hess Corporation bought 62.5% of the Basin (3.92 million acres net) for total estimated expenditure commitments of A$112 million. Based on the proportion of the risked unconventional resource (89%), the base case valuation for the unconventional plays in the Beetaloo Basin is estimated at A$27 per acre.

Similar frontier basin acreage deals which included both conventional and unconventional potential in the Canning, Georgina and Cooper Basins cost A$17,A$87 and A$4/acre respectively. If it is assumed that the conventional plays are of little value in these areas, a very likely outcome given the results of past exploration, these estimates support the quantum of the base case valuation.

Once the base case unconventional acreage value was established a model was created to rate the relative value of unconventional acreage in each of the deals investigated and the Central acreage. The relative value of the unconventional acreage was based on three factors.

1. The *Maturity* of the play concept model
2. The *Production potential*
3. The *Location* of the play regards existing infrastructure

Each unconventional asset was rated against each other for each of these factors by allocating a value of 1.0 to the best acreage in each factor thence rating the other areas by comparison between 0.1 and 0.9. A relative value factor for unconventional play acreage in each basin was then calculated by combining the value of the 3 factors by multiplication and the value /acre by multiplying the relative value factor and the base case valuation of A$27/acre.

The most recent transaction in July 2011 is the QGC farmin to the Qld. Nappamerri Trough portion of the Cooper Basin. In this transaction the base value of the Nappamerri Trough unconventional has increased approximately 2 time from the 2009 Beach farmin. This reflects the positive from the recent positive results from the Holdfast and encounter wells. However these results in the Permian Cooper Basin do not significantly alter the value for the Cambro - Ordovician Central Georgina and Amadeus Unconventional plays as they have different source material (terrestrial verses marine) and a significantly different age and structural complexity. As in the US no one shale play is a blue print for other shale plays.

Transaction Method Valuation

This methodology arrives at a value for the unconventional acreage of A$11/acre or A$52 mill for Central's Southern Georgina Basin and A$20/acre or A$72 mill for the Amadeus Basin.

Thus the valuation for the Central Petroleum Unconventional assets using the modified Transaction Methodology is $124 million.

This method of valuation is subject to a large degree of uncertainty as there is no way of knowing how much value was placed on the conventional plays in the deals studied. Also the method does not include an appreciation of the strategic value or size of Central's excellent acreage position with respect to the 7 identified unconventional resource plays.

4 EMV Methodology

The play potential of the Central Basin acreage contains both oil (6 bill BBLS) and gas (59 TCF). These are substantial prospective resources thus both need to be addressed in the valuation. It was decided to arbitrarily assign 1 discovery of each to each basin with the risked resource as the pool size. As the Georgina Basin has greater oil potential the oil discovery was assigned to that basin. Therefore the Amadeus was assigned the gas discovery.

The assumptions used in the cash flow models are included in Appendix 3 and 4. The development and product treatment and transport to processing facility (upstream) scenarios used were those that appeared to be the most likely given the current technologies available, availability of infrastructure in the area and taxation regime. It is recognized that these scenarios may change considerably with time.

Oil Prospective Resource Valuation (6.1 Billion BBL)

The likely size of the oil development was arbitrarily judged to be 240 million BBLS, equivalent to 4% of the mean prospective resource estimate of 6.1 Billion BBLS. The value of this development was estimated by use of a full cycle cash flow model specifically built for a Central Australian Development of 240 million BBLS under the best guess RRT regime. The model showed that the NPV/BBL outcome was most sensitive to the price of oil , the production function and the discount rate. Assuming a flat price oil at A$90(real) a number of models that represented the uncertainty range were constructed resulting in a NPV/BOE distribution of A$-1.69 (P90) to A$4.04 (P10). EMV's for each of the scenarios were calculated as follows:

EMV = (Risked reserve *Value/BBL) - risked Exploration and Appraisal cost

This resulted in a range of EMVs from A$-499mill (P90) to A$899 mill(P10) with a mean of A$480 million.

Gas Prospective Resource Valuation (59 TCF)

The likely size of the gas development was arbitrarily judged to be 5 TCF or 8% of the prospective resource estimate of 59 TCF. The value of this development was estimated by use of a full cycle cash flow model specifically built for a Central Australian Development of 5 TCF under the best guess RRT regime. The model did not include a gas processing facility but did envisage it would be either a GTL or LNG facility or both. The model showed that the NPV/BBL outcome was most sensitive to gas price, the production function and the discount rate. Assuming a constant gas price of A$5.50/GJ delivered to the facility a number of scenarios that represented the uncertainty range were constructed resulting in a NPV/BOE distribution of A$-0.12 (P90) and A$1.33 (P10).

EMV's for each of the above scenarios were calculated as follows:

EMV = (Risked reserve *Value/BBL) - risked Exploration and Appraisal cost

This resulted in a range of EMVs from A$-208mill (P90) to A$933 mill(P10) with a mean of A$563 million.

EMV Method Valuation

The sum of the mean dollar value estimates of the oil and gas risked resources is considered to be the mean EMV value of the Acreage.

Thus the acreage value according to the EMV modelling = A$ 480 + 563Million. = A$1.04 billion.

These EMV valuations are subject to a high degree of uncertainty which is associated with the immaturity of the unconventional plays. These plays are often described as technology plays because the greatest risk is not finding the hydrocarbons but the commercial application of new drilling and completion technologies. The combination of horizontal drilling and multistage fracs used so successfully in the USA is yet to be trialled in Australia. Furthermore, the successful combination of technologies used in the USA may not be the technologies that needed for the Australian conditions. Whilst there are commercial developments of similar unconventional oil and gas plays in the US , currently there are none in Australia.

Given the high degree of uncertainty associated with a new play and with no production analogues in Australia the EMV methodology should only be used as an indicator of value.

5 Valuation

The big difference, i.e.A$124 vs A$1.04 Billion, in the valuation of the unconventional acreage between the two methods used, is understandable as it reflects the immaturity of these play types in Australia and resulting lack of reliable information on many of the critical inputs for both methodologies used.

Whilst these unconventional plays are currently considered high risk, based on the success of these play types in the USA, the possibility exists that Central can establish a large gas and or oil resource play and find the completion techniques required to commercially produce them.

It is concluded that neither the Transaction Method value nor the EMV Methodology value, on their own, represent fair market value for the unconventional assets of Central Petroleum Limited

A valuation has been made by treating the calculated values as representing the high (P1) and low (P99) values in a lognormal distribution with the derived Mean being the best estimate.

On this basis a value of A$412 million is estimated for the identified unconventional plays in the Central Petroleum Limited's Amadeus and Georgina acreage.

This valuation is limited to the extent of the identified unconventional plays in Central Petroleum's Permits in the Southern Georgina and Amadeus Basins and does not attribute any value to other plays which may occur within Central Petroleum's acreage.

6 Risks to Valuation

The risks apparent to any evaluation of the current value of unconventional resources in Australia are very high given the lack of exploration and development information under Australian geological conditions. It is important to note that no commercial unconventional hydrocarbons have been discovered yet in any of Central's acreage or adjacent to it.

The biggest risk involved in unconventional resource plays is often not the presence of hydrocarbons but whether it is technically and commercially viable to produce. As there is no production data for any of the plays the uncertainty in the production function used in any cash flow model is very high at this time.

It should be noted that this valuation relies on a very limited data set due to the immaturity of the exploration and development of unconventional shale and tight gas plays in Australia. With this in mind it is expected that current valuations may change considerably either up or down as results from expenditure on these plays are at hand.

7 Declarations

7.1 Competence of Author

DSWPET Pty Ltd is an independent consultant company with one professional employee David Warner.

David Warner is a geologist with 38 years in the oil and gas industry working in various roles related to drilling, operations, well site evaluation, appraisal and development planning and play generation and evaluation.

David has a BSc Geology with Honours from Armidale University and an MSc from Imperial College London. Currently he is a member of both AAPG and SPE.

Between 2000 and 2009 David worked as team leader of the Santos Unconventional Reservoir Group developing new unconventional plays, evaluation procedures and completion techniques in the Cooper Basin. In this programme he lead significant experiments ranging from shear stimulation of tight sandstone reservoirs to fracture stimulation of deep coals. He has worked with many of the technical leaders in unconventional reservoirs from North America and has travelled widely throughout that area. During his time at Santos he did resource estimates on several large Santos unconventional assets, including coal, shale and tight sandstone reservoirs, which were endorsed by leading consultants for unconventional reservoirs in the US.

In 2008 he served on the organizing and technical committee for the SPE Workshop on Unconventional Reservoirs held in the Barossa Valley. In 2010, in conjunction with Petroleum Consultants MBA/AWT, he (DSWPET Pty Ltd) published a Shale Gas Atlas for Australia.

7.2 Independence of Author

Neither DSWPET Pty Ltd nor any of its directors or employees has any beneficial interest in Central Petroleum Limited, nor in the pending permits which are the subject of this valuation, nor in any adjacent permits.

There are:

(a) no other interests, whether pecuniary or not and whether direct or indirect, of DSWPET Pty Ltd or any associate of DSWPET Pty Ltd;

(b) no other associations or relationships between DSWPET Pty Ltd or any associate of DSWPET Pty Ltd

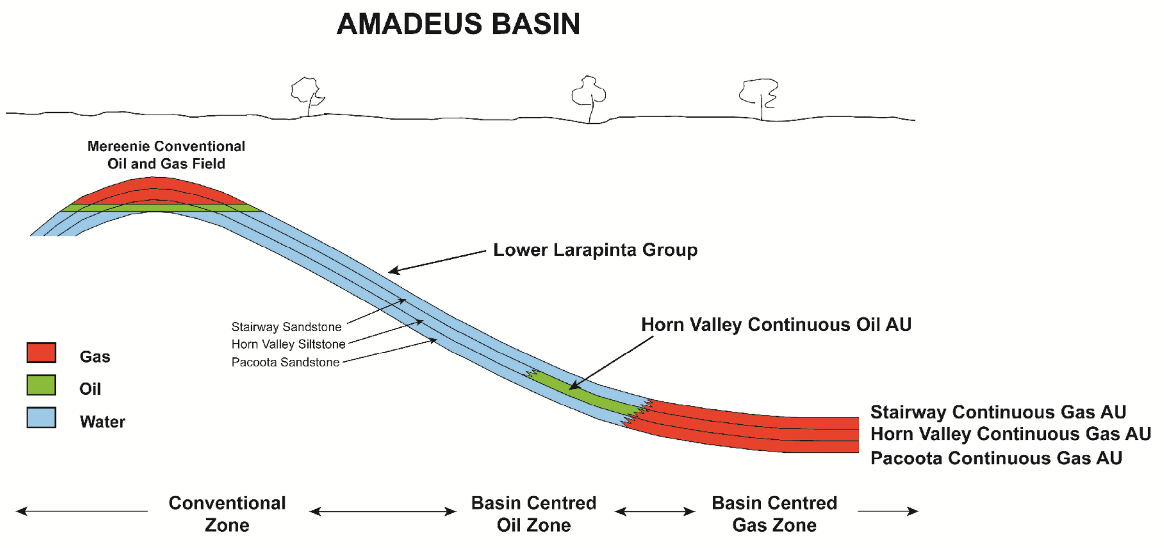
and Central Petroleum Limited that might reasonably be expected to be or have been capable of influencing DSWPET Pty Ltd in providing this Report.

8 Appendix 1 - Amadeus Unconventional Plays

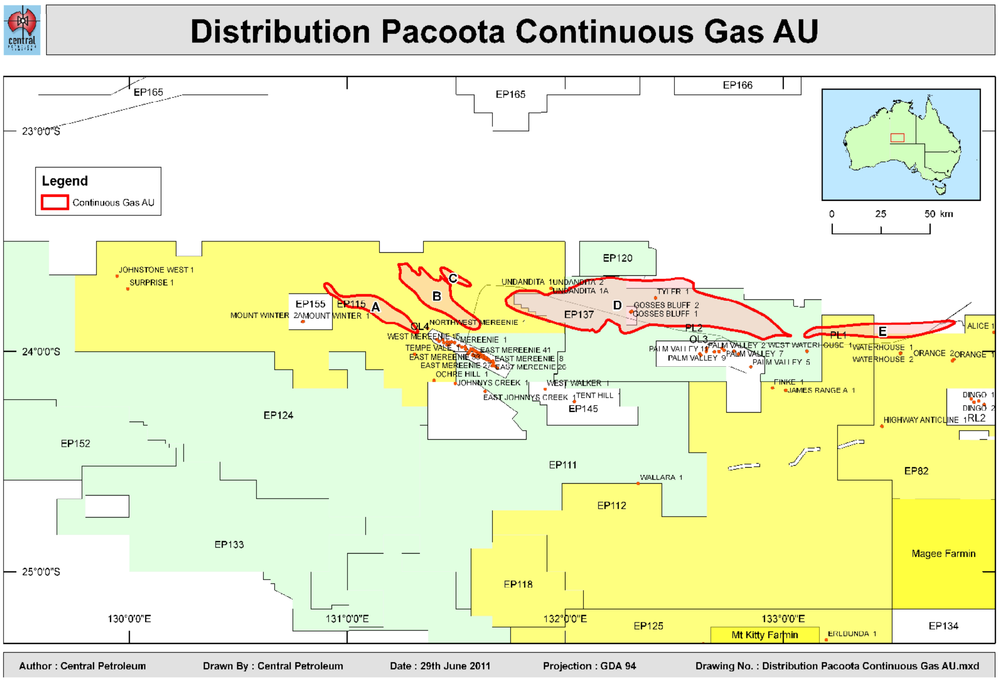
Unconventional Assessment Units

For the Lower Larapinta TPS in the Amadeus Basin the following unconventional assessment units (AUs) or Plays are proposed:

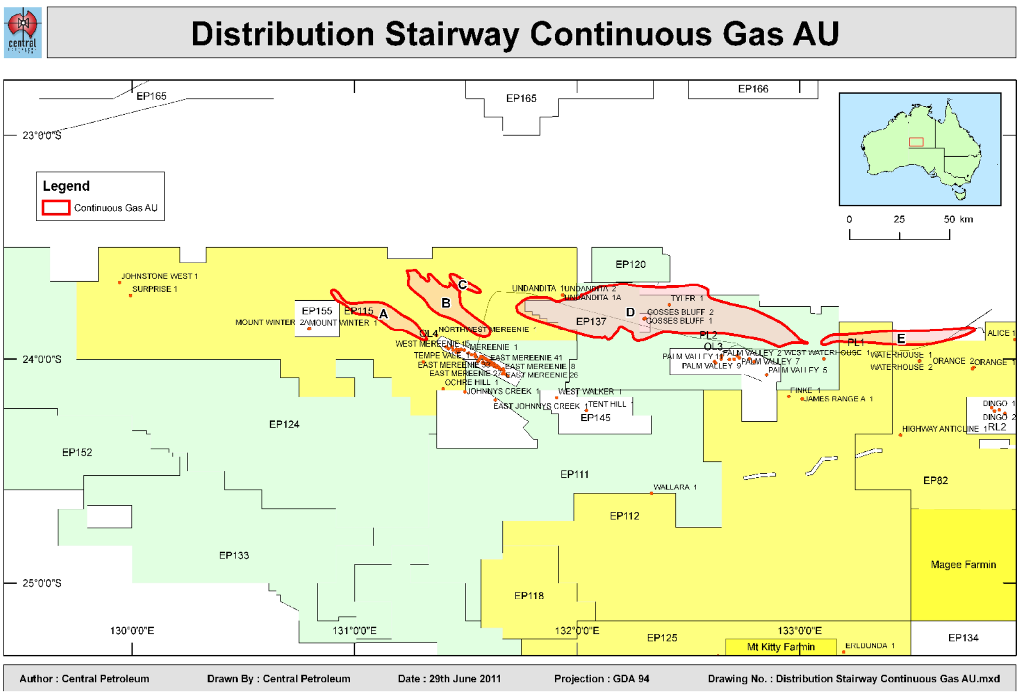
1. Horn Valley continuous oil AU
2. Horn Valley continuous gas AU
3. Stairway continuous gas AU
4. Pacoota continuous gas AU



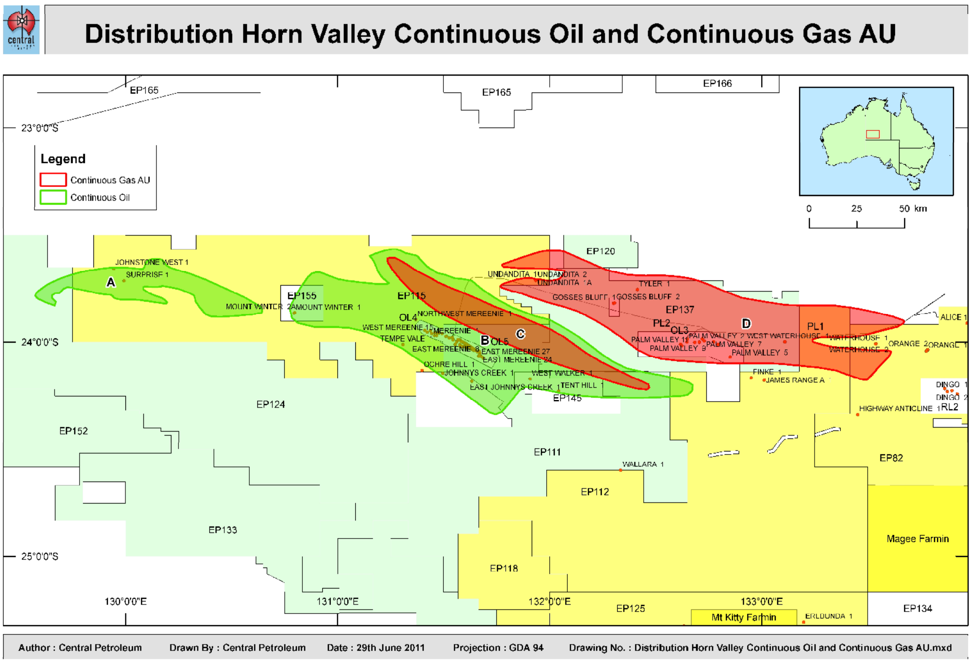
Diagramatic Cross Section showing Unconventional Assessment Units (AUs) of the Lower Larapinta TPS



Distribution Pacoota Continuous Gas AU.



Distribution Stairway Continuous Gas AU



Distribution Horn Valley Continuous Oil and Continuous Gas AU's

Technically Recoverable Resources

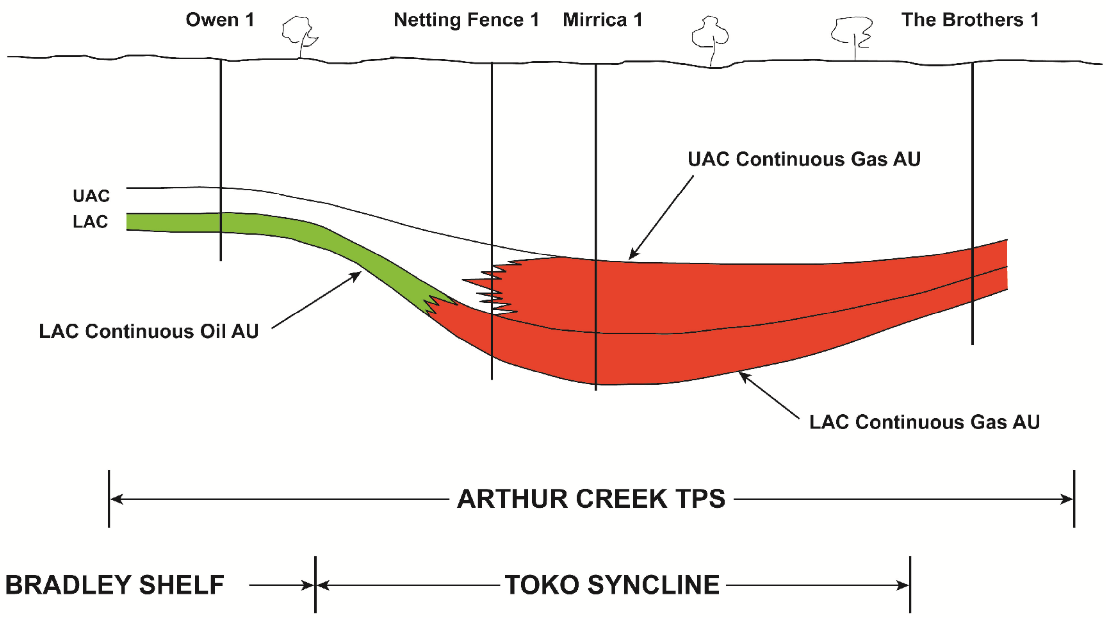
Assessment Unit	Prospect Recoverable Resource (TCF or Billion BBLS)			
	P90	P50	P10	Mean
Stairway Sandstone Continuous Gas AU	1.1	3.4	10.5	5.1
Pacoota Sandstone Continuous Gas AU	2.4	7.0	19.7	9.8
Horn Valley Continuous Gas AU	2.6	7.7	23.8	11.3
TOTAL GAS				25.9 TCF
Horn Valley Continuous Oil AU	0.207	0.77	2.5	1.14
Total Oil				1.1 Billion BBLS

Amadeus Basin Central Petroleum Prospective Resources

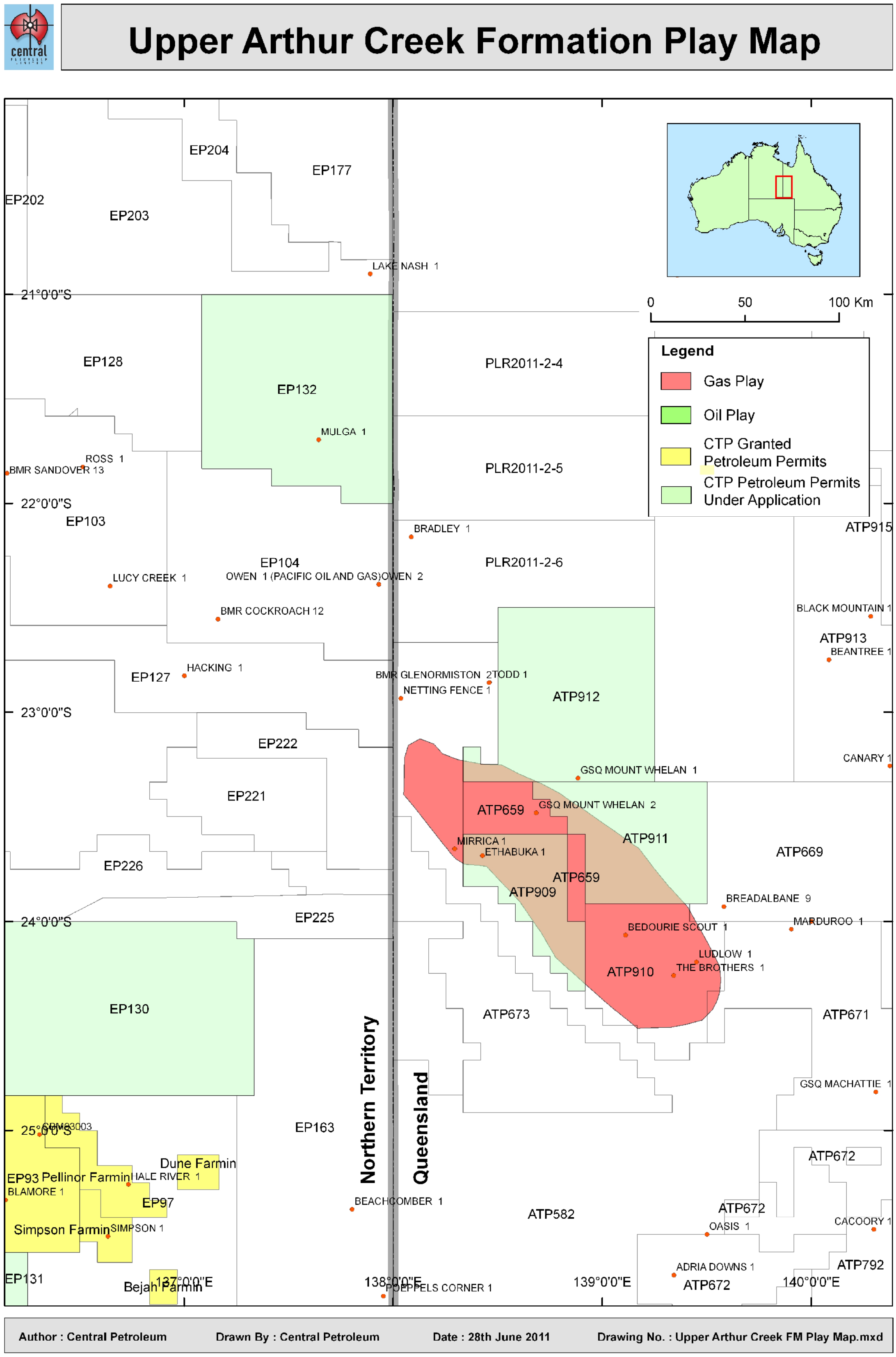
9 Appendix 2 - Southern Georgina Basin Unconventional Plays

There are 3 unconventional assessment units or plays within the Arthur Creek TPS:

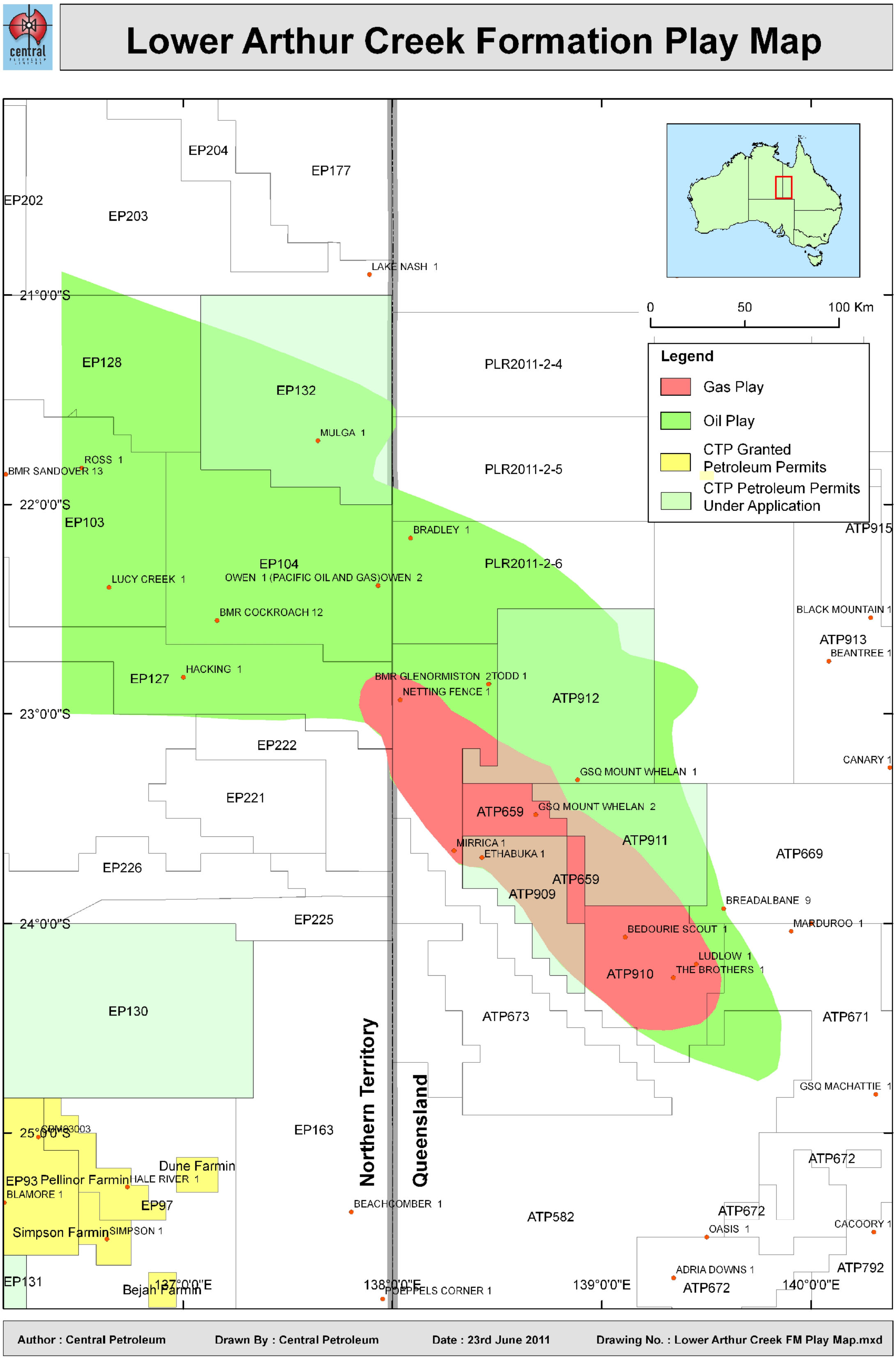
1. The Lower Arthur Creek (LAC)continuous gas assessment unit
2. The Lower Arthur Creek continuous oil assessment unit
3. The Upper Arthur Creek (UAC) continuous gas assessment unit



Diagrammatic Cross Section showing Unconventional Assessment Units (AUs) of Arthur Creek TPS



UAC Continuous Gas Assessment Unit



LAC –Continuous Gas and Continuous Oil Assessment Units.

Arthur Creek Shale Play - Technically Recoverable Resources

Assessment Unit	Technically Recoverable Prospective Resource (TCF or Billion BBLS)			
	P90	P50	P10	Mean
UAC Continuous Gas AU	4	11	30	15
LAC Continuous Gas AU	4	13	37	18
TOTAL GAS				33
LAC Continuous Oil AU	2	4	10	5
Total Oil				5

Georgina Basin Central Petroleum Prospective Resource

10Appendix 3 - Oil - Cash Flow Model Assumptions

The following are the assumptions for the 3 development scenarios used in the in the cash flow model to describe the likely range of EMV's for an unconventional oil development in Central Australia in the Georgina Basin:

Common Parameters

- All production costs and revenue are net company 100% share.
- Field size is 240 mill BBLS (4% of 6 Billion BBLS)
- Oil price is A$90/bbl real
- Depth to Target approx 1500 m
- CO_2 content negligible
- Development well cost initially A$6mill/well reducing to A$3.5 mill.
- Development well failure rate initially 20% dropping to 10%.
- 1000 km pipeline installed at cost of A$600 mill in 2017/2018.
- Initial production trucked & tolled at $30/BBL, later pipeline toll $10/BBL
- Provision made for handling 1,000 cuft /bbl GOR for use as fuel with surplus gas treated & piped 200km for A$190 mill to Carpentaria Pipeline for sale into Eastern Australia.
- Provision for CO_2 tax on fuel.
- Hybrid 15% royalty plus excise plus RRT

Scenario Upside (Big Company)

- EUR 637K BBLS/well and IR of 420 BBLS/day
- Production from 459 wells , with initial production in 1/1/2015.
- 16 gathering stations added as required, at $35mill/station.
- Cost of capital = 10%
- Full life capex A$3.3 billion (2011 $)

Scenario Middle

- EUR 455 K BBLS/well and IR of 300 BBLS/day.
- Production from 673 wells , with initial production in 1/1/2015
- 23 gathering stations added as required, at $35mill/station.
- Cost of Capital = 10%.
- Full life capex A$4.4 billion (2011$)

Scenario Downside (Little Company)

- EUR 273K BBLS/well and IR of 180 BBLS/day
- Production from 1276 wells , with initial production in 1/1/2015.
- 43 gathering stations added as required, at $35mill/station.
- Cost of capital = 12%
- Full life capex A$7.2 billion (2011$)

11Appendix 4 - Gas - Cash Flow Model Assumptions

The following are the assumptions for the 3 development scenarios used in the in the cash flow model to describe the likely range of EMV's for an unconventional gas development in Central Australia:

Common Parameters

- All production costs and revenue are net company 100% share.
- Field size is 5 TCF (8% of 59 TCF)
- Gas price is A$5.50/GJ real
- Depth to Target is 2000 meters
- CO2 content negligible, nitrogen 7.2%
- Development well cost initially $6.5mill/well reducing to $4 mill.
- Development well failure rate initially 20% dropping to 10%.
- 100 km pipeline for pilot gas & later condensate transport to railhead cost A$54 mill
- Gas treatment, condensate stabilisation & compression at pipeline inlet cost A$280 mill
- 1500 km combined gas and LPG pipeline & compression installed at cost of A$2.1 billion in 2017/2018
- Gas plant at pipeline outlet with LPG recovery cost A$350 mill.
- Provision made for handling condensate at 14BBLS/MMCF and LPG at 1.5 tonnes/MMCF.
- Provision for CO2 tax on fuel.
- Hybrid 15% royalty plus excise plus RRT

Scenario Upside (Big Co)

- EUR 10BCF/well and IR of 10 MMcfd
- Production from 1100 wells , with initial production in 1/1/2015.
- Cost of capital = 10%
- Full life capex A$9.7 billion (2011)

Scenario Middle

- EUR 5 BCF/well and IR of 5 MMcfd.
- Production from 1266 wells , with initial production in 1/1/2015
- Cost of Capital = 10%.
- Full life capex A$10.7 billion (2011)

Scenario Downside (Little CO)

- EUR 3BCF/well and IR of 3 MMcfd
- Production from 1317 wells , with initial production in 1/1/2015.
- Cost of capital = 12%
- Full life capex A$10.9 billion (2011

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17 August 2011

The Directors
Central Petroleum Limited
Suite 3 / Level 4 Southshore Centre
85 The Esplanade
South Perth WA 6151

Dear Sirs,

TECHNICAL NOTE ON APPRAISAL OF VALUE ADDED BY GTL FOR POTENTIAL NON-CONVENTIONAL GAS RESOURCES

Further to your request we have prepared the following Technical Note entitled " Appraisal of Value Added by GTL for Potential Non-Conventional Gas Resources" for consideration by the board of Central Petroleum Limited in respect of natural gas development opportunities in your central Australian acreage

This Technical Note is intended to provide specialist information on the potential value of GTL and its cost of production to support an independent geological study by Mulready Consulting Services Pty Ltd on the potential for non-conventional hydrocarbon accumulations in Central Petroleum's central Australian holdings.

Yours Faithfully

Dave Holt
Principal Mechanical Engineer
HCP Pty Ltd

APPRAISAL OF VALUE ADDED BY GTL

FOR

POTENTIAL NON-CONVENTIONAL GAS RESOURCES

TECHNICAL NOTE

Document No.
CPL–TN – 05

prepared by HCP Pty Ltd for Central Petroleum Limited

August 2011

SUBJECT: This report provides a brief appraisal of the value that could be added by Gas-to-Liquids (GTL) conversion of prospective gas flows from unconventional gas resources in Central Petroleum's acreage in the Amadeus and Southern Georgina Basins, Central Australia.

Issue	Description	Date	Prepared By	Reviewed By	Client Approved
0	Issued to Client	20 Aug 2011	D.J Holt		
A	Draft report for Client review	Aug 2011	D.J Holt	Various	

Appraisal of Value Added by GTL

for Potential Non-Conventional Gas Resources

Commissioned by Central Petroleum Limited,

July 2011

This report provides a brief appraisal of the value that could be added by GTL conversion of prospective gas flows from unconventional gas resource in Central Petroleum's acreage in Central Australia. It provides a preliminary appraisal of the technical and economic aspects of production and marketing of synthetic petroleum products utilising current gas-to-liquids (GTL) technology to process pipeline quality natural gas. This report does not attempt to produce profit forecasts for Central and should not be relied upon as a basis for investment in a GTL development for Central's prospective gas resources.

This report is intended to provide specialist information on GTL cost projections to support an independent geological study by Mulready Consulting Services Pty Ltd on the valuation of non-conventional hydrocarbon accumulations in Central Petroleum Limited's holdings in the Amadeus and Southern Georgina Basins, Central Australia. Mulready's report prepared by independent consultancy FSWPET Pty Ltd describes a fully risked 5 TCFG gas resource delivered by pipeline to Port Darwin as the basis for this appraisal.

The authors are competent persons with considerable experience in assessing GTL technologies, and the assumptions used and the conclusions reached in this report are considered by them to be based on reasonable grounds and appropriate for the scope of the assignment.

The report has drawn upon a number of sources including updated technical and cost related data for several new GTL projects now coming into service and other public domain data last researched July 2011 to derive an analysis of the possible commercial outcomes of a conceptual 50,000 bbl/day CTL plant located near Darwin in NT Australia.

Estimations of plant costs and other costs are likely to escalate over time, new and improved technology is likely to be developed and no forecasts of oil prices can be made nor is attempted except to note the trends of the past 25 years.

Disclaimer

Note about Authors

This report was prepared by Dave Holt, a Principal Consultant of Holt Campbell Payton Pty Ltd, a firm providing feasibility and costing analyses for a number of applications in energy project developments.

David Holt – MEngSc, M.E. – is senior partner in Perth-based consulting engineering practice (Holt Campbell Payton Pty Ltd). He has had extensive involvement with conceptual development and cost appraisal for a number of proposed coal-to-liquids projects including APEL's 60,000 bpd Latrobe Valley CTL project (now Monash Energy)

He has over 35 years in project development, project management and engineering in oil and gas and power fields. Relevant experience includes power station work with Collie coal, project management of Woodside's North Rankin gas recycling (enhanced condensate recovery) project, and owner's facilities engineer for OMV's Patricia-Baleen offshore gas field development in Eastern Victoria. He is a member of the American Society of Mechanical Engineers, AACE International (formerly American Association of Cost Engineers) and the American Nuclear Society

Table of Contents

1 INTRODUCTION

This technical note reports on a brief analysis of the profitability for a GTL plant in Darwin to add value to a 500 mmscfd stream of natural gas produced from gas fields in Central Australia over a period of 30 years.

Ideally one should consider a probabilistic approach around input cost as well as product prices, but in this case we have taken a simple approach and have considered a reliable supply of gas to be purchased at the gas hub in central Australia at $4.0/mscf gas price (year1) and transported by pipeline to the GTL plant at Darwin at a net cost of $1.50/mscf.

The GTL products (ultra clean diesel and naphtha) are presumed to be sold in Australia to meet the burgeoning demand in liquid transport fuels, which is anticipated to reach 112 million barrels per annum of imports in 2015 according the government sources.

An alternative scenario, to process the gas via a GTL plant located in central Australia has not been examined in this appraisal but may have some advantages in reduction of the gas from-field-to-plant costs, presuming product could be shipped out via the existing north-south rail link.

The discounted cash-flow analysis shows that production of a large gas field in central Australia, which might not be economically feasible at $4.0 gas price, could be converted to GTL and make 18% ROI (after tax).

In his “Energy: the state of the nation” speech on March 18,2008, the Federal Energy Minister, Martin Ferguson said: “Australia could face a trade deficit in petroleum products of more than $25 billion by 2015 and domestic oil production could be as little as 20 per cent of our needs compared with 80 per cent in the 1990s.”

This is similar to the forecast of Belinda Robinson, (Australian Petroleum Production and Exploration Association, “Energy state of the nation”, March 7, 2007):
“Using Geoscience Australia projections and assuming oil prices of US $50 a barrel, ... the deficit for oil, condensate and refined products is projected to increase to $27 billion a year by 2015 -- around twice the 2005-06 deficit of $12.8 billion.”

2 GTL OPTION FOR CENTRAL PETROLEUM

The objective here is to determine a most profitable means to market a notional 5TCF of pipeline quality natural gas which would be conveyed by pipeline to Darwin from gas fields located in Central Australia. The base case is to supply approximately 500 mmscfd gas to "a plant" in Darwin over a period of 30 years. Central Petroleum has determined that the minimum value of the gas upon delivery at the pipeline terminal at Darwin would be $5.50/mscf at the start of the project. We assume that the delivered value of the gas would increase over time in line with crude oil marker prices.

3 GAS-TO-LIQUID (GTL)

Synthetic fuels are a new generation of near zero sulphur and aromatics transport fuels made with the Fischer Tropsch process from natural gas (GTL), coal (CTL) or biomass (BTL). The process produces typically 70 percent synthetic diesel and 30 percent naphtha, a premium sulphur-free chemical feedstock which is also an excellent gas turbine fuel.

Previously, a modest amount of synthetic diesel was being made commercially by Shell (Malaysia) and SASOL and PetroSA (South Africa). However, several new large scale GTL plants are now coming into service and product availability (although representing only a relatively small fraction of total middle distillate products on the world market) is expected to increase significantly in the next few years. The first of these, the 34,000 bpd "Oryx" GTL plant in Qatar, jointly owned by SASOL and Qatar Petroleum, came into full production in 2008. The largest plant now coming into production is the Qatar Shell ("Pearl") GTL facility which will process 1400 mmscfd (0.5 TCF per year) of dry gas to produce 140,000 bpd of GTL fuels. Outside Qatar, Chevron Nigeria, together with NNPC, is building a 34,000 bbl/day GTL plant in Escravos, Nigeria. Escravos GTL is of similar capacity and technology to Oryx GTL. Construction is currently about 70% complete and the plant is due to start up in 2013.

4 LOCATION SELECTION: WHY DARWIN AND NOT ALICE SPRINGS?

Although a fully risked 5 TCFG gas resource delivered by pipeline to Port Darwin has been used as the basis for this appraisal, there are also merits for locating a GTL plant in central Australia. Some of the pros and cons are mentioned below and an ultimate selection process would have to consider these aspects.

Firstly, the logistics of building a large scale GTL plant away from any major industrial centre would be difficult. As a point of reference, the 34,000 bbl/day ORYX GTL plant in Qatar took 21.5 million site manhours to construct over a period of 33 months. This was on an industrial park where a prepared site with power, water, waste handling, seawater cooling, clean gas feedstock and product export facilities were all provided. If this plant had been built on a green-field site the construction scope would have been around 50 percent more (some 33 million manhours). This equates to a peak workforce of around 11,000. A GTL plant nearly twice this size and built over the same time scale would be expected to require double the manpower ~ a peak workforce of about 20,000 or so.

However, as has been the experience in Western Australia, remoteness has been no barrier to constructing a large scale process plant close to its source of feedstock. Chevron's Gorgon LNG project, for example, is being built on Barrow Island, an 'A' Cass nature reserve, on a Fly-In-Fly-Out basis and includes a 3,000-plus person accommodation village on the Island. Another example is BHPB's Ravensthorpe nickel project about 540km south-east of Perth where most of the construction work was done on a fly-in-fly-out basis. The cost up-lift for a project in this location compared with Perth region was considered to be about 15%. It is assumed that a similar cost uplift might apply to a GTL plant constructed in central Australia compared with a Darwin location.

A 500 mmscfd pipeline to Darwin location would offer the opportunity to produce either LNG or GTL or both in response to market demands. It could also benefit from the competitiveness of joining a market hub with the other three gas operators (ConocoPhillips, Inpex, Eni Blacktip).

If the GTL plant was to be located in central Australia, however, there would be a major benefit in not having to pipe the gas to Darwin which would otherwise add about $15 to the cost of a barrel of GTL. This would be offset to some extent by the cost of rail freighting the product to port which could be about $7 per barrel (based on 2008 interstate non-bulk freight rates published by the Bureau of infrastructure, Transport and Regional Economics). It is expected that a central Australian GTL plant would also be better positioned for delivering liquid fuels by rail to the major market regions of Adelaide and Eastern states.

There is another aspect too. GTL is being viewed as a significant source of jet fuel for the future. An airline like Qantas is dependent on a secure and affordable source of fuel for its international services to remain competitive against other operators (such as Emirates) who might have their own national fuel supplies. With a large scale GTL plant in central Australia, it is not inconceivable the Alice Springs could become a major refueling stop for aircraft on the international routes. Presently, this function is served by Sydney airport which dispenses some 50,000 bbl of jet fuel each day. The demand is projected to grow to 95,000 bbl/day by year 2029

5 CAPITAL INVESTMENT

Current CAPEX estimates are based on Oryx which (reportedly) came in at around USD1050 million. If it had been a green-field development, CAPEX would have been expected to be some 50% more (~ USD1600 million.) The increase in plant construction costs since they started building that plant has been about 55% according to IHS CERA downstream plant cost index. This computes to CAPEX of ~ 73,000 USD/daily barrel. Hence the typical number being used in some studies today is around USD 75,000/bpd.

CAPEX for Shell's Pearl GTL project is expected to total around USD20 billion when completed next year. This is for the total project which also includes offshore platforms, trunklines, 1.6 bcf/d onshore gas plant and 120,000 bpd condensate export facility. Shell has never given a cost breakdown but analysts assume that two thirds of the project CAPEX would be allocated to the GTL plant and the other third to field production and gas plant. This would compute to CAPEX of ~ 95,000 USD/daily barrel.

Shell's technology is based on replication of the process developed and proven at Bintulu and is considerably more plant intensive than Oryx which probably accounts for much of the higher CAPEX. But it is known to work.

Estimated costs of the proposed Alaskan North Slope GTL plant have been based on a $92,000/ installed barrel cost. The proponent, Alaska Natural Resources To Liquids, LLC (ANRTL) considers that the projected costs of a North Slope GTL plant program are on the high side, even taking into account the extreme weather conditions.

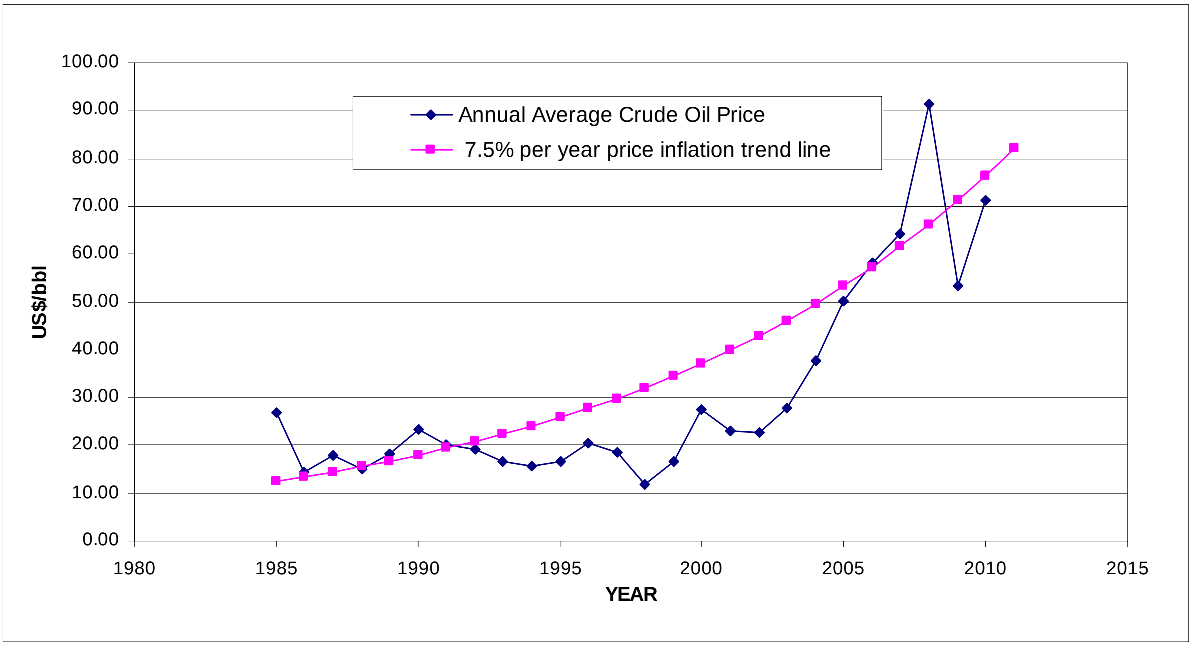
A realistic approach for Central might be to assume that such a project would be carried out with one or more major partners each having special expertise and end market experience. The way joint ventures operate would require a low risk approach and for that reason it would be prudent to assess the viability based on verifiable conservative economic assumptions. In this case it is suggested using a specific CAPEX of US$90,000/bpd to give a total plant investment of around US$4.5 billion for the 50,000 bpd GTL plant.

6 PRODUCT VALUE

In the absence of an established commercial market for GTL products, analysts tend to consider a minimum value for the product as a clean safe substitute for petroleum based fuels, as follows:
- FT diesel value ~ 1.3 times crude price
- FT naphtha value ~ same as crude.

High value attributes such as special long shelf life, high purity food waxes and specialty hydrocarbons, and ultra-low sulphur diesel blend-stock applications have not been taken into account for this appraisal. These attributes, however, do suggest that GTL is likely to be valued upwards of its petroleum fuel replacement value.
Most GTL feasibility studies seem to be based on a capacity factor of 90% (330 days operational per year)

Crude Oil Historical Price Movement



data from: http://inflationdata.com/Inflation/Inflation_Rate/Historical_Oil_Prices_Table.asp

Petroleum Price escalation

No attempt is made to predict the future price of crude at any point in time since oil prices have exhibited enormous fluctuations from time to time in response to various global political instabilities and the consequential effects on availability of quality crudes.

It is observed, though, that the value of petroleum has been increasing at an average of 7.5% per year for the past 25 years and that the factors causing this increase are unlikely to disappear in the foreseeable future.

This suggests that the value of petroleum products could double in the next ten years. We assume that the value of natural gas would be linked to petroleum and that, at least over the long term, it could be expected to escalate at the same average rate.

7 LNG vs GTL

The Central Australia natural gas project envisages using 500mmscfd of gas as feedstock to produce 50,000 b/d of sulfur-free premium synthetic diesel and naphtha Central could either process this gas into LNG or use a GTL plant to produce petroleum products.
Converting the gas to LNG at the usual conversion efficiency of 85% would yield 425,000 MMBtu of LNG. The July '11 Platts marker price for LNG FOB Australia was $12.67/MMBtu, with means that if sold as LNG that gas could fetch some $5.4 million per day.

At the same time, the marker price for "low-sulphur" (50 ppm) diesel FOB Singapore was $130/bbl which means that a 'barrel' of GTL liquids (70% diesel : 30% naphtha) could probably sell for about $120. Thus, if sold as GTL liquids, the daily natural gas feed could be worth around $6.5 million, some 20% more than for the LNG. However, the costs associated with the gas-to-liquids process are currently significantly higher than for liquefaction.

Based on projected costs announced recently for several LNG plants proposed for Gladstone, Qld, a 3Mt /year LNG plant would be expected to cost around $2.1billion, whereas the GTL plant processing the same quantity of feedstock would be expected to cost some $4.5 billion.

It is noted that the value of petroleum has been increasing at an average of 7.5% per year for the past 25 years and that the factors causing this increase are unlikely to disappear in the foreseeable future. This suggests that the value of petroleum products could double in the next ten years, widening the revenue advantage of GTL over LNG. At the same time, the initial capital investments in plant would be partly amortised, thus narrowing the processing cost advantage of LNG over GTL.

The energy market, particularly in North America, is quite dynamic and can change quickly. A prudent approach to evaluate LNG versus GTL is to start from end-market. It is quite conceivable that the LNG price could be floating and the oil-linked gas or

LNG contracts in Asia will disappear in 3-5 years. In this case the lowest risk option would be to convert gas to GTL to capture all the value in the value-chain and so lock into the oil price. However, if the LNG price is expected to hold firm for the next 10-20 years then LNG would seem to be a more logical choice as only 15% of the feedstock gas (compared to 40%-50% in case of GTL) is used in the conversion and the benefit of high margin per GJ would still be retained.

This highlights some of the uncertainties of valuing gas in the ground. As one Platts analyst recently put it," an incremental amount of gas in Qatar is likely to be valued on the basis of everything from LNG prices in Japan to diesel prices in the US" .("Pearl GTL Rolls Out" , Platts-"The Barrel"2011/06/17)

8 CENTRAL AUSTRALIA GTL PLAN ECONOMIC CASE:

Plant
Location: Darwin port industrial area
Capacity: 50,000 b/d liquid output
Plant capacity factor: 90% (330 operational days per year)
Annual production: 16.5 million bbl
30 yr flat production
Capex (TDC): $4.5 billion (or $90,000 per output capacity b/d)

Feedstock
500 mmscfd pipeline quality gas for 30 years
Gas delivered to plant by pipeline from CTP's gas fields in Central Australia
Custody transfer price of gas at plant: $5.50/ mscf *
Average price escalation rate 7.5% (assumed similar to crude price)
Average consumption 10 mscf/barrel GTL
* mscf means 1000 std cu ft

Product Output
High grade diesel: 70% (30% premium over WTI crude)
Naphtha: 30% (same as WTI crude)
GTL yr1 product value: $120 / bbl (based on $100/bbl crude)
Average price escalation rate 7.5% (25 yr historical average for crude price)
Plant operating and maintenance cost (~ 3.2% of TDC) : $8.50 /bbl output

Some Economics for the Project
from Discounted Cash Flow analysis (Section 9)

-IRR: 20.0% (0 debt share)
-IRR: 18.2% (60% debt share at 8%pa)
-IRR: 14.8% (assuming only CPI escalation for GTL product, 0% debt share)
-IRR: 12% (assuming only CPI escalation for GTL product, 60% debt share at 8%pa,)

-NPV: $10.0 billion (@10% DF) (0 debt share)
-NPV: $8.1 billion (@10% DF) (60% debt share at 8%pa)
-NPV: $5.0 billion (@12% DF) (60% debt share at 8%pa)
-NPV: $2.0 billion (@15% DF) (60% debt share at 8%pa)

Cost of Production

Estimated initial cost of production per barrel for the GTL plant is as follows:

Cost Component	Ref. Rate	US$/bbl
Natural Gas Feedstock [10.0 mscf/bbl]	A$4.00/mscf *	40.0
Gas Transmission to Darwin	A$1.50/mscf	15.0
Capital (assumed 90% capacity factor)	14%pa of TDC	38.0
Rates, Prop.Taxes, Insurance	2%pa of TDC	5.5
Operating and Maintenance	3.2% of TDC (typ)	8.5
Transport from Plant to Port	N/A	-
Total Cost of Production		**107.0**

* mscf means 1000 std cu ft

It is assumed that this project could be debt financed up to 60% of TDC for a period of twenty years at fixed interest of 8%p.a.

The capital charge rate used in this calculation (14%) is a minimum sustainable rate derived to cover depreciation (5%), fixed interest on debt capital (8% of 0.6) and a pre-tax return of 10.5% on the 0.4 equity funding

A delivered cost of US$107.0 /bbl would be the same as the landed cost of similar petroleum products imported from Singapore with Dubai crude at US$88 /bbl.(based on pricing assumption of premium FT diesel at 1.3 x crude price and naphtha same value as crude). We have assumed here that the cost of shipping the product from Darwin to Eastern states markets would be similar to the cost of shipment from Singapore.

Cost Sensitivities

The table below indicates how a 10% change in any of the cost elements would affect the cost of producing GTL

Cost Component	Value Change	Change in Cost per Bbl
Natural Gas Feedstock [10.0 mscf/bbl]	10%	3.7%
Gas Transmission to Darwin	10%	1.4%
Capital (assumed 90% capacity factor)	10%	3.6%
Rates, Prop.Taxes, Insurance	10%	0.5%
Operating and Maintenance	10%	0.8%

9 DISCOUNTED CASH FLOW ANALYSIS

A DCF analysis is presented here based on the following assumptions:

Construction Period	3	years
Project Total Depreciable Capital (TDC)	4500	$m
Escalation Factor	2.80%	
Pre-tax net revenue, Year 1 of Project	931	$m
Prop Tax & Insurance	2%	
Tax rate	30%	
Debt rate	8%	
Discount rate	12.00%	
Debt Share	60%	
Loan duration	20	years
Crude price Yr1	100	$/bbl
GTL product value Yr1 (calculated value)	121	$/bbl
GTL product value escalation rate	7.5%	p.a.
Annual capacity factor	330	days/year (eqiv)
Feedstock price Yr1 (delivered)	5500	$/mmscf
Feedstock price escalation rate	7.5%	p.a.
Operations & Maintenace + O'hds	8.5	$/bbl
O&M + O'hds escalation factor	2.80%	

Construction Cost Nominal $	Construction Real Yr 1 $ * (1+Escalation Rate)^(Period-Year 1 Period)
Interest During Construction	(One half of Nominal Construction Cost + previous year's Cumulative Construction Cost) * Debt Rate.
Cumulative Tax Basis	Cumulative Construction Cost + Interest During Construction.
Tax Depreciation	Cum. Tax Basis * Tax Depreciation Schedule.
Debt Servicing:	Fixed interest on principal. Payback of full principal at end of term
Insurance (Ptax & Insur)	Cumulative Tax Basis * Property Tax & Insurance rate.
Revenue	Project revenue. For IRR and NPV calculations, Revenue values are input. For FCR calculations, Revenue for first year after construction is completed is calculated. For all calculations, year 2 onward is grown at Escalation Factor.
Taxable Income	Revenue - Tax Depreciation - Property Tax & Insurance
Income Tax	Taxable Income * Tax Rate.
Cash Flow	Taxable Income - Income Tax + Tax Depreciation
Yr.1 Present Value - Cash Flow	For IRR calcs = Cash Flow / (1+IRR)^Period For NPV and FCR calculations = Cash Flow /(1+WACC)^Period

IRR Net Present Value (NPV) Worksheet

Period	Constr Payment Timing	Constr Real Yr1$	Constr Cost Nom $	Interest During Constr	Cumul Tax Basis	Tax Deprec Schedule	Tax Deprec'n	Debt Servicing	PTax & Insurance	Feedstock cost (delivered)	O&M & O'hds	FT Liquids Revenue	EBITDA (Net Revenue)	Taxable Income	Income Taxes	Cash Flow	Yr1 PV to Investors Cash Flow
-3	0	0	0	0	0											0	0
-2	33%	1500	1381	55	1436											-1436	-1801
-1	33%	1500	1419	172	3027											-1591	-1782
0	33%	1500	1459	301	4787			2872	96	908	140	1997	853			-1760	-1760
1						5.00%	239	230	96	976	144	2146	931	462	139	563	502
2						5.00%	239	230	96	1049	148	2307	1015	545	164	621	495
3						5.00%	239	230	96	1127	152	2480	1105	636	191	684	487
4						5.00%	239	230	96	1212	157	2666	1202	733	220	752	478
5						5.00%	239	230	96	1303	161	2866	1307	838	251	826	468
6						5.00%	239	230	96	1401	166	3081	1419	950	285	905	458
7						5.00%	239	230	96	1506	170	3312	1541	1072	322	990	448
8						5.00%	239	230	96	1619	175	3561	1672	1202	361	1081	437
9						5.00%	239	230	96	1740	180	3828	1812	1343	403	1180	425
10						5.00%	239	230	96	1870	185	4115	1964	1495	448	1286	414
11						5.00%	239	230	96	2011	190	4423	2127	1658	497	1400	402
12						5.00%	239	230	96	2161	195	4755	2303	1834	550	1523	391
13						5.00%	239	230	96	2324	201	5112	2492	2023	607	1655	379
14						5.00%	239	230	96	2498	206	5495	2695	2226	668	1798	368
15						5.00%	239	230	96	2685	212	5907	2914	2445	734	1951	356
16						5.00%	239	230	96	2887	218	6350	3150	2681	804	2116	345
17						5.00%	239	230	96	3103	224	6827	3404	2935	880	2294	334
18						5.00%	239	230	96	3336	231	7339	3677	3208	962	2485	323
19						5.00%	239	230	96	3586	237	7889	3970	3501	1050	2690	312
20						5.00%	239	230	96	3855	244	8481	4287	3817	1145	40	4
21							0		96	4144	250	9117	4627	4627	1388	3239	300
22									96	4455	257	9801	4993	4993	1498	3495	289
23									96	4789	265	10536	5386	5386	1616	3770	278
24									96	5148	272	11326	5810	5810	1743	4067	268
25									96	5534	280	12175	6266	6266	1880	4386	258
26									96	5949	288	13088	6756	6756	2027	4729	248
27									96	6396	296	14070	7283	7283	2185	5098	239
28									96	6875	304	15125	7851	7851	2355	5495	230
29									96	7391	312	16260	8461	8461	2538	5923	221
30									96	7945	321	17479	9117	9117	2735	6382	213
Totals	1	4500	4259	527	9250	100.00%	4787		2968				112387	102152	30646	68634	5030

10 RISK FACTORS

This conceptual GTL project is based on having a 500mmscfd gas supply available at the Darwin location at a price of $5500 per mmscf. It is further assumed the the gas supply and the GTL plant will together have sufficient redundancy and back-up resources to provide the availability to produce GTL products for not less than 90 percent of the year.

Security of Supply

Notwithstanding such measures, there is the risk that the GTL plant might not be able to source adequate quantities of feedstock from time to time. In the event of difficult circumstances, such as inflexible commitments to supply GTL to customers or inability to source replacement GTL, the possibility may exist in Darwin to source partial quantities of replacement feedstock from one of several other major gas producers with terminal facilities in Darwin (e.g. ConocoPhillips, Inpex, ENI Blacktip). This might not be the case if the plant was located in Central Australia.

Risks of Project Cost Overruns

For this cost appraisal we have conservatively used a high specific CAPEX value ($90,000/ daily GTL bbl capacity) similar the what Shell is understood to have spent on its Pearl GTL plant in Qatar. Alaska Natural Resources To Liquids (ANRTL) has used a similar specific capex value for its proposed Alaska GTL project and believes it to be high even for a GTL plant built in the severe environment of Alaska. We have factored in the additional cost of cyclone rated construction standards but still consider the capex figure to be about 10% higher than a reasonable target price.

Nevertheless there are a number of factors that often result in cost overruns on Australian resource projects including:

- Industrial activity (considered low risk in Darwin)
- “Overheated Construction Industry” due to many other projects being active at the same time and strong competition for materials, construction workers and management expertise (quite likely).
- Delays caused by major accidents, native title disputes, weather, cyclones
- Possible second wave general economic downturn
- Insolvency of one or other of the JV partners

According to PennEnergy (1 March 2011), the outlook for GTL remains bright, despite major cost overruns. Chevron's 34,000 bbl/d Escravos gas to liquids (EGTL) project in Nigeria ,which is 70% complete, has suffered further cost overruns, and is now expected to come into service in 2013 at a total cost of US$8.4bn, some five times the cost originally estimated. Cost overruns and delays have been a common problem over the past 10 years for GTL projects, which are typically highly complex, large-scale facilities. The huge potential profits provided by GTL, however, particularly in the light of strong oil/gas price differentials, means that despite these problems there is no shortage of companies willing to invest.

Risks of not achieving adequate returns

PennEnergy noted that GTL projects are becoming more attractive as a result of severely depressed gas prices, particularly in North America, where rising shale gas production has significantly increased supply. With oil prices having increased substantially over 2010, the economics of GTL have begun to look extremely promising.

Another factor which should not be overlooked is the degree of confidence that some major petroleum companies have shown in proceeding with large scale GTL developments, notably Shell's "Pearl" GTL development in Qatar (a $20 billion investment) and Chevron's Escravos GTL project in Nigeria with capital outlay now approaching $8.4 billion. The Escravos project in particular, shows the value of GTL to Chevron when it is prepared to continue with the project with specific costs approaching $250,000 per daily barrel

Possible carbon tax impact?

Since the natural gas feedstock for GTL contains nearly twice as much hydrogen as is required for the product, the process is short on carbon. Ongoing technology development has been directed, among other things, towards maximum utilization of the carbon available in the feedstock. The FT liquids produced do have a lower carbon footprint than petroleum derived fuels. If and when a carbon tax or cap-and trade regime is introduced it would seem unlikely that this could have any negative impact on a GTL development

Destruction of market demand (possible but unlikely)

Based on the present political climate and future directions of technology growth, a strong growth in demand for GTL products is expected in Australia over the next few years, particularly aviation fuels, for which there is little opportunity to employ renewables.

An outlook for the Australian fuels market as perceived by Caltex Australia is included in the following section.

11 AUSTRALIAN FUELS MARKET

The Australian transport fuels market is dominated by fuel refined in Australia from local or imported crude. Currently, roughly 70% of refinery feedstock is imported, the remainder being supplied from declining local resources. Furthermore, about 44 percent of the diesel consumed in Australia over the period 2008-09 was imported as refined product (52 million bbl/year), mainly from Singapore.

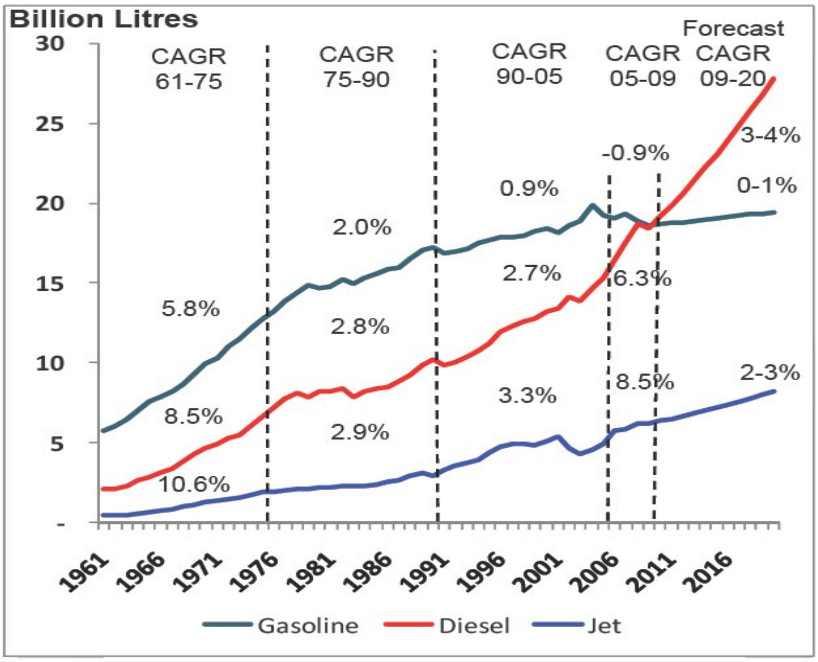
Australian production of refined petroleum products

There are currently seven major oil refineries operating within the vicinity of five capital cities run by four refining companies: Caltex Oil Australia Pty Ltd (Caltex), BP Australia Ltd (BP), Mobil Oil Australia Ltd (Mobil), and The Shell Company of Australia Ltd (Shell). With the exception of Caltex, the other three oil refiners are wholly owned subsidiaries of multinational oil companies: the UK based BP PLC; the US based ExxonMobil Corporation; and the Anglo-Dutch Royal Dutch Shell Group. Caltex is a listed Australian public company with a 50 per cent interest held by Chevron Global Energy Inc and the rest by more than 20,000 shareholders. While Shell, BP and Mobil each operate as part of a global business, Caltex Australia operates as an independent entity.

The total production capacity of the seven refineries in Australia is about 760,000 bpd which is less than that of just one of several big Asian refineries (for example, the capacity of the Reliance Petroleum Ltd refinery in Jamnagar, India is 1.2 million bpd)

Australian demand outlook

According to Caltex Australia's report, the industry outlook is for strong Australian demand growth for diesel, jet fuel and premium fuel, with future growth leveraged to Asian growth.



Source: Caltex Australia CAGR = Compound Annual Growth Rate

Diesel demand growth has been underpinned by GDP growth chiefly by the mining and transport sectors while jet fuel demand growth is linked to increasing passenger travel due to expected economic activity and increasing prosperity

While overall demand growth for gasoline (petrol) is expected to remain relatively flat, more rapid demand for higher octane, premium gasoline is expected.

The biggest challenges now facing Australian oil refiners are:

- Refining costs for the older and smaller Australian refineries are considerably higher than those for the new large scale refineries now coming on stream in Asia

- Weaker global product demand and higher product shipping capacity has markedly reduced crude / product freight differential [US$2.90/bbl in 2007 to

US$1.60/bbl in 2009] further reducing location advantage of Australian refineries.

- Pressure to import refined fuels from more cost effective sources of supply in Asia may see a reduction in local refining capacity and perhaps closure of some refineries. The main concerns are about a loss of petroleum refining expertise

Outlook to 2020

With increasing demand for petroleum based liquid fuels outstripping any possible expansion in domestic refining capacity, Australia's reliance on imported refined petroleum products will continue to increase. This will put greater reliance on the adequacy of infrastructure available to support the importation of refined petroleum products. The four major petroleum companies have moved strongly into retail marketing, placing emphasis on developing greater import capacity rather than expanding refining facilities

Caltex' objective is to capitalise on the expected growth in the diesel market through strategic investment in new infrastructure in the key market segments of North Western Australia and Queensland.

Self Sufficiency Argument (author's personal opinion)

The Australian Government has been urging for greater self-sufficiency in petroleum products, citing the fact that the national trade deficit in crude oil and petroleum products is $16 billion a year in 2010 and was expected to reach $30 billion by 2015. However, this focus on the trade deficit in petroleum products belies the fact that there are countervailing trade surpluses in coal and gas, currently $55 billion per year and $10 billion per year respectively. The real impetus for greater self sufficiency would seem to be national security as is the case in the United States where the most serious concern is about being able to fuel the armed forces when a large proportion of the nation's fuel has to be imported

As the Australian Government recognised in its 2009 National Energy Security Assessment, liquid fuel security will decline significantly if more Australian refineries close.