Revision 4   07/12/18 Issued as a Preliminary Draft

This post does not contain investment advice DYOR before making any investment decisions.

It started off as a document for my own reference and I decided to share it in the hope that other CTP shareholders may gain some benefit by using it as a framework for research.

1.00 Executive Summary

The present CTP share price appears to be weighed down by poor investor sentiment which has been slow to respond to Central's future potential after it was clear that a pathway to sell gas to East coast markets would to be available at the end of 2018.

I hold the strong opinion the approach CTP has used to achieve communication with shareholders is a major contributing factor to this poor market sentiment.

Instead of underpinning the share value of CTP, the SOA seems to have created a ceiling in the minds of many investors.

The shareholder base, now increasingly well informed by the SOA documentation, has not been given an adequate plausible explanation as to why the CTP board behaved so unpredictably when they accepted such a low SOA proposal.

The high level explanation for the board's strong recommendation was the realisation that CTP would be unable to obtain the funding that was needed to undertake the future business plan.

After a long silence CTP have come been successful in raising sufficient capital to finance a 20M 4 well horizontal drilling appraisal program similar to that documented in considerable detail in the SOA.

At the AGM webinar it was explained that CTP planned to refinance their future operations in one hit late 2018 underpinned by completion of the reserve certification exercise and an assured pathway to markets down the NGP.

The SOA however identifies an extensive scope of work that would need to be undertaken on Mereenie surface facilities in order to supply 60TJ/day in time for NGP first gas late 2018.

Comment made at the AGM webinar indicated that the Mereenie facility could process the first gas requirement with only minor expenditure.

Suddenly the whole rationale behind the board's strong recommendation to accept the SOA has evaporated without a plausible explanation.

This credibility gap is no doubt weighing heavily on CTP shareholder sentiment.

After shareholders voted to reject the SOA the CTP spin doctor/s presented the result as overwhelming support of the CTP board.

Perhaps I was the only one that saw that the overwhelming majority of shareholders had accepted the reality that the CTP board was cornered and unable to come up with a business plan to achieve a better result.

So here we are faced with a few harsh realities but apparently have a business plan that gives us a fighting chance of earning at least 30M/year, as long as we can fulfil our 30TJ/day share of the NGP, with the ability to increase this as the capacity of the pipeline to the East coast market is upgraded.

Since the SOA was rejected by shareholders, a straw-pole overwhelmingly points to the perception that CTP have only provided a sketchy version of the scope and timing of the mission critical activities that need to be achieved between now and first NGP gas in late 2018.

We only have one chance to get 60tJ/day of gas down the NGP late 2018.

Shareholders who have had their fingers burnt over the years will no longer be satisfied with "Everything's going to be all right" and "Don't you worry about that", business plans.

We want to see a realistic and plausible project management plan to achieve NGP first gas on the table.

CTP needs to not only deliver value to shareholders they need to be seen to be delivering it.

The one positive outcome for shareholders from the SOA was the extensive body of information that was provided to support the board's recommendation to accept it.

Since most shareholders have suffered significant losses with a consequential loss of faith in the CTP board, the bar for the standard of disclosure to restore market sentiment towards CTP has now been raised far beyond the minimum legal requirement.

CTP shareholders are now much better informed and the expert submissions contained in the SOA have established a new benchmark for the standard of communication that CTP shareholders require from the CTP board and management.

In short the CTP team are dealing with a shareholder base that is better informed and much more wary.

Central is now competing with a number of other gas centric low cap juniors whose share prices over the last 12 months have increased significantly in response to their business strategies to take advantage of the East Coast Gas Shortage.

This is in spite of the fact that these O&G juniors are not in Central's enviable position of supplying GSA's to 2 NT power stations which will make it cash flow positive in 2018.

The ability to rapidly access information through internet based search engines combined with the power of social media is now playing an increasingly important role in influencing shareholder sentiment.

I think it is about time CTP recognised this and dispensed with the luxury of their reluctance to give shareholders enough credible information for them to understand "What's Going On".

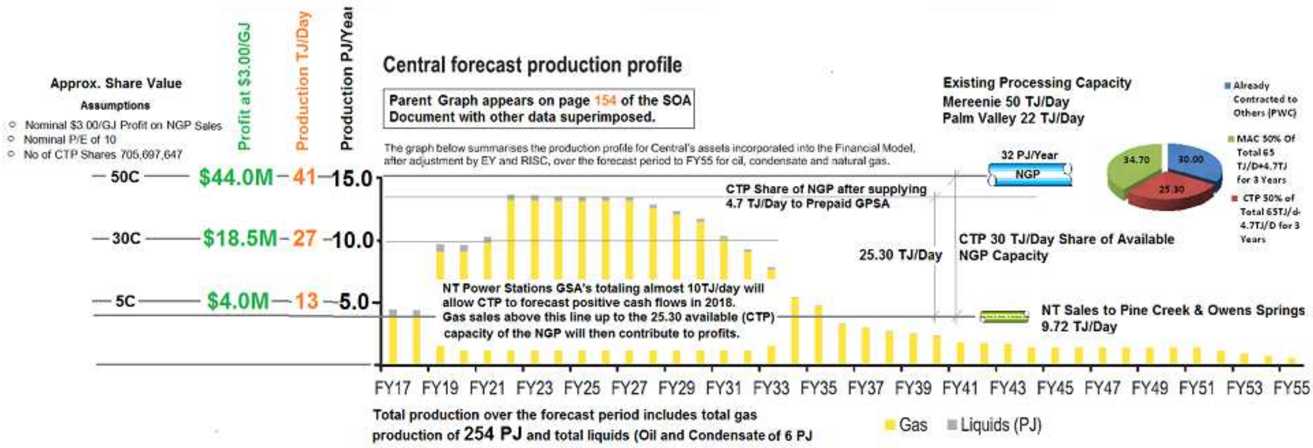
The CTP business plan between now and first gas down the NGP needs to be presented in much more detail, a lot more Information Flow Headings are needed.

Risks to the business need to be clearly explained so that shareholders can to be confident that CTP management have a well thought out risk management and mitigation plan on place.

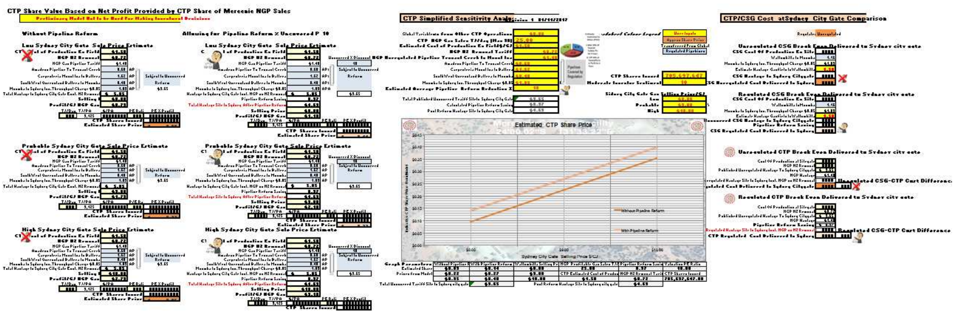
On the positive side, if the prognosis behind the appraisal program is successful, it will result in a significant increase in the (Net to Central) 2P reserves to between 352.9 to 541.4 PJ and establish the feasibility of horizontal drilling technology to economically obtain sustainable flow rates to service the existing GSA's to 2 NT power stations totalling 10TJ/day as well as supplying an additional 30 TJ/day to the East Coast market as soon as the NGP is commissioned.

Coming to Grips with the Potential Post NGP Medium Term Share Value based in Gas sales

The following Montage was first assembled to provide a simplified overview of Post NGP production using a parent graph from the SOA is explained in more detail in the attached PDF which expands on the above summary.



Using it as a frame of reference the following simplified sensitivity analysis spreadsheet model was built to assist in reviewing what if scenarios relating variables such as production cost haulage uncovered piping tariffs Etc.



The graph below taken from the sensitivity model shows the potential impact on the share price of production costs, N2 removal, haulage, pipeline reform, selling price, TJ/Day sold to East coast markets over a range of nominated selling prices at Sydney city gate. **.**

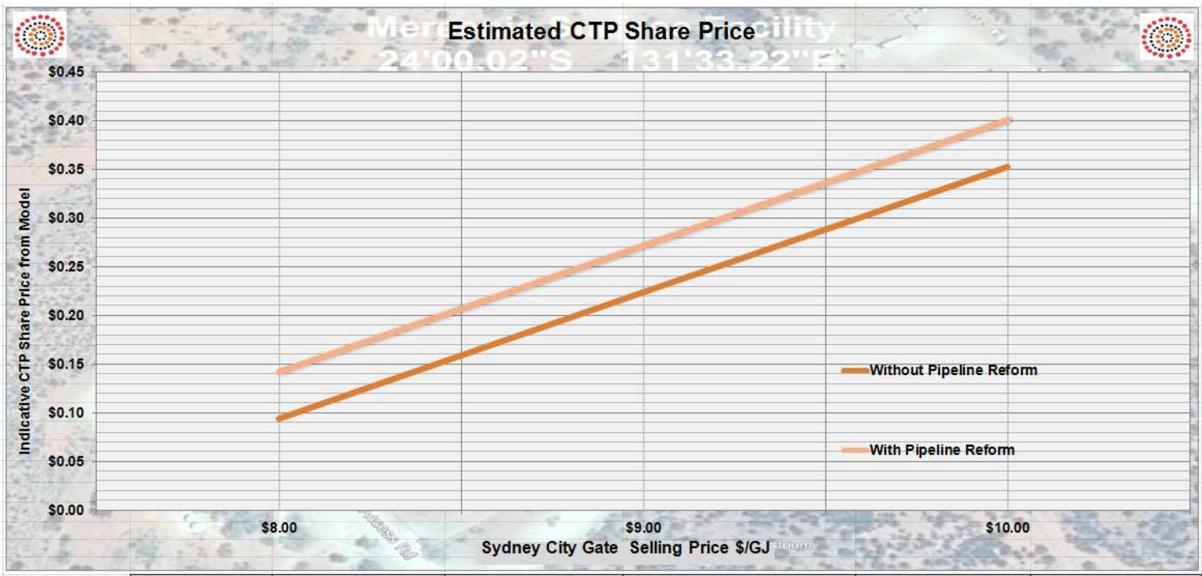
- The spreadsheet model makes the simplistic assumption that CTP is now cash flow positive with our current nominal 10TJ/day NT sales Etc. and that 25 TJ of gas down the NGP will drive profits but has provision to nominate a plug in amount for the estimated annual profit/loss from Other CTP Operations.
- I contacted APA today & checked the published unregulated rates.
- The NGP of course being a new pipe is not covered by regulation.
- Hopefully our gas will not need the full N_2 NGP removal tariff on but we will have to wait for drilling results to see.
  - It is my opinion that if we can Certify enough reserves & flow rates that we may be able to negotiate HOA for a long term discount with APA on the published haulage rates as a safety net in case pipeline reform is not implemented in time for NGP first gas late 2018.

The graph below was set at a 10% pipeline reform discount on stated uncovered tariffs, which IMO may be possible through negotiation, so you can see the difference this would make to the estimated share value over the Selling Price Range.

The first thing that the graph implied was that CTP would need to achieve more than a $9.00 Sydney city gate selling price.

Regardless of the inherent inaccuracy of this simplified business model it serves to show just how sensitive CTP's profitability is to any change in the fundamental parameters and to market sentiment affecting the P/E ratio.

By the way the share price without the benefit of pipeline reform and a P/E of 9 just happens to come in at 20C!



Graph Parameters	Without Pipeline Reform	With Pipeline Reform	Wallumbilla Selling Price	NGP Profitable Gas Sales TJ/Day	Pipeline Reform Saving $/GJ	Valuation PE Ratio
Estimated Share	$0.09	$0.14	$8.00	25.00	0.37	10.00
Prices from Model	$0.22	$0.27	$9.00	CTP Estimated Cost of Production	NGP N2 Removal Tariff	CTP Shares Issued
	$0.35	$0.40	$10.00	$1.50	$0.72	705,697,647.00
Total Uncovered Tariff Site to Sydney city gate		$3.65		Post Reform Haulage Site to Sydney city gate	$4.69	

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Some of my notes as I try to come to grips with things

1.0 My own view of CTP's Strategic Plan

Having achieved positive cash flow from the 2 NT power station GSA's CTP has successfully raised the finance (In conjunction with a 50% contribution from MAC on the Mereenie wells) to fund the 4 well Appraisal drilling program which has the potential to establish certified 2P net to Central reserves of 352.9-541.4 PJ.

This increased reserve certification is expected to pave the way for CTP to raise finance for additional drilling and supportive gas processing infrastructure both to supply approx.10TJ/day needed to meet the Pine Creek and Owen Springs power station GSA's as well as an additional 50% share of Mereenie production of 60TJ/day to sell gas to use all of the available NGP capacity in late 2018.

Since profits will primarily come from the gas that they supply to the East Coast Market, CTP's primary focus is to have their 30 TJ/day of gas ready to deliver to East Coast Client/s.

Sydney city gate is the target market (Price).

1.01 Can CTP Deliver this Strategy Successfully?

- ✓ Positive Indication
- Risk
- Information
- Idea

1.01.01 What Prospect is there of moderate Success resulting from the 4 Well Horizontal Drilling Appraisal Program?

✓ First Up the 2017 Q3 Report Page 2 "Testing of the Stairway Sandstone at Mereenie from the previously drilled West Mereenie 15 continues free flowing gas at sustainable rates (Previously stated to be 1.1 TJ/Day) with a low nitrogen content of 2.6%. **Additional recompletion opportunities have been identified**." This at least means we look like getting some gas from the existing (NW Mereenie?) wells.

✓ Given the considerable body analysis that has been undertaken here is a reasonable chance that the current 4 well Appraisal drilling program (Across Mereenie, Palm Valley and Ooraminna) will result in the certification of additional reserves which combined with Central's existing total 2P Reserves of 125.9 PJ would give total potential 2P Reserves, net to Central, of between 352.9 – 541.4 PJ

✓ A successful horizontal drilling program would increase the confidence that Mereenie should sustain a production rate of say 60 TJ/day (30 TJ/day net to CTP).

2017 Q4 P8 shows a concept for the well design. I appreciate the information which is well worth reading and should generate some shareholder confidence but how about tell us which well pads are being used to drill?

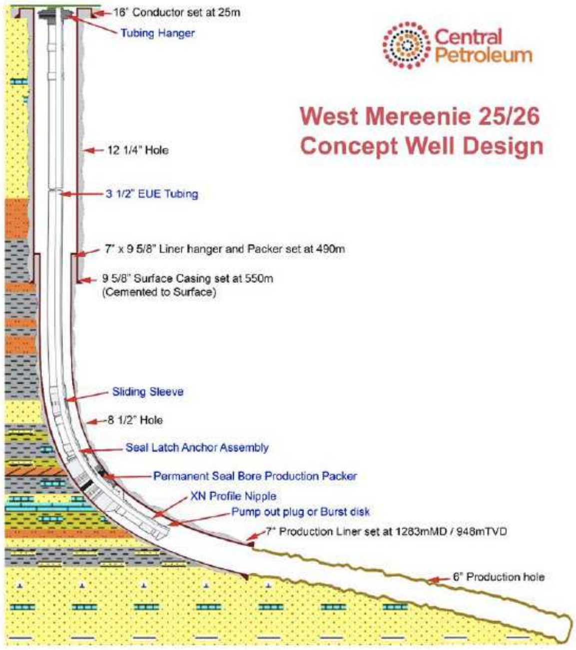
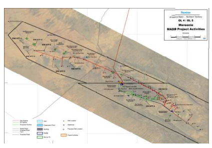


Figure 4: West Mereenie 25/26 Concept Well Design

Whilst there is a fair degree of optimism that the horizontal drilling initiative will be successful CTP have emphasised that there are no guarantees.

NW Mereenie has already been drilled as part of the Santos MADD (Mereenie Appraisal and Development Drilling) project undertaken during 2013. Fair enough!
This link to the Environmental plan has a pretty good map of NW Mereenie and even shows the borrow pits Etc.

https://dpir.nt.gov.au/__data/assets/pdf_file/0007/258694/SantosMereenieAppraisalDevelopmentDrilling.pdf



2017 Q1 Report Additional recompletion opportunities have been identified. They probably will perform in a similar fashion to WM 15 but every little bit helps.

Here is the link to its WCR (Well Completion Report for West Mereenie 15 which contains quite a lot of information and original flow rates.

http://www.geoscience.nt.gov.au/gemis/ntgsjspui/bitstream/1/84350/1/WM15_WellCompletionReport.pdf

Extract from WM15 WCR

(e)   Testing

There was one drillstem test conducted at West Mereenie 15. The interval 1332m to 1351m was straddle tested after wireline log acquisition utilising inflatable packers. This test resulted in a stabilised gas flow to surface measured at 1.26 MMCFD through a ½" choke. Details are included as Appendix IV. In addition 7 open hole flow tests were run as summarised in the table below and in Appendix IV.

Interesting to note the DST came in at roughly 1.32 TJ/day.

I should be able to get my hands on the WCR's for the other NW Mereenie wells (Public Information) so I will be very interested to find out the location of the 2 wells they select for the Mereenie Appraisal Program.
Example

http://geoscience.nt.gov.au/gemis/ntgsjspui/bitstream/1/86500/1/WM19_Well_Completion_Report.pdf

- It looks like they are going to be new wells started on the drill pads of existing wells which presumably makes them easier to connect to the gathering pipework.

- My understanding is that past drilling operations in this area that have successfully intersected natural fractures have shown high sustainable gas flows for considerable periods and this looks promising.

- Apparently horizontal drilling at Palm Valley that intersected a natural fracture gave spectacular results until it was fracked and the propping agent acted to constrict the flow. hearsay perhaps but promising.

What Risks were Identified in the SOA Document in relation to the Lower Stairway Development?

- Development of the Lower Stairway resources is forecast to start in FY 2019 in order to maximise througput into the NGP. This timeline is however very aggressive and could easily slip by 12 months or more.

- In addition, little or no production impact has been forecast by the operator during the installation of new plant and equipment. While it may be possible that annual quantities remain relatively consistant, it is likely that some impact on production would occur during the installation of new equipment. If the NGP is delayed then it is likely that this will impact on the ability of Central's Gas to reach these markets.

- Decommissioning and abandonment of Mereenie 2P resource Development Scope is estimated at $80M.

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1.02 What do the SOA & CTP Reports say about the Horizontal Drilling Appraisal Project?

As it turns out quite a lot:-

As outlined in the SOA the appraisal and associated reserve certification, funding and execution of drilling/infrastructure works will require a very aggressive schedule to be ready for first NGP gas late 2018.

- If CTP does not fill the pipe from day 1 it is money down the drain not monetisation down the pipe.

There appears to be a difference between the 2017 AGM Webinar comments:

"*We anticipate that over time we will be spending more money on the processing facilities but it will not be a critical path to us selling it (Gas) there is existing present 50 TJ/day existing capacity at Mereenie and 22 TJ/day existing capacity at Palm Valley hence 50 + 20 = 70 (TJ/Day)….*"

and the SOA document, which appears to express a different view.

If the full scope of the Mereenie Surface facilities upgrade shown in the SOA to Increase production to 50 TJ/Day will be needed to process enough gas to utilise the (Presently) available 60TJ/day to achieve the start-up NGP capacity.

If the full scope shown on P226 of the SOA was needed there may be a significant risk that it would not be commission in time leading to be a slow ramp up of processing capability to achieve full 60TJ/Day NGP capacity. This would manifest itself in reduced profit to CTP with a consequent impact on share value.

Table 4-4: Future Mereenie 2P development scope and capital cost

Development scope	Cost (A$ million)
Facility works to allow 30 TJ/d gas production	17
Re-use existing crestal wells EM43/EM12/EM2	0.1
Re-complete WM19/WM15/WM14/WM16 as gas producers	5.5
Drill and complete two new gas production wells and EM44 top hole	9.5
Other	0.5
Total development capital	**32.6**

Facility scope includes:

- restaging of compressors K-201 and K-202;
- installation of integrated control system;
- upgrade of PLCs, safety shutdown, SCADA and individual control systems to enable better reliability at higher production rates;
- installation of a more effective produced water management system; and
- installation of export metering and plant air.

In view of comments made at the AGM webinar P10 it looks like a major refinancing exercise will be done in say 12 months after the reserve base is known.

"it appears to me that if you are going to even think about refinancing when you've got in the next 6-12 months a totally new reserve base Etc. ….."

This is a pretty important risk which is under CTP's ownership so I think shareholders need a very clear explanation the scope and mechanism for funding, of any facilities upgrades that are needed to process the first NGP gas quota.

Shareholder sentiment needs to be maintained especially during the next 12 months. An unrealistically low share price is an open invitation to corporate predators (I have one particular organisation in mind) and even an unsuccessful attempt has the potential to disrupt execution the NGP first gas strategy.

The question at the AGM webinar about future information flow headings was a really good one. The following preliminary list of information flow headings mentioned at the webinar needs to be refined and expanded.

- Regulatory approval for the drilling
- Drilling Contractor Appointed
- Joint venture approvals,
- Spudding of wells
- Outcome of the AEMC enquiry,
- Outcome of the GMRG enquiry by December
- Outcome of the Pepper Enquiry in December

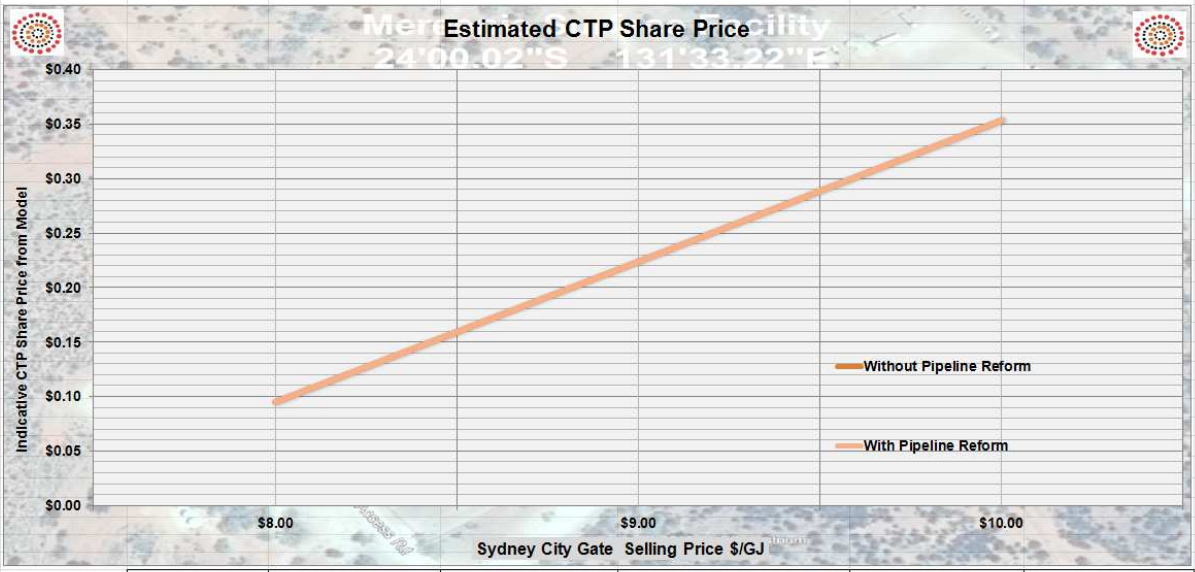
Early identification of a detailed information flow scope is fundamental maintaining shareholder sentiment through an effective communication plan because it prevents unproductive suspicion and speculation. "If it hasn't been announced jet then it hasn't happened".

The detailed IFH schedule will also provide shareholders with an insight into the milestones that Central is targeting over the next 12 months.

The present estimated **cost of (Mereenie) production** following the 2P horizontal drilling reserve development should be under \$1.50 (See SOA P226 extract (\$2.64 at 15TJ/day and S1.11 at 50 TJ/day) and the same document shows "Worst Case" haulage of **\$5.20/GJ** to Wallumbilla, giving us a worst case delivered cost of **\$ 6.70/GJ** (Including **\$0.70** for N_2 removal).

✓ Q1 Report P2 "The pipeline reforms, aimed at putting downward pressure on transportation costs, should start to emerge next year and our expectation is that the all up transportation costs of delivering our gas to Sydney city gate should be significantly lower than the reference rates currently offered. With brownfield production costs for new supply from our existing operating assets, we could (subject to pipeline tariff reform) have a total break-even cost structure of around **\$5/GJ** delivered at Sydney city gate".

The sensitivity model base Case **without** pipeline tariff reform on uncovered pipes and the input parameters listed at the bottom of the graph indicates a share price in the vicinity of 22C.



Graph Parameters	Without Pipeline Reform	With Pipeline Reform	Wallumbilla Selling Price	NGP Profitable Gas Sales TJ/Day	Pipeline Reform Saving $/GJ	Valuation PE Ratio
Estimated Share	$0.09	$0.09	$8.00	25.00	0.00	10.00
Prices from Model	$0.22	$0.22	$9.00	CTP Estimated Cost of Production	NGP N2 Removal Tariff	CTP Shares Issued
	$0.35	$0.35	$10.00	$1.50	$0.72	705,697,647.00
Total Uncovered Tariff Site to Sydney city gate	$3.65			Post Reform Haulage Site to Sydney city gate	$5.05	

Taking a plausible price of $9.00/GJ point of sale price at Sydney city gate with no pipeline reform:-

Probable Sydney City Gate Sale Price Estimate

		CTP Cost of Production Ex Field	**$1.50**			
		NGP N2 Removal	**$0.72**			
		NGP Gas Pipeline Tariff	$1.40			
		Amadeus Pipeline To Tennant Creek	0.60	APA		
		Carpenteria Mount Isa to Ballera	1.62	APA	Subject to Uncovered	
		South West Queensland Ballera to Moomba	0.40	APA	Reform	
		Moomba to Sydney Inc.Throughput Charge $0.05	1.03	APA	$3.65	
		Total Haulage to Sydney City Gate Excl. N2 Removal	$ 5.05			
		Selling Price	**$9.00**			
		Profit/GJ NGP Gas	**$1.73**			
TJ/Day	TJ/PA		$/PA	P/E Ratio	PE X Profit	
25.00	9,125		**$15,786,250**	**10.00**	**$**	**157,862,500**
				CTP Shares Issued		**705,697,647**
				Estimated Share Price	$	0.22

✓ The following snapshot indicates that CTP has an unregulated break even cost of supplying gas to Sydney City Gate of $7.27 and with a 25% reduction in tariffs for unregulated pipelines this would be $6.36.

Unregulated CSG Break Even Delivered to Sydney city gate

CSG Cost Of Production Ex Site	$	5.70
Wallumbilla to Moomba		1.16
Moomba to Sydney Inc.Throughput Charge $0.05		1.32
Estimate Gasfiels to Wallumbilla		1.50
CSG Haulage to Sydney Citygate	$	3.98
CSG Unregulated Cost Delivered to Sydney	**$**	**9.68**

Regulated CSG Break Even Delivered to Sydney city gate

CSG Cost Of Production Ex Site	$	5.70
Wallumbilla toMoomba		1.16
Moomba to Sydney Inc.Throughput Charge $0.05		1.32
Estimate Gasfiels to Wallumbilla		1.50
Uncovered CSG Haulage to Sydney Citygate	$	3.98
Pipeline Reform Saving	$	1.00
CSG Regulated Cost Delivered to Sydney	**$**	**8.69**

Unregulated CTP Break Even Delivered to Sydney city gate

Cost Of Production at Sitegate	**$**	**1.50**	
NGP N2 Removal		$0.72	
Published Unregulated Haulage To Sydney Citygate	$	3.65	
NGP Haulage	$	1.40	
Unregulated Haulage Site to Sydney Incl. NGP no N2 Removal	**$**	**5.05**	**Unegulated CSG-CTP Cost Difference**
CTP Unregulated Cost Delivered to Sydney Citygate	**$**	**7.27**	**$ 2.41**

Regulated CTP Break Even Delivered to Sydney city gate

Cost Of Production at Sitegate	**$**	**1.50**	
NGP N2 Removal		$0.72	
Published Unregulated Haulage To Sydney Citygate	$	3.65	
NGP Haulage	$	1.40	
Pipeline Reform Saving	$	0.91	
Regulated Haulage Site to Sydney Incl. NGP no N2 Removal	**$**	**4.14**	**Regulated CSG-CTP Cost Difference**
CTP Regulated Cost Delivered to Sydney	**$**	**6.36**	**$ 2.33**

✓ It looks like CTP have a cost advantage over CSG producers of about $2.00 which interestingly enough is relatively insensitive to pipeline the impact pf pipeline reform..

	Regulated	Unregulated

Unregulated CSG Break Even Delivered to Sydney city gate

CSG Cost Of Production Ex Site	$ 5.70	
Wallumbilla to Moomba	1.16	
Moomba to Sydney Inc. Throughput Charge $0.05	$1.03	
Estimate Haulage Gasfiels to Wallumbilla	1.50	
CSG Haulage to Sydney Citygate	$ 3.69	
CSG Unregulated Cost Delivered to Sydney	$ 9.39	

Regulated CSG Break Even Delivered to Sydney city gate

CSG Cost Of Production Ex Site	$ 5.70	
Wallumbilla toMoomba	1.16	
Moomba to Sydney Inc. Throughput Charge $0.05	$1.03	
Estimate Haulage Gasfiels to Wallumbilla	1.50	
Uncovered CSG Haulage to Sydney Citygate	$ 3.69	
Pipeline Reform Saving	$ -	
CSG Regulated Cost Delivered to Sydney	$ 9.39	

Unregulated CTP Break Even Delivered to Sydney city gate

Cost Of Production at Sitegate	$ 1.50	
NGP N2 Removal	$ 0.72	
Published Unregulated Haulage To Sydney Citygate	$ 3.65	
NGP Haulage	$1.40	
Unregulated Haulage Site to Sydney Incl. NGP no N2 Removal	$ 5.05	Unegulated CSG-CTP Cost Difference
CTP Unregulated Cost Delivered to Sydney Citygate	$ 7.27	$ 2.12

Regulated CTP Break Even Delivered to Sydney city gate

Cost Of Production at Sitegate	$ 1.50	
NGP N2 Removal	$0.72	
Published Unregulated Haulage To Sydney Citygate	$ 3.65	
NGP Haulage	$1.40	
Pipeline Reform Saving	$ -	
Regulated Haulage Site to Sydney Incl. NGP no N2 Removal	$ 5.05	Regulated CSG-CTP Cost Difference
CTP Regulated Cost Delivered to Sydney	$ 7.27	$ 2.12

From the AGM webinar, “The ACCC report says the marginal cost of CSG will be around about **$5.70** ex-field and then they have to transport it **which would make CTP one of the lowest cost producers**.”

True but we have the longest pipeline to market and don’t forget that CSG producers will benefit from pipeline reform as well but the cost advantage is still good news for CTP as the CSG producers are likely to have a significant influence on the market price.

Richard made a direct comment to me at a Sydney presentation words to the effect that “Selling the gas is not a problem”, and my research comes up with the same conclusion.

With this in mind I can understand why CTP not in a rush to enter into East Coast GSA’s, and is holding out for the best possible deal for shareholders.

As you can see from the graph above a 1 Dollar differences in the whole supply chain or selling price makes quite a bit of difference to the modelled share price depending on market sentiment Etc.

The Second Supplementary Booklet however, paints a more pessimistic picture on P11 “The GMRG design recommendations reduce the likelihood that any potential future reductions in pipeline tariffs will be as significant as the reductions advocated by Central.” It is worth reading this section carefully as a background when taking into account the current state of gas haulage regulation to gain a balanced view.

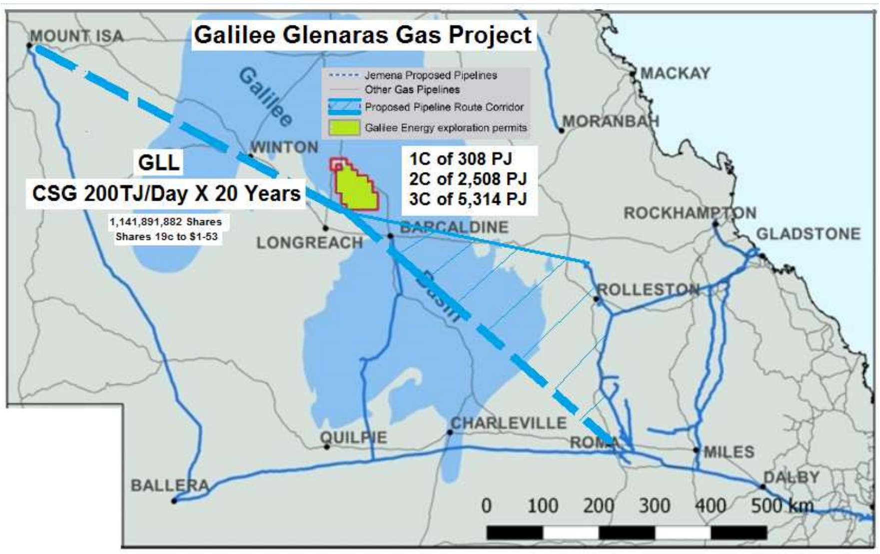
In any case CTP has the most to gain or lose here as they are much further than their competition from East Coast markets. This probably explains why Blacktip gas has found its way to Phosphate Hill but no further South which has fortunately left 60 TJ/Day still available in the NGP for CTP and MAC to share.

We appear to have a baseline underlying profitability as long as we find the reserves and fine tune our (Cost of Production) end and from then we just have to put in the hard yards to build on it.

If someone else beats CTP to filling that pipe we have a real problem that will not sort itself out until the NGP/Carpentaria pipeline capacity is increased in at about 2022 when the Eastern Extension of the NGP is presently targeted for commissioning.

Snapshot of the Glenaras Gas Project driving the FEED being currently undertaken by Jemena which indicates that just like the NGP was at this stage FID is increasingly probable:-

FYI here is a snapshot from the montage on the Glenaras project which is the driver behind the current Jemena FEED initiative.



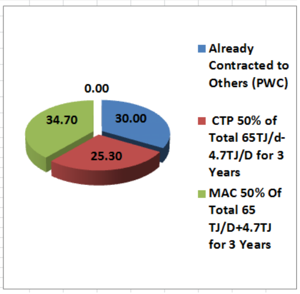
- Given the current status of the 4 well appraisal program I would like see an announcement from CTP to the effect that they have at least first right of refusal from APA on their NGP gas haulage or a pretty good explanation as to why not ?

✓ Based on Ex field CSG cost of $5.70, I was a bit surprised when I did this model using a 25% covered pipeline haulage discount.
Our competitive cost advantage over CSG appears to remain the same at just over $ 2.00 and is not that sensitive to pipeline reform.
This will vary of course and as the CSG fields mature and they have to drill step out wells in less productive areas, deal with pump maintenance and the dreaded P&A budget which usually goes only one way our relatively constant "Horizontal Drilling" extraction will hopefully work increasingly in our favour.

If CTP are required to supply gas to service the Macquarie 10M prepaid GPSA then until the Amadeus/NGP/Carpentaria delivery chain is upgraded Central would be restricted to East Coast Gas Sales of 25.3 TJ/day for at least 3 years after the NGP is commissioned unless CTP comes to an alternative arrangement with MAC to in accordance with the Prepaid contract with MAC.

NGP "Pipefull" Without Compression at 90 TJ/Day

	TJ/Day	PJ/Year
NGP uncompressed Compressed Capacity	90.00	
Already Contracted to Others (PWC)	30.00	10.95
CTP 50% of Total 65TJ/d-4.7TJ/D for 3 Years	25.30	9.23
MAC 50% Of Total 65 TJ/D+4.7TJ for 3 Years	34.70	12.67
Available Spare Capacity	0.00	0.00
		32.85



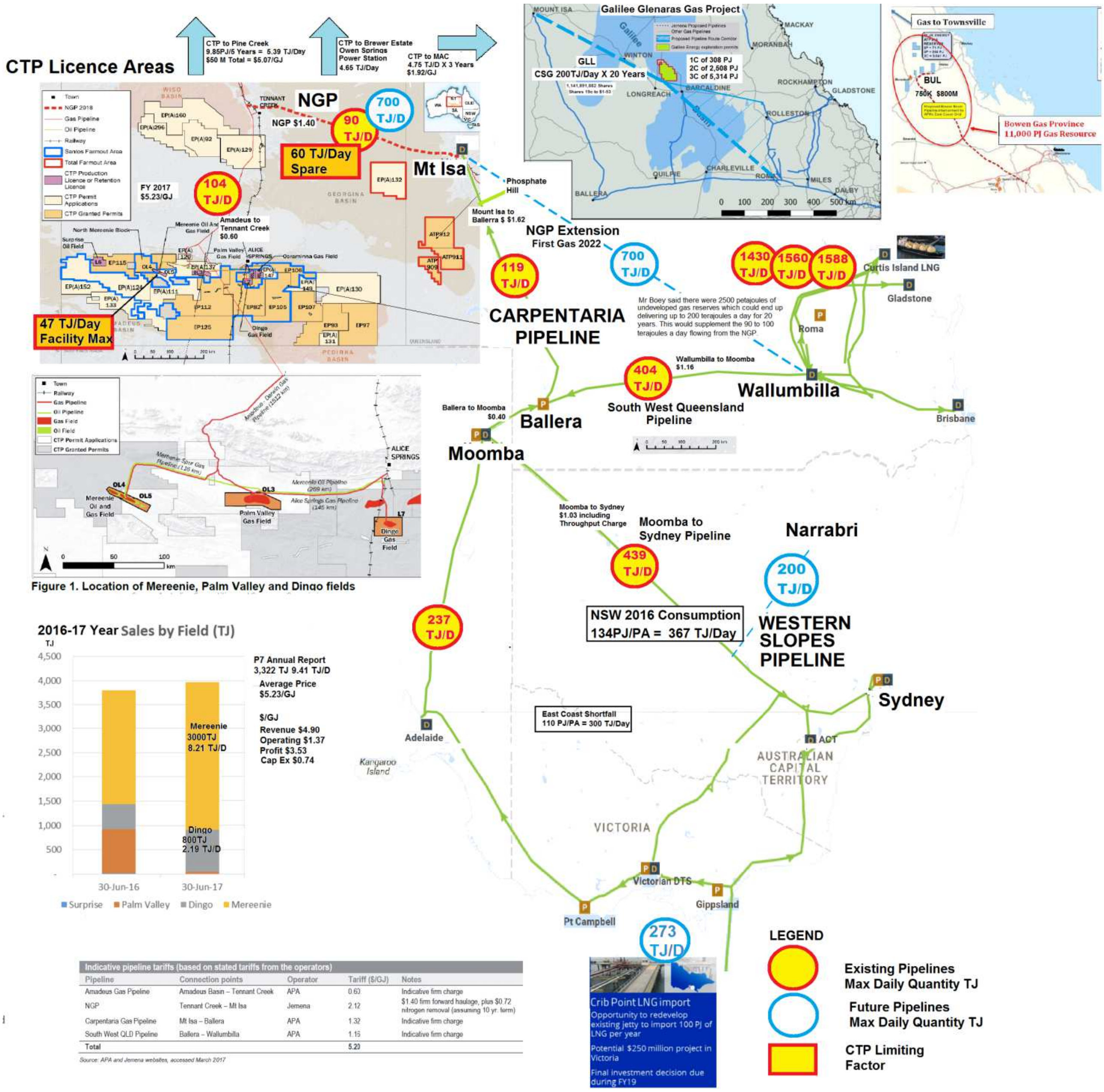
2.00 NGP and NGP Extension Update

Put simply, my understanding is that the NGP capacity is likely to remain at 90-100 TJ/Day for at least 3 years after NGP first gas.

The risk of the NGP not being ready for first gas at end 2018 is very low.

The Incitec Pivot ASX announcement below indicates that the Remaining 30 TJ/day of NGP capacity will be taken up until at least 30 June 2028.

In any case it's not much good upgrading the NGP capacity without a similar upgrade to the upstream and downstream pipelines so CTP needs to focus on a base case of 60 TJ/day spare NGP capacity in the medium term future.



Indicative pipeline tariffs (based on stated tariffs from the operators)

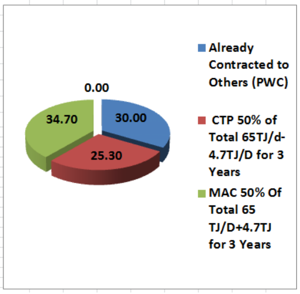
Pipeline	Connection points	Operator	Tariff ($/GJ)	Notes
Amadeus Gas Pipeline	Amadeus Basin – Tennant Creek	APA	0.60	Indicative firm charge
NGP	Tennant Creek – Mt Isa	Jemena	2.12	$1.40 firm forward haulage, plus $0.72 nitrogen removal (assuming 10 yr. term)
Carpentaria Gas Pipeline	Mt Isa – Ballera	APA	1.32	Indicative firm charge
South West QLD Pipeline	Ballera – Wallumbilla	APA	1.16	Indicative firm charge
Total			5.20	

Source: APA and Jemena websites, accessed March 2017

- FYI Incitec Pivot 30 TJ/Day supply agreement extends through to 2028 and ties up NGP capacity..

NGP "Pipefull" Without Compression at 90 TJ/Day

	TJ/Day	PJ/Year
NGP uncompressed Compressed Capacity	90.00	
Already Contracted to Others (PWC)	30.00	10.95
CTP 50% of Total 65TJ/d-4.7TJ/D for 3 Years	25.30	9.23
MAC 50% Of Total 65 TJ/D+4.7TJ for 3 Years	34.70	12.67
Available Spare Capacity	0.00	0.00
		32.85



http://www.asx.com.au/asxpdf/20151117/pdf/4331qrwkm0n05v.pdf

For the record, it was a pity that the CTP announcement that it had entered into a non-binding heads of agreement (HOA) to supply up to 15PJ pa of gas from its conventional reservoirs in the Northern Territory to Incitec Pivot Limited did not result in business.

http://www.abnnewswire.net/press/en/78632/Central-Petroleum-Limited-(ASX-CTP)-Enters-Framework-Agreement-with-Incitec-Pivot-78632.html

- I was not impressed at the time that when the PWC stole this one from under CTP's nose that its shareholders were not at least informed. The absurdity of the whole thing is that our EDL GSA molecules will probably go straight round the corner at Tennant Creek and end up at Phosphate hill. I hope we get a discount if we feed low N_2 gas into the Amadeus pipeline.

- To increase capacity from 90TJ/day to 160 TJ/day the NGP needs to add a midline compressor station which is not in the start-up scope. It is my guess that the commissioning of additional NGP capacity will be timed to coincide with the NGP extension to be ready in 2022.

https://jemena.com.au/about/newsroom/media-release/2017/jemena-fast-tracks-plans-to-connect-galilee-basin-

http://www.couriermail.com.au/business/jemena-and-galilee-energy-strike-deal-to-fasttrack-gas-pipeline/news-story/dc93f948abe2b7799733a1332344449d

- Jemena's Mr Boey explained that "by undertaking the early planning works, both Jemena and Galilee Energy will be ready to proceed to front end engineering and design (FEED) on both pipeline and field development in 2019 with the objective of first gas to market in 2022."

- The extension of the NGP pipeline will reduce viability of Carpentaria Pipeline upgrade leaving CTP restricted to 60 TJ/day until the extended Jemena pipeline provides a path for the increased NGP capacity.

- I noted the comment with interest from Jemena's Mr Boey mentioning 200 TJ/day from Galilee's Glenaras project and the 90-100 TJ/day NGP flow which makes me think Jemena won't increase the NGP capacity until there they have firm commitments to fill the pipe.

- The NGP extension will probably be able to ultimately handle on the order of 700TJ/day.

Revision 4 07/12/18 Issued as a Preliminary Draft

3.00 Information on the Mereenie Field Development Program contained in the SOA and 2016 Annual Report

http://centralpetroleum.com.au/wp-content/uploads/2015/09/CTP-2016-Annual-Report_FINAL.pdf

2016 Annual Report 21/09/16

Reference P14 2016 Annual Report P4

Mereenie Field Development program was optimised to maximise reserve upgrades and reduce costs. The savings realised through these efficiency gains will be used to further develop the Company's knowledge of the Stairway and P4 formations. The Reserve Upgrade Program comprises three stages:

- Stage 1 – Consisted of reviewing all existing data from Mereenie including nearly 60 wells already drilled and selected wire-line pressure and flow testing at Mereenie and the building and history matching of a static and dynamic model of the gas reservoir at Mereenie. **This was completed at a cost of $4 million.**

- Stage 2 – Subject to joint venture approval consists of refining and optimising of Stage 1, including possible production testing. This should increase further the reserves available for contracting. In addition, production results at Dingo will be incorporated.

- Stage 3 – Subject to joint venture approval will consist of appraisal drilling and production testing on the Stairway Formation generally with a target of doubling the Stage 2 reserves at Mereenie. Successful completion of the Stage 3 reserves plus reserve upgrades at Palm Valley and Dingo would result in future sales to Central (including deliveries under existing contracts) of around 250 PJ.

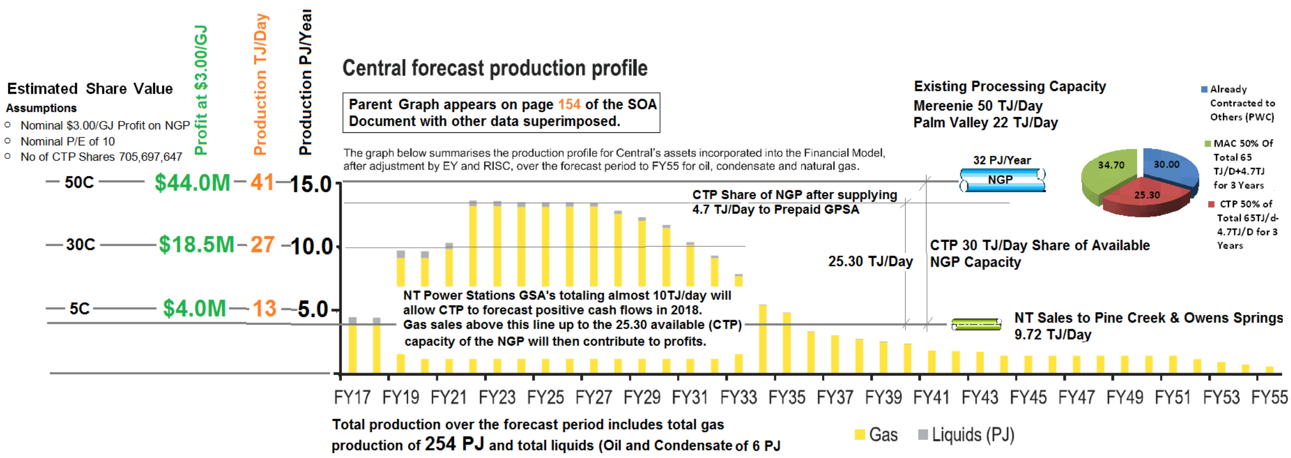
    - By 21/09/16 we had spent 4 million dollars on well engineering in relation to Mereenie exploration.

A simplified model of CTP's future business after the NGP is commissioned.

The SOA P226 describes the lower stairway resource development and I am hoping that it was taken into the weighted Central forecast production profile used to produce the montage below.

Clearly this model has inherent inaccuracies and makes a number of broad assumptions.

(You can hold down the Ctrl key & use the mouse wheel to zoom in or out)



The parent graph used to build the montage appears on page 154 of the SOA documentation on P154 with and vertical scales added for:-

- Production in TJ/Day,
- Profit at nominal $3.00/GJ for gas exported down the NGP
- Estimated share value based on a PE of 10 applied to $3.00 on sales above the 9.72 TJ/day (Say 10TJ/day) sales to NT power stations which appears to be CTP's break-even point.

The line through the lower green Pipeline represents gas sold to NT markets which does not take up capacity in the NGP and the distance between the Green and Blue pipe lines represents CTP's 50% share of the present available capacity of the NGP path to East Coast gas Markets.

CTP's share of available NGP capacity will be reduced by 4.7 TJ/day for 3 years after the NGP is commissioned because it will probably be taken up with supplying gas to MAC to satisfy the prepaid GPSA.

This represents a 15% drop in available capacity but since the gas was sold to MAC at about $2/GJ probably representing only a $0.50 profit/GJ when compared with normal sales at say $3.00/TJ profit used in these calculations. Effectively this reduces CTP's initial earning capacity by say $2.6M/PA for 3 Years.

In the event that CTP are unable to supply the full 25.30 TJ/day to the NGP the % loss in earnings would be proportionally increased.

It is interesting to compare the total gas production in the SOA model of **254PJ** with the reserve certification target in the Entitlement Offer Information Booklet P17 which, if successful, targets total potential 2P net to Central reserves of **352.9-541.4** reserves.

		No. of Wells	Gross Potential	Net to Central
1	Mereenie Stairway	2	110 – 186	55 – 92.5[1]
2	Palm Valley Shallow	1	83 – 165	83 – 165[2]
3	Ooraminna	1	89 – 158	89 – 158[3]
	TOTAL 2P	**4**	**282 – 509**	**227 – 415.5[4]**
	Existing Total Reserves			125.9[5]
	TOTAL POTENTIAL 2P CENTRAL RESERVES			**352.9 – 541.4**

RISC Production Forecast for Mereenie from SOA P221

The RISC model indicates that the 2C Mereenie production through to 2030 is 50 TJ/day. The 2C production ties in with the apparent Mereenie Processing Capacity of 50 TJ/day.

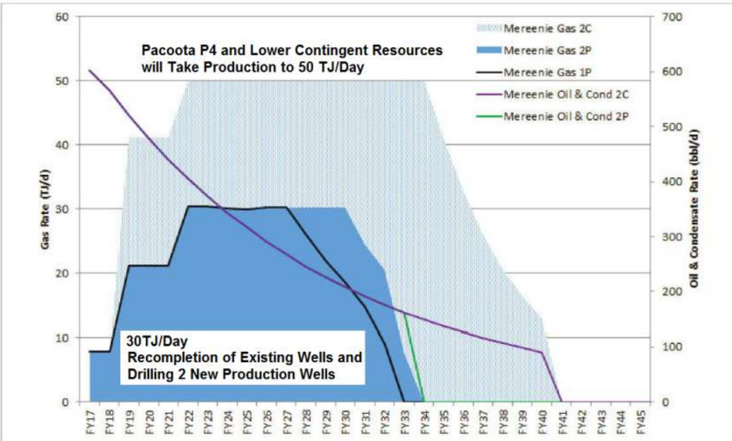


Figure 4-2: Mereenie Gross Gas and Liquids Production Forecasts

What is the Scope of the Lower Stairway Contingent Resource Development documented in the SOA?

I am still not comfortable that CTP will need to get their hands on quite a bit of money to bring the Mereenie surface facilities up to enough capacity in time for NGP first gas.

Since as was mentioned at the AGM Webinar CTP will probably wait at least 12 months to refinance I wonder where this money will come from.

Straight out of the SOA at P226

Table 4-5: Lower Stairway contingent resource development scope and capital cost (gross)

Development scope	Cost (A$ million)
Facility works to allow 50 TJ/d gas production	68
48 Lower Stairway development wells	144
Other	0.5
Total development capital for contingent resources	**213**
Three additional development wells targeting 2P resource acceleration	*9.0*

Should the successful development of the lower stairway resources occur, it is also estimated that 3 additional wells are drilled to target the acceleration of 2P gas reserves.

Central's original development concept calls for the Lower Stairway Wells to be slim hole design to enable the utilisation of smaller low cost rigs as the wells are shallow at less than 1000m depth.

However recent work by Central has indicated the potential to drill high angle wells drilled underbalanced and/or with air oriented to maximise the intersection with natural fractures.

In this scenario laterals are anticipated to be in the order of 500-700m requiring a two well proof of concept well program prior to development.

How many more wells will be needed?

The high angle well option has the potential to significantly reduce the well count to reduce the well count to in the order of 20 albeit more expensive wells.

If pursued, this option could potentially reduce capital costs by approx. $50 million.

What is the scope of works needed to upgrade the Mereenie Facilities to 50 TJ/Day?

The facility estimate is preliminary in nature and has been prepared with little engineering definition.

The facility scope rewired to increase production to 50 TJ/day is:

- Two new field boost compressors at 2.5 MW each
- Two new Export Compressirs at 1 MW Each.
- Slug Catcher Installation
- Additional Infield pipelines and flowlines.
- Installation of integrated control system
- Upgrade of PLC,s safety shutdown, SCADA, and individual control systems to allow better reliability at higher production rates.
- Installation of a more effective produced water management system.
- Installation of export metering and plant air.

What range of production costs can we expect from the new facility?

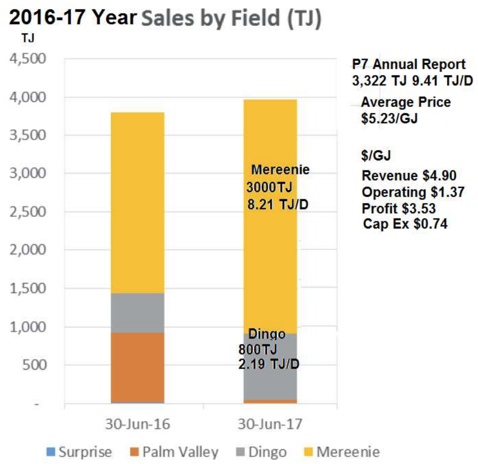
SOA P226 It is estimated that operating costs increase from 14.5M in 2017 when production rates are approx 15TJ/Day (Had not signed EDL GSA for 9.85PJ of gas over five years IE. 5.39TJ/Day) to $20.3M/PA as production increases to 50 TJ/D.

Rough calculations on the above:

- **15TJ/day => $14.5M/5.475M GJ = $2.64/GJ operating Cost**
- **50TJ/day => $20.3M/18.25M GJ = $1.11/GJ operating Cost**

I found that trying to work out CTP's Cost of Production and average selling price for gas is at best a crude exercise because CTP seems to avoid making it clear in their reporting.
The following is my attempt for 2016-17.

This information is really important to help shareholders make investment decisions in relation to the Company.



Other Risks are there to the CTP Operation?

- **Sustainable Flow Rates and related profits**

  CTP would need to explain any variance between the current expected production profile forecast when compared with that shown on P154 of the SOA document which shows gas production peaking at under 40 TJ/day.

At a nominal $3/GJ profit and sales of 40 TJ/day would indicate a maximum annual profit of somewhere near $30M/year taking into account that about 10TJ/day represents the present break eaven point. Undiluted from its present 705,697,647 shares on a P/E 0f 10 at about 40C/Share. Clearly this is very sensitive to production costs of sustainable flow rates gas haulage tariffs and selling price Etc.

- **Delivery Pipeline Capacity**

Presently this (EY and RISC Adjusted) model above indicates that the available 60 TJ capacity of the NGP will probably be adequate for another 5-6 years (2022) but would require increased NGP capacity after that date. Refer to Montage.

- **Failure to produce 40 TJ/day (30NGP +10 NT) to take advantage of 60TJ/day initial NGP Capacity late 2018**

Drilling Approvals covered by NT Schedule of onshore petroleum exploration and production requirements 2016. P25 covers approval application not less than 1 month before drilling.

https://nt.gov.au/__data/assets/pdf_file/0004/295906/schedule-of-petroleum-onshore-requirements-2016.pdf

Already Febuary has been mentioned as the start date for drilling (Mereenie).

From Webinar… Basically you will have an IP (Initial Production) as soon as you drill' and have the 90 day flow rates (90 days later) which will let you know whether your model is grossly accurate or grossly inaccurate and 180 is when you start the reserve certification process.

If reserve certification is a necessary prerequiste to funding of additional wells and infrastructure to produce CTP's share of the 60TJ/day spare NGP startup capacity then the comment in the SOA seems justified.

"Development of the Lower Stairway resources is forecast to start in FY 2019 in order to maximise througput into the NGP. This timeline is however very aggressive and could easily slip by 12 months or more."

- **Impact of Macquarie pre-paid gas sales agreement (GSPA)**

As announced on 26 April 2017 Central entered into a Gas Sales agreement "GSA" with EDL NGD (NT) Pty Ltd ("EDL") with gas deliveries commencing 1 June 2017.

In May 2016 Central announced it had entered into a 5.2PJ pre-paid gas sales agreement "GSPA" with Macquarie Bank Limited "MBL", repayment of which will commence following commissioning of the Northern Gas Pipeline anticipated in late 2018.

Under the GSPA, MBL has a quarterly option to take a financial settlement in lieu of taking the physical delivery of the gas. The amount payable by Central, should MBL opt for a financial settlement, is dependent on the **actual price received under any new GSA's supplied from the agreed production areas.** Where there are no new GSA's or the quantity delivered under new GSA's is less than the GSPA volumes, a floor financial settlement amount would be payable. The economic consequences of the EDL GSTA was disclosed in the First Supplementary Scheme Booklet. As a consequence, Central is required under AASB 139 to adjust the carrying amount of the financial liability in line with the sales price negotiated under the EDL contract, net of any additional gas transportation costs. As the price paid by EDL under the GSA, net of transportation costs, exceeds the floor financial settlement price, the impact of the adjustment will be an expense to current year profit and loss of $9.49 million which reflects the total increase in potential financial liability over the life of the GSPA. It is important to note that the expense to be recorded for the 2016/17 financial year is a non-cash accounting adjustment. Additionally, this accounting treatment will record a liability reflecting the full expected amount to be paid out should MBL opt for a financial settlement in lieu of taking physical delivery of gas which would appear to be the conservative accounting treatment. It is also important to note that Accounting Standards do not allow Central to recognise any future assets associated with the revenue expected to be received under the EDL contract which triggers the increase in value of the GSPA financial liability. In this regard, Central's future accounting periods' profit and loss figures will include recognition of revenue under the EDL contract not currently recognised as an asset in the accounts for the 2016/17 financial year. In addition, where MBL elect for physical delivery of gas under the GSPA, the recorded financial liability will unwind resulting in an increase in accounting revenue for that period.

  - **SOA P171**

Notes the minimum capital expenditure required to increase production to levels required to meaningfuly access the East Cast gas market is estimated to be approx $40,6M…..

9.3.1.4 Removal of exposure to near-term capital expenditure requirements

In order for Central to realise the value in its asset portfolio, the company requires further capital expenditure. Based on the Capex profiles reviewed by RISC, the minimum capital expenditure required to increase production to levels required to meaningfully access the East Coast gas market is estimated to be approximately $40.6 million for Mereenie, Palm Valley and Dingo. This does not include any further work on the expansion projects; Palm Valley Deep, Stairway or Ooraminna.

- Ooraminna gas will cost money for basic surface facilities and pipeline to Dingo & if processed at Brewer estate will be subject to CTP pipeline capacity to the estate of 5.36 TJ/Day.

- **SOA 242 Ooraminna Commitment Well**
  This differs from comments made at the AGM Webinar which indiced that the wells would be treated as a package. This is important enough to be covered by a separate "Newsflow" announcement.

  "Central has a 100% interest in Retention Licences 3 and 4 which has a Commitment Well which must be drilled by 6 March next year (see page 242 of Scheme Booklet for Ooraminna's prospectivity) for which capital will need to be raised. This timeframe has already been deferred from the original deadline. Given the east coast gas shortage and the imminent commissioning of the NGP with spare capacity there is a clear risk that another deferral of this commitment would not be granted again by the NT Government. To avoid the commitment Central could hand back the licences with adverse consequences to the value of Central"

- **GRR Contingent Liability**
  I appreciate that there may be some legal issues here but every effort should be made to keep shareholders up to date.

9.3.1.5 Removal of exposure to contingent liabilities

As set out in section 4.2.4, Central is currently in a legal dispute with GRR. Any payment is contingent on the outcome of this legal dispute, which has been running for some time. There is currently no certainty whether or not Central will ultimately have to pay any of the disputed amount, or any other costs. Further, there is no certainty as to the potential timing of any payment. Central denies liability for the claim and is defending its position. Central has taken the view that there is no basis to record a financial liability in relation to this matter, and therefore no liability has been recorded on Central's audited balance sheet.

Given the uncertainty, and management's expectations with regard to potential payment, we have not included any potential liability in our valuation of Central. However, there is still a risk that Central will be ordered by the court to make some payment in regard to this dispute. If the Proposed Scheme is approved and implemented, Central Shareholders will no longer have any exposure to this potential future liability.