Note for File

Vic/P42 Prospect Inventory from interpretation of GBA02B 3D Seismic Survey

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Introduction

The prospects identified by BSOC over the GBA02B 3D survey acquired in 2002 in Vic/P42 are summarised in this note for file below (this does not include prospects and leads identified previously and falling outside of the 3D area). The location of the area with 3D survey locations and identified prospects and leads is shown on the attached Figure 1. A description of each prospect is given below and their volumetric prospect appraisal summarised.

ZaneGrey North

ZaneGrey North is a faulted anticline updip of Nannygai-1 drilled in 1972 (see Enclosure 1). The anticline appears to be formed by a major basin forming normal fault striking NW-SE through the northeastern graticular block of Vic/P42. Nannygai-1 was drilled in 1972 on a TWT structure beneath a 'high velocity' submarine canyon. This well had an interpreted low relief closure at Top Latrobe level, valid in time.

Current depth conversion work, albeit equivocal, suggests Nannygai-1 may have drilled on the northern closure limit at intra-Latrobe Group levels. Interpreted spill points are mapped northeast of Nannygai-1 and east of ZaneGrey North, although both these areas are beyond the limit of good data quality in the BSOC 3D, and over the Kingfish 3D dataset. Good hydrocarbon shows were encountered in sandstone over the interval 2898 - 2914m in Kingfish Formation *L. balmei* zone sediments. Log analysis interpreted some 6m of live oil in the interval 2898 - 2904m (Phillips 1994). This is argued to demonstrate structural closure.

The acquisition of the GBA02B 3D survey in 2002 over the area has recognised a significant updip component to Nannygai-1 at the level of the interpreted pay zone and at deeper and shallower horizons in both time and depth. Detailed velocity information through the high velocity submarine canyon sequence has been derived from advanced geophysical processing techniques, although a significant depth conversion risk remains. A minor laterally discontinuous normal fault is identified at intra-Latrobe Group levels downthrowing the Nannygai-1 area close to the well location, from a significant area updip (in TWT and depth) to the southwest. This, and the interpreted closure at the level of the pay zone, augurs well for this being updip and within depth closure at intra Kingfish and Volador formation levels. The deeper Roundhead Member forms a primary objective. A smaller areal anticlinal closure at Top Latrobe Group forms a secondary objective.

Regional correlation across the southern Gippsland Basin has identified that a prospective sequence of reservoir seal pairs remains untested (by Nannygai-1) updip in ZaneGrey North for the Kingfish Formation and within deeper undrilled sequences of the Kingfish and Volador formations, and within deep Golden Beach Subgroup deposits (the latter correlated over long distance with Archer-1 and Anemone-1 wells to the southeast).

Reservoirs

The Kingfish and Volador formations form the primary reservoir objectives in the prospect, in particular thick sandstones of the Roundhead and Grunter members. In the nearby Kingfish Oil Field, Kingfish Formation reservoirs are a sequence of sandstones deposited in lower and upper shoreface settings with minor marine shale interbeds. Reservoir quality is expected to be excellent with average porosities around 20% and permeabilities of several Darcies. Deeper porosities decline due to compaction although porosities of over 25% can remain even at depths of 3000m. A similar unit to the Grunter Member is encountered in Gurnard-1 and forms a high net to gross sandstone, approximately 28m thick, overlying the Kate Shale. In the Volador Formation, the Roundhead Member was encountered in Gurnard-1 and Roundhead-1 and is expected to form a massive sandstone unit approximately 42m thick. Numerous other sandstone reservoirs, subordinate to these identified targets are expected to occur throughout the sequence.

Seals

Top seals are likely to be provided (in a stacked pay) by back barrier lagoonal and interdistributary shales becoming more prevalent deeper in the sequence (possibly from Nannygai pay zone level and deeper). The Kingfish Formation becomes more distal to the palaeoshoreline with depth at this location and the potential for developing laterally extensive lower coastal plain shales exists. This is interpreted to augur well for intraformational sealing.

A top seal is also likely to be provided by shales of the Lakes Entrance Formation. Seat seal may separate the Gurnard and Kingfish formations and any hydrocarbon fill (as was the case in Kingfish). This may generate lateral sealing within stratigraphically trapped Gurnard Formation reservoirs (as was the case in Kingfish between P1.1 and M1.2 reservoirs). An eastwards truncation of the upper part of the Kingfish Formation strata leads to the potential for 'rim' plays, with top seal from Gurnard Formation shales and lateral seals from intraformational marine shales of the Kingfish Formation.

Whilst ZaneGrey North is predominantly a faulted anticlinal closure, lateral fault seal on the major basin forming fault to its southwest may also enhance structural closure, albeit with a higher risk. Lateral juxtaposition of high net to gross sequences in this downthrown block, with lower net to gross sequences of the deeper Volador Formation in the ZaneGrey South fault block, augur well for any cross fault seal. Clay smear potential was determined for Nannygai-1 and indicates that below 2550m CSP values are in excess of a likely sealing threshold of 45 (for fault throws of over 30m).

Source Rocks

Non-marine coastal plain organic rich mudstones and coals represent the source rocks for both oil and gas in the basin. These are dominantly of terrestrial plant origin and widely distributed throughout the Latrobe Group. Gas and oil mature source rocks for the ZaneGrey North Prospect are interpreted to occur in the Central Deep to the northeast. Potential oil mature source rocks are interpreted within the Latrobe Group Halibut Subgroup immediately to the northeast, which is interpreted to have provided an oil charge to the undersaturated giant Kingfish Oil Field. Charge is expected to originate directly from the northeast, or via spill from the Kingfish Field through the saddle to the east.

A gas mature kitchen is mapped at the top Golden Beach level immediately to the northeast of ZaneGrey, however the lack of gas within Kingfish suggests that vertical migration may not be occurring. Gas is present at the top Latrobe in Bream to the west, although this structure is much shallower than ZaneGrey and unlikely to be a conduit for gas migration. Simplicity would suggest that, as ZaneGrey is between a gas and oil field, and an oil field, then it might be expected that any hydrocarbons encountered would be “oil with some gas”.

Any oil encountered in ZaneGrey is likely to have properties comparable with Bream and Kingfish. The Bream oil is described as a paraffinic crude with 45°API density and a pour point of 60°F. Kingfish oil has 47° API and a pour point of 60°F. The Bream oil is saturated at reservoir conditions and is in contact with a large, low CO_2 gas cap. No indication of H_2S is identified in nearby wells.

Risks

The main risks for the ZaneGrey North Prospect relate to the mapped depth closure and hence the depth conversion. A strong lateral velocity variation in the overburden makes the depth conversion problematic and the single greatest geological risk. Detailed seismic velocity data and analysis have been used to minimise the risk, and structural closure is considered to be greater than depth uncertainty. Whilst depth closure is a high risk, there is also significant upside in the

mapped spill to the east and northeast. Intraformational sealing and breaching by minor faulting is a secondary risk.

ZaneGrey South

ZaneGrey South is an upthrown fault block closure (see Enclosure 2). Gurnard-1 drilled the structure in 1969 to test a large top Latrobe fault dependent closure, beneath a Miocene submarine canyon. Depth conversion is complicated by the high velocity fill in the Miocene submarine canyon and associated pull-up effect. Sophisticated 'image-ray' depth conversion suggests it remains a fault block structure at the Kingfish Formation level and upper Volador Formation (sequences penetrated). Gurnard Formation was penetrated in the well with a thickness of 27 m with an apparent, although questionable, mud gas kick at the top of the sequence. The reason for failure of the well is still equivocal, although it is considered that there is no cross fault seal with the ZaneGrey North fault block to the northeast of the well. Regional correlation indicates that the upper Kingfish Formation is proximal to the palaeoshoreline at this location and the potential for laterally and vertically extensive shales is inadequate. The Kingfish and upper Volador formations penetrated in Gurnard-1 are juxtaposed with upper Kingfish and Gurnard formation deposits in the downthrown fault block to the north, hence fault closure is considered invalid. The gas kick in the Gurnard Formation may be explained by the likely cross fault juxtaposition of Lakes Entrance Formation for the uppermost part of the sequence. Two formation interval tests were run within sediments of the Kingfish Formation (*F. Longus* zone); the first at 2944m recovered formation water and contamination; the second at 2924m encountered pale yellow fluorescence and a hydrocarbon odour. There may be minor fault closed pay zones in the vicinity of the well at this latter level.

Minor updip potential is identified at the Top Latrobe level and within units penetrated by Gurnard-1, although the greatest potential is envisaged in the sequences unpenetrated by Gurnard-1 where better top and fault seals are interpreted.

The structure is formed by a major basin forming normal fault striking NW-SE through the northeastern graticular block of Vic/P42. An interpreted spill point is mapped to the southeast into the area south of Kingfish.

The acquisition of 3D seismic in 2002 by BSOC over the area has recognised a significant closure beneath Gurnard-1 at the deeper Volador Formation and the Golden Beach Subgroup levels in both time and depth. Detailed velocity information through the high velocity submarine canyon sequence has been derived from advanced geophysical processing techniques, although a significant depth conversion risk remains.

Regional correlation across the southern Gippsland Basin has identified that a potentially prospective sequence of reservoir seal pairs remains untested (by Gurnard-1) in ZaneGrey South for the deeper undrilled sequences of the Volador Formation and within deep Golden Beach Subgroup deposits (the latter correlated over long distance with Archer-1 and Anemone-1 wells to the southeast).

<u>Reservoirs</u>

The Volador Formation forms the primary reservoir objectives in the prospect. Whilst the Roundhead Member was encountered near TD in Gurnard-1, significant sandstone reservoirs are known to occur deeper in this formation regionally. Reservoir quality is expected to be excellent with average porosities around 16% and good permeabilities. Deeper porosities decline due to compaction although porosities of over 25% can remain even at depths of 3000m. The Golden Beach Subgroup forms a secondary objective, although the prognosed depth and expected sequence for this unit are difficult to predict. The nearest correlation is at Melville-1 10km to the south, although the sequence there was present on the Southern Terrace and very much

condensed. It is expected that a comparable sequence to that penetrated in the Archer-1 and Anemone-1 wells would be encountered in ZaneGrey South. In Anemone-1A unusually high porosities are observed in marine sandstones of the Golden Beach Subgroup. Average porosities of 15% or greater exist down to 4500m.

Seals

Top seals are likely to be provided (in a stacked pay) by back barrier lagoonal and interdistributary shales of the lower Volador Formation becoming more prevalent deeper in the sequence. Lateral fault seal on the major basin forming fault to its northeast is expected to be enhanced with depth as the more shaly deeper Volador Formation deposits become fault juxtaposed in the downthrown block (at approximately 3000m subsea in the upthrown block). Extensive marine shale seals are predicted in the objective sequence at ZaneGrey South, by analogy along trend from Archer-1.

Archer-1 is significant in that a total of 17 stacked oil and gas pay zones were penetrated through the lower Halibut and Golden Beach subgroups in the well, often separated by these marine shale units. The well was also significant in showing that pay zones have column heights in excess of dip closure. At the level of the S2 marine shale (top Campanian) of the Golden Beach Sub-group, an additional fault dependent closure is interpreted.

Source Rocks

Non-marine coastal plain organic rich mudstones and coals represent the source rocks for both oil and gas in the basin. These are dominantly of terrestrial plant origin and widely distributed throughout the Latrobe Group. Gas and oil mature source rocks for the ZaneGrey South Prospect are interpreted to occur in the Central Deep to the northeast. Potential oil mature source rocks are interpreted within the Halibut Subgroup immediately to the northeast, which is interpreted to have provided an oil charge to the undersaturated giant Kingfish oil Field. Charge is expected to originate directly from the northeast.

A gas mature kitchen is mapped at the top Golden Beach level immediately to the northeast of ZaneGrey, however the lack of gas within Kingfish suggests that vertical migration may not be occurring. Gas is know at the top Latrobe in Bream to the west, although this structure is much shallower than ZaneGrey and unlikely to be a conduit for gas migration. Simplicity would suggest that, as ZaneGrey is between a gas and oil field, and an oil field, then it might be expected that any hydrocarbons encountered would be “oil with some gas”.

Any oil encountered in ZaneGrey is likely to have properties comparable with Bream and Kingfish. The Bream oil is described as a paraffinic crude with 45°API density and a pour point of 60°F. Kingfish oil has 47°API and a pour point of 60°F. The Bream oil is saturated at reservoir conditions and is in contact with a large, low CO_2 gas cap. No indication of H_2S is identified in nearby wells.

Risks

The main risks for the ZaneGrey South Prospect relate to lateral fault seal and the mapped depth closure and hence the depth conversion. Gurnard-1 is suggested to have demonstrated a lack of fault seal in the Kingfish Formation and the shallow Volador Formation sediments penetrated. However, at depth better seal potential (both top and lateral fault) is prognosed. A strong lateral velocity variation in the overburden makes the depth conversion problematic and another significant risk. Detailed seismic velocity data has been used to minimise this risk. The nature of the Golden Beach Subgroup and potential reservoir seal pairs has not been determined locally and constitutes a risk for this deeper play.

ZaneGrey (Edina Barrier Pinchout)

ZaneGrey (Edina Barrier Pinchout) is a faulted anticline and erosional truncation of barrier sandstones of the Kingfish Formation (see Enclosure 3), west of Gurnard-1 and Nannygai-1 (drilled in 1969 and 1972 respectively). The prospect has several similarities to the Fortescue Field to the northeast. Fortescue occurs where fluvial to barrier sandstones are stratigraphically trapped from the Halibut Field by erosional truncation at the Top Latrobe Group 'coarse clastics'. An 11.5m thick shale/coal unit provides seat seal.

Gurnard-1 was drilled in 1969 to test a large top Latrobe fault dependent closure, beneath a Miocene submarine canyon. Structure is valid in time, but in depth the structural closure is complex due to the high velocity fill in the Miocene submarine canyon and associated pull-up effect. Nannygai-1 was drilled in 1972 on a TWT structure beneath a 'high velocity' submarine canyon. This well had an interpreted low relief closure at Top Latrobe level, valid in time. Edina-1 was drilled in 1982 to test a small faulted anticline (3.4 km^2) mapped at the top Latrobe Group. The structure was considered to be due to compactional drape over an Eocene coastal barrier / deltaic sand reservoir sequence, now interpreted to be the 'Edina barrier'. The well was unsuccessful and reason for failure interpreted to be lack of fault seal.

The uppermost part of the Kingfish Formation (2333 to 2371m brt) is interpreted to be a barrier sand. A difference in salinity between this sand (33,000ppm) and sands below a shale unit at 2371 to 2380m (23,000ppm) suggests an active seat seal to this interval. This barrier sequence and deposits of the same age are interpreted to be absent in Gurnard-1 and Nannygai-1. Seismic interpretation on the GBA02B 3D has correlated the top of the Kingfish Formation between these three wells, and a coaly sequence immediately beneath the Edina Barrier. The potential for a rim play west of Gurnard-1 and Nannygai-1 has been identified from this seismic interpretation (the Edina Barrier Pinchout Prospect).

Reservoirs

The Kingfish Formation forms the primary reservoir objectives in the prospect, specifically the thick Edina Barrier sandstone identified in Edina-1. This barrier sequence has excellent reservoir properties in Edina-1, with porosities of 21-23%. In the nearby Kingfish Oil Field, Kingfish Formation reservoirs are a sequence of sandstones deposited in lower and upper shoreface settings with minor marine shale interbeds. Reservoir quality is expected to be excellent with average porosities around 20% and permeabilities of several Darcies.

Seals

Top seal is necessary within the Gurnard Formation for this rim play. Seat seal is required within back barrier lagoonal shales at the base of the Edina Barrier sequence (these occur in Edina-1, as indicated by salinity variations) or within coastal plain deposits interpreted to be truncated west of Gurnard-1 and Nannygai-1. A general eastwards truncation of the Kingfish Formation strata is evident on the 3D and leads to the potential for deeper 'rim' plays with seat seals within coastal plain deposits beneath this barrier bar and top seal from Gurnard Formation shales and lateral seals from intraformational shales of the Kingfish Formation.

Mapping of the 'zero edge' and the likely extent of the rim play are difficult. Two possible zero edges have been identified. An isopach map of the Edina Barrier sequence has been determined from the seismic and well data, using a “wedge” function for the gross thickness of the Top Latrobe to 53Mya event, and known thickness of the same sequence and Edina Barrier in Edina-1. This isopach is shown in Enclosure 3. In addition, a bright 'intra-Kingfish Formation event, subcropping west of Gurnard-1, is likely to represent coastal plain coaly deposits and this represents a possible seat seal unit beneath the barrier. The subcrop of this event, which constrains the eastern limit of the barrier, is also shown on the isopach in Enclosure 3.

Lateral seal presents a significant risk to the prospect. The barrier sequence is likely to have an erosional base that may breach the seat seal away from Edina-1. In addition, identification and mapping of potential seat seal units is problematic and subjective. Whilst the ZaneGrey Edina Barrier Subcrop is predominantly an anticlinal closure and rim play, faults evident around Gurnard-1 may breach seals and pose a further risk.

Source Rocks

Non-marine coastal plain organic rich mudstones and coals represent the source rocks for both oil and gas in the basin. These are dominantly of terrestrial plant origin and widely distributed throughout the Latrobe Group. Gas and oil mature source rocks for this prospect are interpreted to occur in the Central Deep to the northeast. Potential oil mature source rocks are interpreted within the Halibut Subgroup immediately to the northeast, which is interpreted to have provided an oil charge to the undersaturated giant Kingfish Oil Field. However, charge is unlikely to reach this prospect via spill from the Kingfish Field through the saddle to the east if an effective seat seal is present. Gas is present at the top Latrobe in Bream to the west, although this structure is much shallower and unlikely to be a conduit for gas migration. Charge may be accessible via migration from deeper Latrobe Group levels to the Central Deep. Simplicity would suggest that, as this prospect is between a gas and oil field, and an oil field, then it might be expected that any hydrocarbons encountered would be “oil with some gas”.

Any oil encountered is likely to have properties comparable with Bream and Kingfish. The Bream oil is described as a paraffinic crude with 45°API density and a pour point of 60°F. Kingfish oil has 47°API and a pour point of 60°F. The Bream oil is saturated at reservoir conditions and is in contact with a large, low CO_2 gas cap. No indication of H_2S is identified in nearby wells.

Risks

The main risks for the ZaneGrey Edina Barrier Subcrop Prospect relate to the seat seal and the mapped zero edge, and to a lesser extent, access to charge. Faulting and depth conversion pose additional risks. A strong lateral velocity variation in the overburden makes the depth conversion problematic. Detailed seismic velocity data has been used to minimise the risk.

Scope for Reserves

Reserves potential is poorly constrained at this time due to uncertainties in areal and vertical closure, resulting from uncertainty in zero edge limits and depth conversion.

Hemingway

Hemingway is a downthrown fault closure within sediments of the Latrobe Group identified on the GBA02B 3D seismic acquired in 2002 (see Enclosure 4). The fault strikes WNW-ESE. Fault displacement is evident from the top Latrobe Group and through the Golden Beach Subgroup. At the top Latrobe Group level the fault throw is minimal (less than 10m) and approaches sub-seismic resolution, although the displacement is clearly evident at seismic events within the deeper Latrobe Group sequence, and over 60m at the top Golden Beach Subgroup level. The vertical sequence within downthrown fault closure is approximately 600m, encompassing the Devilfish Sandstone Member and the prognosed condensed Golden Beach Subgroup sequence.

The juxtaposition of high net to gross sand prone sequences in the upthrown block indicates a significant fault seal risk. Some encouragement regarding a frequency attenuation that may represent gas bearing reservoir within the Devilfish Sandstone was identified and further advanced quantitative geophysical analyses were undertaken to identify if this was a 'DHI'. The results were encouraging, but no unequivocal DHI was found. In addition, the fault is on trend

with the Omeo Accumulation, which may have proven fault seal at the deeper Golden Beach level there.
Areal closure is significant within deposits of the Cobia Subgroup (the Devilfish Sandstone), although the deeper sequences have less extensive areal closures. Closure may also extend into the L8 licence to the east. Further mapping with the seismic data acquired there may extend the closure mapped in both vertical and areal sense.

Reservoirs

The entire Latrobe Group forms the primary reservoir objectives in the prospect, although it is likely to be incomplete on the Southern Terrace and comparable to the sequence penetrated in Melville-1 5km to the northeast. Excellent reservoirs are envisaged within sandstones of the Halibut and Cobia Subgroups. The Devilfish Sandstone, encountered in Pike-1 and Devilfish-1 to the southeast, was a massive (>120m) sequence of medium to coarse grained barrier sandstones with porosities of 20-30%. Deeper within the sequence the Kingfish Formation reservoirs form fine to medium grained back barrier /lagoonal to coastal barrier sandstones with porosities of 20-30%, but much lower net to gross ratios. The deeper *T longus* and Golden Beach Subgroup sediments are lithic, texturally immature sandstones with porosities averaging 15%. The Golden Beach Subgroup is expected to be thin or possibly absent, as only 45m of fluvial sediments were encountered in Melville-1 to the northeast, with net / gross of 68% and average porosity of 14%. Marginal reservoir potential is prognosed in Emperor Subgroup sandstones beneath the Golden Beach sediments. The 303 metres penetrated in Melville-1 had 5% net/gross with average porosity of 9%.

Seals

Top seals are likely to be provided (in a stacked pay) by back barrier lagoonal and interdistributary shales of the Latrobe Group. Top seal is also likely to be provided by shales of the Lakes Entrance Formation. Seat seal may separate the Gurnard and Kingfish formations and any hydrocarbon fill (as was the case in Kingfish). This may generate lateral sealing within stratigraphically trapped Gurnard Formation reservoirs (as was the case in Kingfish between P1.1 and M1.2 reservoirs). An eastwards truncation of the Kingfish Formation strata leads to the potential for 'rim' plays, with top seal from Gurnard Formation shales and lateral seals from intraformational marine shales of the Kingfish Formation. However, lateral fault seal is a significant risk due to the high net to gross of the sequences in the fault juxtaposed upthrown block. The Devilfish Sandstone is nearly 100% sands with thickness far in excess of fault throw. Lateral sealing would require clay smearing or development of a cataclasite zone, which suggests a very high lateral fault seal risk. Deeper in the sequence the lower net to gross suggests some fault seal potential is more likely, especially in the deeper Halibut and Golden Beach subgroup sequences, likely to be fault juxtaposed against Strzelecki or Emperor group sediments. This is suggested by the results of Omeo-1 to the northwest where hydrocarbons in the Golden Beach Subgroup reservoirs may be fault sealed laterally by deposits of the Strzelecki Group. Analysis of the clay smear potential in wells Gurnard-1, Nannygai-1 and Melville-1 suggests CSP over 45 (likely sealing) do not occur until deeper in the Kingfish Formation (lower *L. Balmei* palynozone) and into the Volador Formation. The thick marine Kate Shale, if present, is likely to be an effective top seal for the Roundhead Member play. Top Golden Beach volcanics, similar to those encountered in Melville-1, if present, are expected to be an effective top seal to any Golden Beach Subgroup reservoirs.

The fault throw in excess of 60m would suggest the Golden Beach Subgroup sediments, if present in Hemingway, would be juxtaposed against Strzelecki or Emperor groups, which augurs well for fault sealing.

Source Rocks

Non-marine coastal plain organic rich mudstones and coals represent the source rocks for both oil and gas in the basin. These are dominantly of terrestrial plant origin and widely distributed throughout the Latrobe Group. Gas and oil mature source rocks for the Hemingway Prospect are interpreted to occur in the Central Deep to the northeast and northwest. Potential oil mature source rocks are interpreted within the Latrobe Group Halibut Subgroup immediately to the northeast, which is interpreted to have provided an oil charge to the undersaturated giant Kingfish Oil Field. Gas mature charge is interpreted to the northwest beneath the Bream Oil and Gas Field. Migration distance to mature oil and gas charge is around 20km and is not considered a significant risk. Therefore, both gas and oil charge is predicted to occur in Hemingway.

Any oil encountered in Hemingway is likely to have properties comparable with Bream and Kingfish. The Bream oil is described as a paraffinic crude with 45° API density and a pour point of 60°F. Kingfish oil has 47°API and a pour point of 60°F. The Bream oil is saturated at reservoir conditions and is in contact with a large, low CO^2 gas cap. No indication of H_2S is identified in nearby wells.

Risks

The main risks for the Hemingway Prospect relate to the lateral fault seal. Attempts to identify a DHI to support the existence of fault seal have been only partially successful. The lack of an unequivocal DHI makes the lateral fault seal risk, at least for the high net to gross Devilfish Sandstone Member, a very high risk to the Hemingway Prospect. The lateral fault seal for the Golden Beach section is considered only a moderate risk and may be supported by the occurrence of gas along trend at Omeo-1.

Edina Deep

The Edina Deep Prospect is a faulted anticline beneath Edina-1 with an upside in upthrown fault closure, at the Volador Formation level (see Enclosure 5). At deeper Golden Beach Subgroup level it forms a tilted upthrown fault block closure. The structure appears to be formed through tilting and rollover above the major basin forming normal fault striking NW-SE to the immediate northeast, separating the shallower Terrace from the Central Deep. Edina-1 was drilled in 1982 to test a small faulted anticline mapped at the top Latrobe Group. The well did not penetrate deeper than the Kingfish Formation (Upper *L. balmei* palynozone) and no significant hydrocarbon shows were encountered. Current mapping indicates a top Latrobe vertical fault structural relief of approximately 30m at the well. Logs and cuttings indicate that excellent reservoirs occur in barrier bar sandstones of the upper Kingfish Formation. These are encountered beneath glauconitic sandstones and shales of the Gurnard Formation, with moderate porosity but very low permeability. The Kingfish Formation reservoirs form a high net to gross sequence and are unlikely to be laterally fault sealed against Gurnard Formation (and Kingfish Formation) reservoirs in the downthrown block immediately northeast. The lack of any accumulation in Gurnard Formation sandstones may be due to a lack of fault seal in calcareous sandstones of the 'Early Oligocene Wedge'. Potential is seen in the deeper and lower net to gross sequence of the Volador Formation (as encountered on trend in Melville-1), specifically the Roundhead Member and Kate Shale reservoir / seal pair. At the 'Nannygai Payzone seismic event' a culmination is mapped at 2750m with an interpreted spill point mapped to the Edina Deep faulted anticline at 2785m into further upthrown fault closure northeast of Edina-1, with additional closure before a saddle point to the southeast at 2820m.

The acquisition of the GBA02B 3D survey in 2002 over the area has delineated the structure and provides good definition. Detailed velocity information through the overburden has been derived

from advanced geophysical processing techniques, although a significant depth conversion risk remains.

Well correlation over 13km to the southeast at Melville-1 (in the same structural terrain) provides confidence that a prospective sequence of reservoir seal pairs remains untested (by Edina-1) within deeper undrilled sequences of the Kingfish and Volador formations, and Golden Beach Subgroup deposits.

Reservoirs

The Volador Formation forms the primary reservoir objectives in the prospect, in particular, thick sandstones of the Roundhead Member. In Melville-1, along trend, 56m of high net to gross sandstones were encountered beneath 32m of marine Kate Shale. Reservoir quality in this well was excellent with average porosities of 16.4% and good permeability. A similar unit to the Grunter Member is also anticipated by correlation with Melville-1. Golden Beach Subgroup reservoirs around 60m thick and 68% net to gross are also predicted to occur in a more fluvial facies with average porosity of 14%.

Seals

Top seals may be provided (in a stacked pay) by back barrier lagoonal and interdistributary shales becoming more prevalent deeper in the sequence. Analysis of the clay smear potential in wells Gurnard-1, Nannygai-1 and Melville-1 suggests CSP over 45 (likely sealing) do not occur until deeper in the Kingfish Formation (lower *L. balmei* palynozone) and into the Volador Formation. Regionally, the Kingfish Formation becomes more distal to the palaeoshoreline with depth at this location and the potential for developing laterally extensive lower coastal plain shales exists, which is interpreted to augur well for intraformational sealing.

The thick marine Kate Shale, if present is likely to be an effective top seal for the Roundhead Member play. Top Golden Beach volcanics, similar to those encountered in Melville-1, if present, are expected to be an effective top seal to Golden Beach Subgroup reservoirs. However, lateral fault seal will pose a significant risk for this prospect, especially to the northeast where high net to gross Kingfish Formation is interpreted in the downthrown block.

Source Rocks

Non-marine coastal plain organic rich mudstones and coals represent the source rocks for both oil and gas in the basin. These are dominantly of terrestrial plant origin and widely distributed throughout the Latrobe Group. Gas and oil mature source rocks for the Edina Deep Prospect are interpreted to occur in the Central Deep to the north and northeast. Potential oil mature source rocks are interpreted within the Latrobe Group Halibut Subgroup immediately to the northeast, which is interpreted to have provided an oil charge to the undersaturated giant Kingfish Oil Field. Gas mature charge is interpreted to the north beneath the Bream Oil and Gas Field. Therefore, both gas and oil charge may occur in Edina Deep.

Any oil encountered in Edina Deep is likely to have properties comparable with Bream and Kingfish. The Bream oil is described as a paraffinic crude with 45° API density and a pour point of 60° Fahrenheit. Kingfish oil has 47° API and a pour point of 60°. The Bream oil is saturated at reservoir conditions and is in contact with a large, low CO_2 gas cap. No indication of H_2S is identified in nearby wells.

Risks

The main risks for the Edina Deep Prospect relate to the mapped depth closure and hence the depth conversion, and the lateral fault seal. Velocity variation in the overburden makes the depth conversion problematic and a significant risk. The lateral fault seal and top seal are also

significant risks due to the reliance on fault closure. Whilst the Kate Shale, if present, would provide a good top seal, lateral fault seal remains a major risk. The presence of a sequence of volcanics as a top seal for the Golden Beach reservoirs also poses a large risk, as they may not occur here.

Prospect Appraisal

Introduction

The five prospects identified from mapping the GBA02B 3D survey have been appraised (with the exception of the Edina Barrier Pinchout Prospect) through stochastic modelling of the various geological variables used to determine the potential hydrocarbon volumes. For the prospects ZaneGrey North, ZaneGrey South, Hemingway and Edina Deep, estimates have been made of in-place and recoverable reserves of oil and gas and the relevant probability of success (POS) determined for each prospect. These are summarised in Table 1 below, ranked by expectation (the product of POS and mean success volume). Note that these are only the reserves for Vic/P42, as some of the prospects extend into permits to the east. The Edina Barrier Pinchout Prospect is considered too problematic to assess volumetrically at this time due to the significant uncertainties regarding the pinch-out edge of the barrier identified in Edina-1. The significant seat seal risk indicates it is not a preferred drilling candidate at this time.

Table 1 – Main prospect inventory

PROSPECT*	UNRISKED RESERVES (RECOVERABLE)		RISKED RESERVES (RECOVERABLE)						
			POS	MSV		P90	P50	P10	Expectation
	OIL MMb	GAS Bcf		OIL MMb	GAS Bcf	OIL MMb	OIL MMb	OIL MMb	OIL MMb
ZaneGrey North	134	0.0	34%	87.7	9.0	52.3	86.7	124.5	29.8
Hemingway	131.4	6.2	21%	54.6	4.5	3.2	53.0	104.8	11.5
Edina Deep	81.7	6.4	24%	40.2	6.7	14.6	40.3	66.7	9.6
ZaneGrey South	155.9	142.0	16%	57.1	47.7	12.1	53.3	106.7	9.1

* Ranked by expectation

Methodology

To handle uncertainty in the geological variables in the hydrocarbon reserves assessment, stochastic modelling was used. Monte Carlo simulation was used to replace point estimates of geological parameters with “fuzzy” values, reflecting their uncertainty. Dependencies between variables are carried through the assessment. The different ‘fuzzy’ variables are entered as probability distributions.

For the bulk rock volume (BRV) determinations the seismic interpretation of the various events are used. For the ZaneGrey area, the depth conversion is based on the most recent image-ray depth conversion. For Edina Deep and Hemingway depth conversion method used is a combination of this and the earlier 'layer-cake' Method 5, as these prospects fell mostly outside the area of interest for the image-ray depth conversion study and the area of the "high density velocity analysis". Spill points for the identified structural closures are entered for a range of points to account for the depth uncertainty and potential spill / leak points due to depth conversion, faulting etc. The likelihood of fault seal at different depth points is also determined from the clay smear potential (CSP) analysis to determine risk of leak points for each reservoir unit. Seal risk is addressed on a case-by-case basis for each reservoir / seal pair. Unfortunately, all cases are modelled independently for simplicity, whereas some dependency is expected. Thus results have most likely narrowed the range of potential reserves. Strong dependency would most likely lead to a predominance of low and high values, perhaps as a bimodal distribution.

Potential reservoir seal pairs are determined (where penetrated) from well correlation of penetrated sequences determined from the wells Nannygai-1, Gurnard-1, Melville-1 and Bream-5. Gas and oil cases are modelled by subjectively estimating the percentage column likely to be gas or oil filled for each reservoir unit, and ranging these as probability distributions.

Recovery factors and hydrocarbon saturations for the oil and gas legs of each reservoir unit are based on earlier publications from Esso Australia in their 1994 assessment of prospects over the Kingfish 3D survey area (Phillips, 1994), Rahmanian et al. (1990) and regional knowledge. They are ranged stochastically and individual cut-offs assigned for each reservoir. The cut-offs used are 1MMb and 5Bcf, i.e. where gross recoverable reserves for an individual modelled unit are less than these cut-offs the reserves do not contribute to the final net figure. Recovery factors for fields in the Gippsland Basin are high by comparison with global averages, due to good reservoirs and strong water drive. Examples of fields in the Gippsland Basin in Table 2 demonstrate these high recovery factors (Rahmanian *et al.*, 1990). Gas and oil expansion factors are estimated and ranged for the depths to each of the potential reservoirs.

Table 2 - Recovery Factors

Field	Reservoir	Oil RF%	Gas RF%
Flounder	Intra-Latrobe	55	70
Fortescue / Cobia /Halibut	Top Latrobe	67-71	-
Kingfish	Latrobe	68	-

An expanded description of the quantitative prospect appraisal is given below for each prospect. The Monte Carlo simulations are run using *Crystal Ball 2000* (an 'add-in' to *Excel*).

ZaneGrey North

The relevant depth converted seismic horizons used for the potential closure BRV determinations for ZaneGrey North are:

- Top Latrobe Group
- 53Mya (intra-Kingfish Formation) Seismic Event
- Nannygai Payzone Event
- Deep Latrobe Event

The BRV for the first two closures at Top Latrobe Group and the 53Mya Event are relatively small and as a result contribute less than 1% of the unrisked STOIIP potential for the prospect. The main reserves potential is derived from the deeper zones (this also relates to the reduced trap/seal risk for these deeper zones, not just the BRV). Some sixteen potential reservoir / seal pairs were used in the reserves determination, with many given high risks of seal failure

(therefore not contributing significantly to the risked reserves). Fourteen of these were identified from sequences penetrated in wells Nannygai-1, Gurnard-1 and Bream-5. Two hypothetical reservoir units were also modelled from the deeper Volador Formation sequence, which was not penetrated locally.

The areal and vertical closures mapped for the different horizons varies from insignificant at the 53Mya event to a minor 0.8km^2 and 10m at Top Latrobe level. The highest closure is mapped at the Nannygai Payzone event of 9.65km^2 and 70m (5.86km^2 in Vic/P42). The Golden Beach Subgroup is considered to be a viable target in this prospect, but it is expected to be at depth and reservoir quality and potential for intra-formational sealing potential unknown; hence it is not assessed as contributing to the reserves potential at this stage.

As the ZaneGrey North Prospect is considered to access the same kitchen area as the Kingfish (undersaturated) oil field, and it is clearly downdip of the Bream oil and gas field, a more 'oily' charge is modelled. Gas column, as a percentage, is modelled varying from 0-40% for shallower reservoir units and 0-100% for deeper reservoirs.

Risk factors for charge/timing, reservoir and trap are modelled as a single value for the prospect. The risks entered for these are 10%, 5% and 60% respectively. Seal risk is modelled on a reservoir unit case by case basis from a high of 70% (where high net to gross and lack of extensive shales suggest low sealing potential) to a low of 10% (where thick shale top seals occur and low net to gross gives CSP of greater than 45) depending on structural style, top seal quality and CSP for the unit.

The Monte Carlo simulation results give a probability of success (POS) of 34% of a mean success volume (MSV) of 180MMb (STOIIP), with a MSV of 88MMb (recoverable) and low middle and high recoverable oil reserve values (P90, P50 & P10) of 52, 87 and 125MMb. Potential associated gas mean success volumes are 30Bcf (GIIP) with only 9Bcf recoverable (the relatively low recoverable gas reserves relates to the lack of significant gas volumes in any single reservoir unit, and the lack of a completion on these relatively small individual volumes).

ZaneGrey South

The relevant depth converted seismic horizons used for the potential closure BRV determinations for ZaneGrey South are:

- Top Latrobe Group
- Deep Latrobe Event
- Top Golden Beach Subgroup

The Gurnard-1 well appears to be drilled close to the culmination of the Kingfish Formation levels, although a small subordinate four-way dip closure is mapped at Top Latrobe Group level 3.5km northwest of the well. The areal and vertical closure at this level is only 0.6km^2 and 5m and does not contribute to the net reserves for the base case, although a slightly more significant upside exists due to the uncertainty in the depth conversion at this level.

The fault closures mapped at Deep Latrobe level has an areal and vertical closure of 15.4km^2 and 120m and at Top Golden Beach level 17.2km^2 and 150m. At the Golden Beach level the horizon definition and well correlation are very poor due to poor data quality at this deep level and a lack of local well penetration of this sequence.

Six potential reservoir / seal pairs are modelled in the reserves determination, the first the 'coarse clastics' for the Top Latrobe level, the next three are Volador Formation sandstones penetrated in Bream-5 (the upper two were hydrocarbon bearing in this well) and the final two are hypothetical (and speculative) 40m Golden Beach Subgroup sandstones. Although there are no local penetrations of this latter sequence, it was considered consistent to consider at least 2

sequences with the results of the nearest occurrence in a similar setting in Archer-1 and Anemone-1 to the southeast in Vic/P45 (Archer-1 is significant in that a total of 17 stacked oil and gas pay zones were penetrated through the lower Latrobe and Golden Beach Sub-group in the well, separated by marine shale units).

The likely gas column proportions modelled for ZaneGrey South are similar to ZaneGrey North, with a range from 0-70% used (as it is likely to access the same Kingfish kitchen area). The slightly lower 'upside' gas proportion is used as it is effectively accessing charge through spillover from ZaneGrey North. Charge / timing risk is 10%, although a much higher reservoir risk of 25% is used (to address the lack of local penetrations of the modelled reservoir sequences). A trap risk of 75% reflects the depth conversion risk, the poorly constrained fault geometry of the structure and lack of success in the existing Gurnard-1 well. Seal risk is varied case-by-case, from a high of 70% to a low of 50%, reflecting the more problematic lateral fault seal for this prospect (also reflected in the higher trap risk of 75%). The 70% risks is used for the Golden Beach units where uncertainty on an effective top seal exists as well as the significant lateral fault seal risks. The 50% value is used for the lower net to gross Volador Formation reservoir units offset by large fault throws forming the structure with estimates of CSP over 45.

Simulation results give a POS of 16% of a MSV of 161MMb (STOIIP), with a MSV of 57MMb (recoverable) and low, middle and high recoverable oil reserve values (P90, P50 & P10) of 12, 53 and 107MMb. Potential associated gas mean success volumes are 81Bcf (GIIP) with 48Bcf recoverable.

Hemingway

The relevant horizons defining identified closures at Hemingway are:

- Top Kingfish Formation
- 53Mya (intra-Kingfish Formation) Seismic Event
- Nannygai Payzone Event
- Top Golden Beach Subgroup

Located 7km south west of the Melville-1 well, Hemingway is an untested downthrown fault closure along trend with the likely downthrown fault accumulation at Omeo. This mitigates the fault seal risk at least for the deeper Golden Beach reservoir levels.

Downthrown fault closure is mapped for all horizons. Closure extent is mapped to a spill point to the southeast in Vic/P42, although it is possibly constrained by data availability. Further areal and vertical closure may occur towards the southeast in L8 and Vic/P45. However, at shallower levels the fault throw is small and the fault discontinuous laterally. The areal and vertical closure varies from a high of 13.0km^2 and 160m at the Top Golden Beach level, to a low of 1.1km^2 and 25m at the 53Mya Event. At the shallower Kingfish Formation levels, fault throw is minor (5-20m) and the fault discontinuous towards the southeast in Vic/P42 making a significant structural risk especially at these shallower levels. At the deeper Golden Beach level fault throw varies around 50-100m across the structure.

The anticipated reservoir section was penetrated 7km northeast of the prospect at Melville-1, thus the reservoir / seal sections and volumetric parameters are well defined. Six potential reservoir / seal pairs are modelled for the reserves determination, all identified from the Melville-1 well. The first is the 'coarse clastics' unit of the Kingfish Formation near the top of the Latrobe Group, top sealed by Gurnard Formation shales and defined by the top Kingfish Formation Event. The second is a massive Kingfish Formation sandstone at the 53Mya Event level, sealed by a 20m shale section. The third is the Grunter Member equivalent and the fourth the Roundhead Member. For the BRV determination the Nannygai payzone Event defines both these. The fourth reservoir seal unit is a deep Volador Formation sandstone located just above the Golden Beach Subgroup in Melville-1, thus this is defined (assuming phantoming) from the Golden Beach

seismic event. The sixth reservoir unit modelled is the entire Golden Beach clastic sequence identified in Melville-1 and sealed by volcanics at its top, although there is a small risk that this unit may subcrop between the well and the prospect location.

The likely gas columns entered for Hemingway are varied from 0-60% for all levels, reflecting the likely access of the prospect to charge from the Central Deep, but in a more distal location on the Terrace and predominantly from the Kingfish kitchen area. The charge / timing risk is the highest of all four prospects at 20% to reflect its more distal location. Reservoir risk is 30% which is considered realistic for the riskier Golden Beach and Volador 'condensed' section that contribute for 90% of unrisked STOIIP potential. The trap risk of 60% reflects the nature of the dip closure along strike and the discontinuous nature of the fault required for closure. The seal risk is varied from a low of 50% for the Golden Beach level (due to the analogies to the Omeo Accumulation and better cross fault sealing envisaged) to a high of 80% for the 'coarse clastics' (where cross fault juxtapositioning of high on high net to gross sequence is envisaged).

Simulation results give a POS of 21% of a MSV of 115MMb (STOIIP), with an MSV of 55MMb (recoverable) and low, middle and high recoverable oil reserves (P90, P50 & P10) of 3, 53 and 105MMb. Potential associated gas mean success volumes are 11Bcf (GIIP) with 5Bcf recoverable.

Edina Deep

The relevant horizons defining identified closures at Edina Deep are:

- Nannygai Payzone Event
- Top Golden Beach Subgroup

A minor top Latrobe Group closure is also identified 1km east of Edina-1, but is considered insignificant with less than 1km^2 of areal and 10m of vertical closure, and so is not included in the reserves assessment.

The Edina-1 well was a test of the upper part of the Latrobe Group and only penetrated 316m into this unit (compared with over 1000m in Melville-1 on trend 13km to southeast). Edina-1 only reached the upper *L balmei* zone, and thus did not reach the deeper plays of the Grunter and Roundhead members or the Golden Beach Subgroup. The Edina Deep faulted anticline mapped at top Nannygai payzone level has an areal and vertical closure of 6.6km^2 and 70m. The fault block closure at top Golden Beach level has an areal and vertical closure of 6.9km^2 and 70m. Four potential reservoir seal pairs are modelled for the reserves determination, all identified from the Melville-1 well along trend. The first is the Grunter Member equivalent and the second the Roundhead Member. For the BRV determination these are both defined by the Nannygai Payzone Event. The third reservoir seal unit is a deep Volador Formation sandstone located overlying the Golden Beach Subgroup in Melville-1, thus this is defined (assuming phantoming) from the Golden Beach seismic event. The fourth reservoir unit modelled is the entire Golden Beach clastic sequence identified in Melville-1 and potentially sealed by volcanics at its top.

The likely gas columns entered for Edina Deep are varied from 0-70% for all levels, reflecting the likely access of the prospect to charge from the Central Deep, but in a more distal location on the Terrace. The charge / timing risk is 15% and reservoir risk 25%. The trap risk of 60% reflects the high depth conversion risk and the faulted structural nature of the trap. The seal risk is varied from a low of 20% (for the thick marine Kate Shale unit) to a high of 60% (for the Golden Beach, where possible absence of sealing volcanics may add to the existing fault seal risk).

Simulation results gave a POS of 24% of a MSV of 83MMb (STOIIP), with an MSV of 40MMb (recoverable) and low, middle and high recoverable oil reserves (P90, P50 & P10) of 15, 40 and 67MMb. Potential associated gas mean success volumes are 16Bcf (GIIP) with 7Bcf recoverable.

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