Characteristics of the Gidgealpa Group Composite Resource Play in the Cooper Basin, South Australia

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Presentation Outline

1. The “Composite Resource Play”
   a) Where?
   b) What?

2. Evidence for Composite Gas Resource Accumulations

3. Analysis of Historic Conventional Gas Production
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3. Analysis of Historic Conventional Gas Production
Cooper Basin Location

- First commercial gas discovered in 1963.
- Has produced over 5 tcf of gas.
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The Composite Resource Play

Unconventional Gas in the Gidgealpa Group:

- Shale Gas
- Tight Sands
- Deep Coal Seams

“Composite Gas Resource Accumulation”
Mesaverde Group, Piceance Basin analogue for Gidgealpa Group, Cooper Basin

- Basin-centred gas accumulations previously limited to sandstone reservoirs (Cumella et al, 2008).
- Gas production from fracture stimulated mudstones and coals indicates that a range of lithologies can contribute to gas production from desiccated, gas saturated intervals.
- The term “Composite gas resource accumulation” is used to capture the range of potential reservoir lithologies within the gas saturated zone.
Composite Resource Play Fairway

Figure sourced from Beach Energy
Coal and carbonaceous shale of the Patchawarra Formation are the principal source rocks of the Cooper Basin, in terms of richness, quality and thickness.
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Gas Saturated Gidgealpa Group

Nappamerri Trough

EVIDENCE (Hillis et al, 2001)

- High resistivity of the Gidgealpa Group (>20Ωm over large intervals);
- Tests recovered gas with no water; and
- Overpressure

High resistivities in the Permian succession of the Nappamerri Trough suggest gas saturation (from Hillis et al, 2001).
Patchawarra Formation Overpressure

Patchawarra Formation pressure gradient data derived from DSTs and other data sources. Water pressure gradient is 0.43 psi/ft. Gradients exceeding ~0.45 psi/ft are indicative of overpressured gas. Overpressured gas in the Patchawarra Formation occurs at depths exceeding ~9500’ (~2900m).

Base Patchawarra Depth Structure Map showing Coonatie and Moomba gas fields and selected wells.
Average Porosity and Permeability of Patchawarra Reservoirs

Average Porosity (left) and Permeability (right) of Patchawarra Formation, Cooper Basin (Heath, 1989)

POROSITY < 9% in the deeper troughs

PERMEABILITY <0.1mD in the deeper troughs
“REM” Shale – Not self sourcing shale play

HI’s < 200 for range of maturities indicates TYPE III organic matter
Migrated gas stored in REM shale?

- **Interparticle and intraparticle** pores associated with **detrital illite** and other minerals may be important and these pores could be interconnected.

- **Intra-organopores** are rare (consistent with dominance of Type III organic material).
- **Inter-organopores** along the interface with detrital minerals provide 1-2% nanoporosity and could be significant where organic matter concentrates in muddy laminae.

3503.5m: Typical area of clays (lighter grey – dominated by muscovite/illite), quartz (medium grey), siderite (white) and organic matter (black). Photo shows elongate nature of micropores along cleavage traces in the muscovite/illite. Back scattered electron photomicrograph.

3503.5m: 3384.50m: Nanopores (arrows) at junctions between mineral matter (light grey) and organic matter (dark grey). Secondary electron photomicrograph after dual beam focussed ion beam milling.

*Encounter 1 REM Core Petrology Study - Dr S E Phillips, PGPC in Encounter 1 WCR*
Deep Coal Gas

Paning 2: Single 63,000 pound proppant fracture stimulation in Toolachee coal seam (~2900m) – Short term production test flowed gas (no water) at up to 90,000 scf/d, flared continuously over four days.

Deep Coal Gas

GIDGEALPA GROUP COALS

- Enormous generative potential.
- Very high gas contents where thermally mature.

Bindah 3 Patchawarra Formation VC50 Coal - Just in wet gas generation window. Large remaining generation potential.

High gas contents indicated by high mud gas readings when drilling through thermally mature coal seams.
Cooper Coals

HIGH INERTINITE CONTENT MEANS ABUNDANT PRESERVED MACROPOROSITY

- Inertinite coal maceral group derived from charred and biochemically altered plant cell wall material.
- Inertinite is more or less non-reactive during carbonization. Liptinite and vitrinite melt with the evolution of volatiles, inertinite generally remains intact.
- SEM work on VC50 coal from Bindah 3 has shown that the coals contain significant macroporosity (>50nm).
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Moomba Gas Field

- Discovered 1966.
- Large volume, conventionally trapped gas field.
- Has produced > 1 tcf gas, mostly from the Toolachee and Daralingie formations.
- Located on margin of Nappamerri Trough.
Moomba Central Decline Curve Analysis
Moomba Central Decline Curve Analysis

- Extended period of low rate decline has best fit \( b \)-factor between 0.5 – 1.0
- More typical of shale or tight gas production.
- Fetkovic et al. (1996) – “low-permeability, stimulated wells’ production performance can appear similar to layered, no-crossflow reservoir response”.
- **Strong evidence** to suggest that gas production from this field has been supplemented by tight lithologies and possibly coal seams.

MOOMBA CENTRAL
Production predominantly from the Toolachee and Daralingie formations above the deeper continuous gas accumulation.
Moomba North Main and North West
Top of Nappamerri Trough Continuous Gas Accumulation?

Moomba North West:
>14 bcf gas, no water, produced from Patchawarra Formation

Moomba North Main:

MOOMBA 86:
2.6 BCF gas produced from the Epsilon Formation – NO WATER

MOOMBA 134:
5.2 BCF gas produced from the Epsilon Formation – NO WATER
Moomba North Main “Sweet Spot” – Epsilon Formation Shoreface Sands

Moomba 134
Conclusions

• Unique unconventional resource play in the deep troughs of the Cooper Basin.
• Evidence suggests tight sands, mudstones and deep coals will contribute to future gas production – the accumulations are here described as **Composite Gas Resource accumulations**.
• Initial unconventional resource estimates for the Cooper Basin are high:
  • Early stage 2C contingent unconventional gas resources total 4.6 TCF
  • EIA estimates a risked recoverable amount of 79.9 TCF dry gas
• Exploration and appraisal phase ramping up.
Thank you