EAGLE BAY RESOURCES N.L.

VIC/P47

OFFSHORE GIPPSLAND BASIN

FARMOUT PROPOSAL

APRIL 2002

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EXECUTIVE SUMMARY

The offshore Gippsland Basin is one of Australia's premier petroleum provinces that has produced 3.6 billion barrels of crude oil and condensate and 5.2 TCF of natural gas. At its current production rate it still meets 25% of Australia's hydrocarbon liquid and gas requirements. Many commercial oil and gas fields have been discovered in both structural and stratigraphic traps. The primary reservoir is the sandstones at the top of the Latrobe Group but a number of other producing horizons occur at deeper stratigraphic levels. The basin has high exploration success rates and remains prospective at both the basin margins and in deeper water areas.

The farmout area, VIC/P47, is located on the northern margin of the Gippsland Basin (Figure 1). It covers an area of approximately 718 km^2 and has water depths increasing in a southerly direction from 20 metres to 78 metres. A closely spaced grid of 2D seismic and a reconnaissance 3D survey covers the southern portion of the permit. A new 3D survey will be acquired in this area in the first half of 2002. The northern portion of the permit has a sparse coverage of regional lines. Three wells have been drilled in the permit, two of which had good oil shows at top Latrobe level and the third had good gas shows at a deeper level.

The Patricia and Baleen gas fields are located immediately adjacent to VIC/P47. A production licence (VIC/L21) was granted over the fields in 2001. The Leatherjacket and Sperm Whale oil and gas discoveries lie to the east and west of the permit and the Tuna and Kipper oil and gas discoveries to the south.

The East Patricia prospect is located approximately 5 km to the east of the Patricia gasfield. The prospect has strong amplitude and AVO anomalies at the top Latrobe level similar to those over the Patricia and Baleen gasfields. In addition to the expected gas, East Patricia also has the potential for an oil leg. Good oil shows were present in both Flathead 1 and Whale 1 that lie immediately to the east of the prospect and oil legs are present in the gas fields to the south, east and west. Potential recoverable hydrocarbons at East Patricia are estimated to be 51 BCF and 19 MMSTB at P50 level. Immediately to the east of East Patricia is the smaller Whale Updip prospect that also has an amplitude anomaly.

In the southern portion of the permit deeper faulted plays in the Golden Beach and Emperor Subgroups are recognised. The Kipper oil and gas field is an example of the Golden Beach play and Judith 1, the only well in this area, had good gas shows at Emperor Subgroup level. To date the existing seismic coverage over these play types has not been adequate but the acquisition of a new 3D seismic survey in 2002 over this area will allow these plays to be properly evaluated.

1. Regional Geology

The offshore Gippsland Basin (Figure2) is a world class oil and gas province that has produced some 3.5 billion barrels of liquid hydrocarbons and 5.2 TCF of gas. Many commercial oil and gas fields have been discovered in both structural/stratigraphic traps. The prime reservoir unit lies at the top of the prospective Latrobe Group (Late Cretaceous to mid-Tertiary) and is represented by transgressive coarse-grained offshore barrier sandstones (Figure 3). A number of producing hydrocarbon accumulations occur at deeper stratigraphic levels and there is further potential at the basin margins as well as in deeper water areas.

The Gippsland Basin developed as a consequence of continental break-up between Australia and Antarctica during the Early Cretaceous and the separation of Australia from the Lord Howe Rise/Campbell Plateau during the Late Cretaceous. Early rifting produced the dominantly East-West trending Lake Wellington and Foster Fault Systems (Figure 2) which separate the Northern Terrace from the Northern Platform and the Southern Terrace from the Southern Platform respectively, but the entire rift system extended across Victoria into South and Western Australia. The opening of the Tasman Sea during Campanian time created extensional lineaments that follow a main Northwest-Southwest trend. The Rosedale and Darriman Fault Systems (Figure 2) are the most prominent features generated during that episode and they represent the northern and southern boundaries of the Central Deep, that hosts the giant oil and gas fields. Compressional tectonism during the Early Eocene and Early Miocene reactivated many of the older faults and established a series of Northeast-Southwest anticlinal axes as well as minor East-West folds. These inversion features represent the majority of the hydrocarbon traps within the basin.

The depositional history of the Gippsland Basin reflects the changing tectonic regimes. Early Cretaceous rifting was accompanied by the deposition of the Strzelecki Group (Figure 3), a thick fluvial succession that consists of basal conglomerates that uncomfortably overly Palaeozoic basement, lithic volcanoclastic sandstones, mudstones and some coals. The volcanoclastic material was derived from sources in the east (Lord Howe Rise). The total thickness of the Strzelecki Group is likely to exceed 3000m. Many fine grained organic-rich sediments in the group could represent potential source rocks. Maturity levels in the central part of the basin would be high enough to generate hydrocarbons.

The Late Cretaceous to mid-Tertiary Latrobe Group hosts all known hydrocarbon accumulations in the basin and remains the prime exploration target. The group is characterised by numerous stacked depositional cycles deposited in a progression from restricted rift basin to open marine shelf. Source rocks, reservoirs and seals are represented by a variety of lithologies and facies associations.

The Latrobe Group, including the Golden Beach and Emperor Subgroups, is dominated by coal-bearing fluvial and coastal plain siliciclastics. Sedimentation patterns were controlled by tectonism, and include synrift and drift phase facies associations. The division of the lower Latrobe Group into the Emperor and Golden Beach Subgroups (Figure 3) reflects a depositional hiatus prior to the opening of the Tasman Sea.

The sediments of the Emperor Subgroup represent the essentially two-fold facies association of the synrift period. Along the fault bounded basin margin, immature and mostly coarse-grained sandstones and minor mudstones were deposited in alluvial fan and braided stream environments. Much of the rift valley was characterised by an extensive system of deep lakes in which a sequence of up to 500m thick lacustrine mudstones accumulated. Occasional coarse-grained horizons indicated periodic influx of fluvial sediments. These lake deposits are widely known as the “Kipper Shale” which provides an excellent seal for the reservoirs in the deeper Latrobe Group and are particularly well developed in the Kipper oil and gas field.

Following a depositional break, the Golden Beach Subgroup developed above a subtle unconformity. This stratigraphic unit also consists of two distinct facies. Coarse-and fine-grained sandstones and minor mudstones were deposited within an extensive fluvial system near the basin margin. In the southeastern part of the basin, marine shales, identified in Angler-1, Anemone-1 and Archer-1 (often called the “Angler Shale”), represent the first basin-wide marine incursions. These shales have good sealing qualities and they may have source rock potential. A distinct intra-Campanian unconformity is recognised across the basin and marks the termination of Golden Beach sedimentation. The Golden Beach Subgroup is confined to the Central Deep and towards the north does not extend beyond the Rosedale Fault System. Well control in the southern part of the basin is limited, but it appears that Golden Beach sediments occur on the Southern Terrace although they were never deposited on the Southern Platform.

The development of the intra-Campanian unconformity coincided with a pronounced phase of extensional tectonism which produced the major throws now seen on intra-Golden Beach Subgroup faults and marked the onset of Latrobe Siliciclastics deposition in a well established drift phase setting. Tectonism was accompanied by widespread volcanism, the product of which are recognised as important seal rocks near the Rosedale Fault System where they reach thicknesses of up to 100m as drilled in the Kipper field. This volcanic activity has been linked to the shift of spreading centres from the Southern Ocean to the Tasman Sea during the Campanian. Active volcanism was not restricted to that time interval, but recurred episodically through to the early Oligocene.

The youngest sediments of the Latrobe Group are combined as the Latrobe Siliciclastics (Figure 3), representing the third subgroup of this stratigraphic unit. Overall excellent well control shows changing depositional patterns that are strongly influenced by marine transgressive and regressive cycles and pene-contemporaneous tectonism. In the Central Deep, the Latrobe Siliciclastics are up to 2500m thick and are represented by the *T.lilliei*. to *M. diversus* biozones (Late Campanian – Early Eocence). The succession thins out markedly towards the northern and southern margins, to commonly less than 100 metres and is for instance only 7 metres thick in Whale-1.

The basin’s most productive sedimentary unit is developed at the top of the Latrobe Siliciclastics, and is commonly referred to as the “coarse clastics”. The “coarse clastics” are a diachronous unit interpreted as a stacked and backstepping, transgressive series of extensive coastal to nearshore barriers associated with each of the depositional cycles. Above the “coarse clastics” is the Gurnard Formation, a condensed marine interval, represented by strongly glauconitic sandstones and mudstones. This unit is also diachronous and represents the reworked distal marine shelf units seaward of each of the progradational cycles. The Gurnard Formation varies in age, across the basin, encompassing *P.asperopolus* to Upper *N.asperus* biozones. It is oldest in the southeast and becomes progressively younger towards the north.

The carbonate-rich Seaspray Group is mid-Tertiary to Recent in age (Figure 3). It was deposited in a mature drift phase setting modified by episodic basin wide compressional events. By Early Oligocene time, marine conditions were fully established across the Gippsland Basin and carbonate-dominated sediments accumulated. The offshore Seaspray Group consists of two formations that show subtle lithological differences and are generally difficult to separate on wireline logs. The Lakes Entrance Formation is a clay-dominated calcareous unit that is occasionally strongly fossiliferous and forms a regional seal. The Gippsland Limestone is also clay-rich and comprises abundant marls. The unit has an overall higher carbonate content and contains many fossiliferous packstone horizons that developed during increased carbonate productivity in the Miocene under temperate climatic conditions.

VIC/P47 extends across parts of the Northern Terrace and Northern Platform (Figure 2). The Northern Terrace is bounded to the north by the Lake Wellington Fault System and to the south by the Rosedale Fault System. Over the platform, the Latrobe Group sediments overlie Palaeozoic basement and pinch out to the north (Figure 4). Across the Northern Terrace, the Latrobe Group gradually thickens and deepens to the south and is underlain firstly by the Strzelecki Group and then by the Golden Beach and Emperor Subgroups (Figure 2 and 4). The Golden Beach and Emperor Subgroups, however, are restricted to the southern part of the terrace and were only deposited south of a tectonic hinge-line along which the northern basin margin was uplifted during the Late Cretaceous. Coarse grained alluvial sediments, representing rapid uplift and erosion, were deposited along the basin margin and are well preserved in Hammerhead-1.

The Latrobe Group varies considerably in thickness across the Northern Terrace. It is 30m thick in Flathead-1 and Whale-1 (at a depth of 430 mss) and directly overlies the Strzelecki Group. In Judith-1, the Latrobe Group is 430m thick and uncomformably overlies the Golden Beach Subgroup at a depth of 1865 mss. In the Central Deep, to the south of the Rosedale Fault, the Latrobe Group commonly exceeds thicknesses of 1500 m.

VIC/P47 is located north of the Central Deep and lies on the main migration path of hydrocarbons generated to the south of the permit (Figure 5). Local gas generation has also occurred and is probably continuing as evidenced by the adjacent Patricia and Baleen dry gas fields. Good quality Latrobe Group reservoirs exist throughout most of the gazetted area. The Kipper and Tuna gas and oil fields are located immediately to the south and southwest of VIC/P47. The Lakes Entrance Formation and the Gippsland Limestone overlie the Gurnard Formation throughout the area and provide an effective regional seal.

It is believed that VIC/P47 was charged from source rocks of dominantly landplant origin (Type II/III). These are widely distributed throughout the Latrobe Group and generally exhibit high TOC values (greater than 2.0%), high Rock-Eval pyrolysis yields, and moderate to high hydrogen indices (mode 250) indicating a potential for oil generation. The richest Latrobe Group source rocks (of mainly humic to mixed type) occur within lower coastal plain and coal swamp facies. The source potential of the Golden Beach Subgroup is poorly documented due to minimal well control data. However, source rock facies similar to those of the Latrobe Group, are postulated to occur at deeper stratigraphic levels in the immediate vicinity of the Rosedale Fault System.

2. Seismic Data Base

The central and southern portions of the licence are covered by a closely spaced 2D seismic grid consisting primarily of surveys recorded in 1979, 1981 and 1988 (Figure 6). Well ties are provided by these surveys and regional surveys recorded in 1985, 1991 and 1992. Significant improvements in data quality have resulted from reprocessing of key lines from the 1978, 1981 and 1988 surveys. In addition, in 1988 a recognisance 3D survey was recorded in the southern area. This survey, covering an area of 48 km^2, has 150 metre dip line spacing and the data have been interpolated in the crossline direction from 150 to 50 metres. New 3D coverage in the southern area will be acquired as part of the Esso Northern Fields Survey in 2002. The northern part of the licence has a sparse coverage of regional lines.

3. Well Control and Adjacent Discoveries

3.1 Flathead 1

Flathead 1 was drilled in the VIC/P47 permit area in 1969 by ESSO. Good oil shows were present between 447 and 503 metres in the Gurnard Formation, Latrobe Siliciclastics and Strzelecki Group. Core data demonstrate reservoir quality in both the Latrobe Siliciclastics and the upper Strzelecki Group. Logs analysis indicates an average hydrocarbon saturation of 45% and 29% in the Gurnard Formation and Latrobe Siliciclastics respectively. Two production tests were run. Production Test 1 in the Strzelecki Group failed to recover any formation fluid. Production Test 2 in the Latrobe Siliciclastics recovered 16 barrels of fluid of an indeterminate origin. Both tests were conducted over intervals with fair to good core porosity and permeability. The tested intervals are considered likely to have been damaged by a combination of being drilled significantly overbalanced, acidized and swabbed. EBR has reviewed the show and test data and believes that the oil at Flathead 1 may be movable.

3.2 Whale 1

Whale 1 was drilled in the VIC/P47 permit area in 1989 by Hudbay (Australia) Ltd. The well had excellent oil shows between 439 and 473 metres in the Gurnard Formation and Latrobe Siliciclastics. Two drill stem tests were conducted within the interval. Neither recovered any hydrocarbons. Log analysis estimated hydrocarbon saturations of 40 to 50%. Hudbay concluded that the oil was residual and immovable although subsequent work has suggested that movable oil may be present.

3.3 Patricia/Baleen Gas Complex

Baleen 1 was drilled 7 km west of East Patricia by Hudbay in 1981. A 48 metre dry gas column was intersected in the Gurnard Formation and the Latrobe Siliciclastics. Two DST's over this interval flowed 1.8 and 6.3 MMCFD. Patricia 1 was drilled 2.5 km south of Baleen 1 in 1987. It also encountered a very dry gas column in the Gurnard Formation and the Latrobe Siliciclastics. The well was flowed at a maximum rate of 24.1MMCFD on production test.

3.4 Spermwhale Oil and Gas Field

The Sperm Whale gas and oil discovery was drilled on the Northern Terrace 12 km west of VIC/P47 by Hudbay in 1982. The field contains a dry gas column over a thin oil column in the top of the Latrobe Siliciclastics. The gas column was tested at 5.4 MMCFD and biodegraded oil was recovered by RFT.

3.5 Leatherjacket Oil and Gas Field

The Leatherjacket oil and gas discovery was drilled by Esso in 1986. The well is located 24 km southeast of East Patricia on the Northern Terrace. Leatherjacket 1 intersected a 25.5 metre gross oil column at the top of the Latrobe Siliciclastics at 724 metres subsea and a 7.7 metre gross oil column lower in the Latrobe Group. The Leatherjacket structure is a high side closure against a northeast/southwest trending reverse fault and is full to spill. The 23^o to 25^o API oil recovered from Leatherjacket is only moderately biodegraded, despite the shallow depth, low temperature and low water salinity in the Latrobe reservoir. The results of Leather Jacket are interpreted as encouraging analogue regarding the type of oil that may also be present in East Patricia where the principal target is approximately 500 metres subsea.

3.6 Kipper Oil and Wet Gas Field

The Kipper 1 discovery well was drilled by Esso in 1986 approximately 1.5 km from the southeastern corner of VIC/P47. Kipper 2 was drilled in 1987. The field has several oil bearing sandstones in the Latrobe Siliciclastics and a 328m gross gas column and 14 metre oil column in the sandstones of the underlying Golden Beach Subgroup. Kipper is estimated to have in place 750 BCF of wet gas and 30mmstb of 40-43°API oil.

3.7 Tuna Gas and Oil Field

The Tuna discovery was made in 1968 by Esso. The field has oil and gas columns in both top and intra Latrobe Siliciclastics. Cumulative oil production since 1979 has been in excess of 75 MMSTB.

3.8 Judith 1

Judith 1 was drilled in the southern portion of VIC/P47 by Shell in 1989. The primary objective of the well was the sandstones of the Emperor Subgroup in a rotated fault block. Strong gas shows were recorded in this section but reservoir quality was poor. Although the sandstones of the Golden Beach Subgroup had good porosity, no significant shows were recorded.

4. Patricia/Baleen Gas Development

The Patricia and Baleen gas fields are located approximately 7 km west of the East Patricia prospect. A production licence (VIC/L21) was granted over the fields in 2001.

Both the Patricia and Baleen gas accumulations are reservoired predominantly within the Gurnard Formation. The Gurnard Formation, which is approximately 40 metres thick, consists of micaceous, glauconitic, silty and bioturbated very fine to fine grained sandstones with interbedded sideritic layers. It is overlain by calcareous claystones of the Lakes Entrance Formation.. The reservoir has good reservoir characteristics with porosities above 30% and permeabilities in the 50 to 300 md range. The reservoir has flowed on DST 6.3 MMCFD in Baleen 1 and 24.5 MMCFD in Patricia 1.

Prominent amplitude anomalies and flat spots are present over both fields. These DHI's are in good general agreement with the field areas. The gas is dry, consisting of 98% C1 and insignificant levels of NGL, condensate or inerts.

5. Review of Farmin Opportunities

5.1 East Patricia

The East Patricia prospect is located on the flank of a large anticline (the Flathead High) on the Northern Terrace that is bounded to the north by the Lake Wellington Fault (Figure 7). The Patricia Baleen development is located approximately 7 km to the west.

The Flathead High is a large feature formed by compression and reversal of the Lake Wellington Fault (Figures 8 and 9). Two wells, Flathead 1 and Whale 1, have been drilled on the high. Both encountered at the primary target level of approximately 440 metres the Gurnard Formation, and a very thin Latrobe Siliciclastic section that unconformably overlies the Strzelecki Group. The Gurnard Formation reservoirs the majority of reserves at Patricia and Baleen.

Seismic coverage over the prospect is good, consisting of a grid of 2D lines of predominantly 1979, 1981 and 1988 vintages.

The East Patricia prospect has strong amplitude anomalies at the top Gurnard level that have been mapped by all previous Operators (Figure 10). Similar anomalies are present at Patricia and Baleen where they closely coincide with the gas accumulations. Seismic line GL88A-54 illustrates the distribution of the anomalies (Figure 9). AVO anomalies are also present and previous operators have observed that they are present in areas that do not exhibit amplitude anomalies. The amplitude anomalies and the AVO's provide compelling evidence for gas charge for the prospect. However, unlike the anomalies at Patricia and Baleen, the East Patricia anomalies are not coincident with structure and a more complex stratigraphic and /or structural trap is implied.

The reservoir at East Patricia is expected to be a combination of the Gurnard Formation, the Latrobe Siliciclastics and the Strzelecki Group. The Gurnard Formation at Patricia and Baleen is an excellent reservoir (see section 4 above). East Patricia's proximity and the presence of similar DHI's suggests that the Gurnard Formation will be of similar reservoir quality on the flanks of the Flathead High.

The top of the Latrobe Siliciclastics is the principal reservoir in the Gippsland Basin. This sequence is only 7 metres thick at both Flathead 1 and Whale 1, but thickens off the crest of the Flathead High. Core data for the coarse clastics in Flathead 1 give an average porosity of 37.5% and an average permeability of 506md. In Whale 1 the reservoir consists of coarse sandstones with varying porosities of up to 23%. At Patricia 1 the reservoir is described as a fine to very coarse sandstone with very good to excellent visual porosity and at Baleen 1 a DST indicated the interval had an average permeability of 747 md.

At Flathead 1 the Strzelecki Group has good reservoir characteristics in the deeply weathered upper section. Esso report that the top 60 metres has fair to good reservoir characteristics and core over the upper 46 m has a good net to gross ratio, an average porosity of 32.5% and an average permeability of 115 md. At Whale 1 the Strzelecki Formation consists of sandstones and siltstones with generally low porosities and at Baleen and Patricia it consists of claystones, siltstones and very fine to fine sandstones with siliceous and argillaceous matrices. Baleen 1 log derived porosities average 20% although RFT's indicate the formation is tight. Logs also suggest the presence of a 150 metre weathered zone at Baleen 1. In areas of better permeability the Strzelecki Group is a secondary exploration target.

Dry gas is present in other fields reservoired in the top Latrobe on the Northern Terrace eg Sole and Sperm Whale, but fields at the Golden Beach Subgroup level deeper in the basin tend to have wetter gasses with higher CO_2 contents. The composition of the fill in East Patricia is therefore uncertain although a dry gas is considered more likely.

Most of these fields also have oil columns or residual oil columns and excellent oil shows have been recorded in Flathead 1 (Figure 11) and Whale 1. Oil has been recovered from Kipper, Leatherjacket and Sperm Whale, which have oil columns of 14, 33 and 2 metres respectively. The Tuna platform has been producing oil since 1979. The thick interval of shows at Flathead 1 and Whale 1 indicates that the Flathead High has been on a migration path and migration path analysis at top Latrobe Group level indicates that it still is (Figure 5). The East Patricia prospect is therefore considered likely to have an oil leg although its thickness is difficult to forecast.

East Patricia reserves have been estimated assuming gas fill to the lowest level indicated by the DHI's on the western extremity of the prospect. The minimum field area has been determined assuming the field is limited to the largest single area of DHI's mapped by Lasmo. The maximum area includes all DHI's mapped by Lasmo.

The minimum bulk rock volume has been determined assuming a constant combined thickness of 30 metres of Gurnard Formation and Latrobe Siliciclastics reservoirs. The maximum BRV assumes a reservoir system comprising the Gurnard Formation, Latrobe Siliciclastics and weathered Strzelecki Group with an average gross pay thickness over the field of 50 metres. The most likely BRV was determined using the maximum and minimum BRV's and assuming a log normal distribution. Oil reserves have been estimated assuming a 5, 10 and 15 metre oil column beneath the gas cap. Hydrocarbon in place and reserves estimates are summarised below.

GAS CASE	Minimum	Most Likely	Maximum
Gas in Place (BCF)	29	69	163
Recoverable Gas (BCF)	18	51	131
OIL CASE			
Oil in Place (MMSTB)	15	53	147
Recoverable Oil (MMSTB)	5	19	51

5.2 Whale Updip

Whale 1 was drilled 2.2 km east of Flathead 1 by Hudbay Oil in 1981. Excellent cuttings and sidewall oil shows were present throughout the Gurnard Formation and the Latrobe Siliciclastics over the interval 439 to 473 metres. The best shows were at 472 metres at the base of the Latrobe Siliciclastics. Logs indicate hydrocarbon saturations of 45 to 55% in the base of the Gurnard Formation although wireline testing did not recover any hydrocarbons. RFT pressure data are not conclusive with respect to a water or oil gradient. Log porosities of up to 20% and 23% are present in the base of the Gurnard Formation and Latrobe Siliciclastics respectively. Two cased hole DST's were conducted in the Gurnard Formation. The first recovered 8.4 barrels of what 'appears to be formation water' from a zone with greater than 1000 md. The second recovered less than a third of a barrel of mud from a tight zone.

The presence of a strong amplitude anomaly on the Whale structure above the well implies the presence of gas and therefore a valid trap. The ambiguous results at Whale 1 do not rule out the possibility of the Gurnard Formation having a movable oil column which in an updip location would also be reservoired in the Latrobe Siliciclastics.

5.3 Golden Beach and Emperor Subgroup Plays

The Golden Beach and Emperor Subgroup plays are located in the Rosedale Fault System in the southern portion of the permit (Figure 1). No top Latrobe closures are expected to be present in the area. A reconnaissance 3D seismic survey with 150 metre dip line spacing covers these plays (Figure 6). The data were interpolated to 50 metres in the cross line direction but the interpolation has resulted in a very smeared appearance and very poor fault definition., In addition the area has a sparse coverage sparse of 2D lines. Eagle Bay will also have access to the portion of Esso's Northern Fields 3D survey that will be acquired within this part of VIC/P47 in 2002. Well control is provided by Judith 1, Admiral 1 to the east, Kipper 1 and 2 to the southeast and the Tuna wells to the southeast.

The Golden Beach Subgroup play consists of lowside fault closures similar to the Kipper closure (Figure 12). The reservoir is Golden Beach Subgroup non-marine sandstones that have been intersected in Kipper 1 and 2, Judith 1 and Admiral 1. At Kipper porosity ranges from 16 to 20%, permeability from 20 to greater than 1000 md and net to gross from 34 to 66%. At Admiral 1 they are well developed and up to 10 metres thick with porosities up to 24% and a net to gross of 85%, and at Judith 1 the reservoir has fair to good visual porosity and log porosities of 17 to 24% with an average of approximately 20%. The vertical seal consists of weathered Campanian volcanics. Weathered volcanics are the seal for the Kipper accumulation, and shows and hydrocarbon accumulations have also been found beneath volcanics on the down thrown side of faults at Tuna, Manta and Sunfish. Lateral seal is provided across the controlling fault by juxtaposition against the Kipper Shale in the Emperor Subgroup or the Strzelecki Group.

Previous Operators have recognised the potential for the Golden Beach Subgroup play. The play was a secondary objective in Judith 1, but probably failed due to the presence of reservoir sands in the upthrown fault block (Figures 12 and 13). The play was the primary objective in Admiral 1 which had gas shows at that level. However, the volcanics were only 11 metres thick and may not have extended north to the fault to provide top seal. Previous Operators have identified one lead of this type (North Kipper) within VIC/P47 (Figure 14). The Northern Fields 3D seismic survey is expected to upgrade the play by providing improved fault definition and greater confidence to predict reservoir and seal distribution in the fault blocks.

The Emperor Subgroup play consists of an Emperor Subgroup reservoir with a Kipper Shale vertical seal. This play was the primary target in Judith 1 which had excellent shows at the objective level but poor reservoir quality (Figures 12 and 13). Reservoir quality is also poor in both Kipper 1 and Admiral 1. The development of the play will be dependent on the identification of better quality reservoir facies. Gas and oil were recovered on RFT from this interval in Kipper 1. The Kipper Shale is the vertical seal for the play. It is present in Kipper 1, Judith 1 and Admiral 1 where it is a thick and effective seal. The Kipper Shale also forms the lateral seal either by facies change or by fault juxtaposition. The Northern Fields 3D seismic survey is expected upgrade the play by providing improved fault definition and greater confidence to predict reservoir and seal distribution in the fault blocks.

One strong lead has been identified in the North Kipper area. It is estimated to have an area of 9 km^2 and 100 metres of vertical relief. Recoverable hydrocarbons are estimated to be 167 BCF of gas or 100 MMSTB of oil.

6. Permit Commitments

YEAR	DATES	WORK COMMITMENT	EXPENDITURE COMMITMENT
1	28/5/01 to 27/5/02	Data review, seismic studies (PSDM, AVO), 500 km 2D seismic survey.	$700,000
2	28/5/02 to27/5/03	1 well	$5,000,000
3	28/5/03 to27/5/04	1 Well	$5,000,000
4	28/5/04 to 27/5/05	200 km 2D seismic survey	$300,000
5	28/5/05 to27/5/06	1 Well, geological and geophysical review.	$5,000,000
6	28/5/06 to 27/5/07	Geological and geophysical review.	$200,000

For further information regarding these opportunities please contact:

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