Exploration Permit

VIC/P42

Quarterly Report (adjusted period)

14 December 2000 – 13 May 2001

Bass Strait Oil Company Ltd

CONFIDENTIAL

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VIC/P42

QUARTERLY (AS ADJUSTED) REPORT FOR THE PERIOD

14 DECEMBER 2000 to 13 MAY 2001

1. PARTICIPATING INTERESTS

Bass Strait Oil Company Ltd	100% (Operator)

2. GOVERNMENT RELATED MATTERS

Representatives of the Board of BSOC met with the DNRE on 7th February and discussed their activities.

In March 2001 a prospectivity report was delivered to DNRE describing Vic/P42 prospects and leads.

A referral was submitted on 14th March under the EPBC Act for the acquisition of a 3D seismic survey in Vic/P42 to cover the northeast area of the permit.

3. EXPLORATION ACTIVITIES

3.1 Vic/P42 Evaluation

In January 2001 a study on economics of production of notional field developments in Vic/P42 was initiated from the IHS Energy Group.
Project is to consist of:

a. Project Development Scenario, 2 cases, and
b. Economic Analyses of these 2 cases to generate NPV's.

a. Development

Case 1:	Reserves:	47 mmbbls.
	Reservoirs:	stacked reservoirs, 3.
	Reservoir Depth:	ca 3200m (target range 2700 – 3500m).
	Well Initials:	4500 bopd.
	Export:	assumed via Kingfish facilities as before.
Case 2:	Reserves:	257 mmbbls.
	Reservoirs:	as for case 1 above.
	Reservoir Depth:	as for case 1 above.
	Well Initials:	9000 bopd.
	Export:	either via a 50 km pipeline to nearest landfall (ca AUD 50 million Capex), or via FPSO.

These development scenarios and their corresponding NPV's are to be provided, including illustrative material. Economic analyses are to include a plot showing, but not necessarily limited to, net cash flow and PV on a year by year basis

The object of the exercise is to demonstrate a practical development scenario and the corresponding NPV's for the case 1 and case 2 reserves, thus giving an indication of the reward which would accompany success both at the 'most likely' and 'upside' levels.

A prospectivity report was produced in February 2001 and was submitted to the DNRE in March 2001. The report highlights the prospectivity of Vic/P42 and identified prospects and leads.

Ten exploration wells have been drilled in the area, one of which (Omeo-1, 1983), discovered a 38m to 42m net hydrocarbon pay, equivocally believed to be gas although possibly with light oil. The remaining wells failed to encounter significant hydrocarbons, but have subsequently been shown to be invalid tests. The Omeo accumulation was downgraded after a downdip follow-up well, Omeo-2A, failed to encounter moveable hydrocarbons. A preliminary reserves assessment suggests approximately 50bcf may exist at Omeo-1 (GIIP), although poor seismic data precludes definition of the extent of the field. An updip faulted anticline (Omeo Updip) has been identified, together with downthrown closures (West Omeo and East Omeo). Significant gas potential exists in these extensions of the Omeo-1 pay with, for example, East Omeo having potential for 450bcf (GIIP).

The Melville Prospect in the central east of Vic/P42 shows many similarities with the Archer and Anemone areas of Vic/P45. The structure is a downthrown rollover with fault independent four way dip closure within the Golden Beach Sub-group. Reserve estimates give P90, P50 and P10 of 72, 140 and 251MMb respectively.

A structural / pinch-out prospect, Hemingway, is interpreted within the Latrobe Siliciclastics "Coarse Clastics" barrier sands. A seismic event, interpreted to be related to the base of a barrier sand sequence, is interpreted to sub-crop at Top Latrobe Group level on a plunging structural nose. The interpretation of a structural closure (77 km^2) over Hemingway is supported by the existence of an amplitude dimming at the Top Latrobe, structurally concordant at the culmination of the prospect. This dimming may represent a gas filled sand body. A substantial closure remains downdip of this interpreted DHI, which may be oil bearing. In the scenario that the DHI is valid, reserves estimates for oil give a 43% probability of mean success volumes of 148MMb and gas reserves estimates give 80% probability of a mean success volume of 0.12Tcf. Unrisked oil reserves have P90, P50 and P10 estimates of 50, 260 and 648MMb respectively. Unrisked gas reserves have P90, P50 and P10 estimates of 0.05, 0.15 and 0.36Tcf respectively.

Additional leads in Vic/P42 have been identified with areal closures up to 17 km^2 offering follow-up potential in the block. Melville and Hemingway are considered mature for drilling whilst the Omeo leads require further seismic definition.

In May 2001 reserves estimates were produced for Hemingway prospects.

Hemingway

Hemingway Reserves Appraisal

A stratigraphic play, which is as yet untested, exists where coastal barrier sands have migrated landward over back barrier / lagoonal and lower coastal plain deposits which provide seat seal. Occasionally these coastal barrier deposits are overlain directly by Lakes Entrance Formation marine shales and marls, deposited as a result of rapid marine transgression, thus providing a good top seal as is the case in the interpreted Hemingway Prospect.

Hemingway is a combined dip and stratigraphic trap at the top "Coarse Clastics". The schematic cross section along plunge from Pike-1 in the southeast through Hemingway to Edina-1 in the northwest demonstrates the nature of this interpreted closure. Two seismic events within the upper Latrobe Siliciclastics are observed to truncate at the top of the Latrobe Group. The lower event is seen to be present in the Pike-1 and Devilfish-1 locations. The upper event is restricted to an area between the Edina-1 and Pike-1 locations. This is interpreted to represent a barrier sand, younger than that encountered in Pike-1, which is truncated by erosion or restricted by deposition. On the top 'Coarse Clastics' depth map the Hemingway Prospect can be seen to be restricted to the plunging nose downdip of Pike-1 and updip of the Edina-1 location. As such, it is interpreted to be closed. Individual barriers are believed separated by shale seat seals deposited in lagoonal / back barrier settings.

The interpretation of a structural closure over Hemingway is supported by the existence of an amplitude dimming at the Top "G" Event (Top Latrobe), interpreted to represent a direct hydrocarbon indicator, present at the crest of the prospect. This dimming may represent a gas filled sand body.

Further evidence for the occurrence of a barrier sand, thickest around Hemingway, is seen on the isopach map of the interval from Top "Coarse Clastics" to Top *M. Diversus* event. The thickening of the sequence over Hemingway is attributed to erosion and depositional thickness variations. These thickness variations to a certain extent explain the prominence of the "Hemingway" and Edina Structure. The isopach map over this upper Latrobe Siliciclastics interval shows a concordance with the limit of the Hemingway Barrier from the subcropping seismic event, with the 150 to 160 m thickness contour from the isopach. This allows an estimate of the thickness of the "Hemingway Barrier" sandstones to be made, it being that area on the isopach map thicker than 150-160m.

The eastern margin of the barrier complex is possibly fault controlled. Such faulting may be a result of differential compaction over the barrier complex. Whilst relatively unfaulted at the top "Coarse Clastics" level over Hemingway, minor faults are evident with throws of less than 10msec. Such faults occasionally appear to control the westerly extent of the amplitude dimming and may explain its occurrence being not perfectly concordant with structure, but with some fault dependence. Faulting may therefore also control pay distribution.

The Gurnard Formation, which is a potential thief zone to top Latrobe hydrocarbon pay, is interpreted to have a limited depositional extent through Edina-1 and ending northeast of the Hemingway Prospect. As such, risk of the Gurnard Formation thief zone destroying top seal is considered low for the prospect. The pinch-out of the Gurnard Formation is observed on seismic some 4 km south of Edina-1. Some Gurnard Formation equivalent sequence is interpreted to exist west of the Hemingway barrier and abutting the barrier sands. This poses a trap risk if this equivalent sequence is permeable. However, its "back barrier" depositional environment suggests this equivalent sequence will be low energy and sand poor and represent a lateral seal.

An alternative interpretation of the amplitude dimming on the Top "G" Event seismic reflection (top Latrobe) is that it may represent thinning of acoustically hard carbonate streaks within the base of the Lakes Entrance Formation (Shell, 1989). Such an interpretation is feasible, although could be pessimistic given the structural concordance of the feature. Shell had only limited seismic coverage and did not have the benefit of the extensive 1992 surveys at the

time of their interpretation. If the amplitude anomaly does not represent a gas cap, a significant risk exists for the occurrence of closure at Hemingway, specifically seat seal and top seal.

The crest of Hemingway is interpreted at 1870 m bmsl, and the lowest closing contour (LCC) at 2240 m bmsl, giving a vertical closure of 370 m. The areal closure, equal to the interpreted subcrop of the Hemingway Barrier, is 77.2 km^2.

Hemingway Prospect appraisal

The appraisal of the Hemingway Prospect, given the occurrence of an amplitude anomaly, is made assuming two potential scenarios. The first scenario assumes that the amplitude anomaly represents gas pay within the 'Coarse Clastics' or possibly within a waste zone of the Gurnard Formation. In this scenario, trap and seal risk for gas is zero and low for oil. A reservoir risk exists in the occurrence of the DHI within a waste zone, but source, maturation, timing and migration risks are zero for gas and low for oil. The risks applied for this scenario are shown in table 5. The gas-oil contact is estimated within the range of interpreted limits of the amplitude anomaly and the oil-water contact is estimated between the GOC and the lowest closing contour with equal likelihood.

In the second scenario it is assumed that the amplitude anomaly is not related to hydrocarbon fill, but a purely lithological effect. In this scenario, a far greater trap and seal risk exists, together with source, maturation, timing and migration risks (see table 6). The estimates of gas versus oil proportions are made assuming the gas column varies between 20 to 50% of the total hydrocarbon column height. This assumption is made based on the arguments that the catchment is predominantly oil prone. The spill point for the Hemingway Prospect is problematic to determine, given its lack of structural control. Therefore, spill point is entered with equal likelihood between the crest of the structure and the lowest closing contour mapped. Clearly a simplistic assumption, but the only one viable.

The gross reservoir thickness has been determined for the two scenarios using the isopach map from Top Coarse Clastics to *M. Diversus* interval. Assuming the 150 - 160 m contour represents the sub-crop limit, a weighted average (based on area) for the Hemingway Barrier thickness was estimated to be 25 m. A more accurate approach would have been to integrate the reservoir thickness across the structural closure, but the technology to achieve this was not currently available. The thickness of the barrier sand in Edina-1, by comparison, is 38 m.

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 7 demonstrate these high recovery factors (Rahmanian *et al.*, 1990).

Table 7 - recovery factors

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

The results for scenario 1, assuming the occurrence of a gas cap manifested through the amplitude anomaly, are positive and encouraging. Risked reserves estimates for oil give a 43% probability of mean success volumes of 148MMb (see table 5). Likewise, gas reserves estimates give 80% probability of a mean success volume of 0.12Tcf. Unrisked oil reserves have P90, P50 and P10 estimates of 50, 260 and 648MMb respectively. Unrisked gas reserves have P90, P50 and P10 estimates of 0.05, 0.15 and 0.36Tcf respectively.

The results for scenario 2, assuming that the amplitude anomaly is a lithological effect and thus not in itself supportive of the occurrence of hydrocarbons, are less encouraging but still suggesting potential. In addition, a major uncertainty is identified in the nature of the hydrocarbon fill i.e. oil versus gas. Risked reserves estimates for oil give an 18% probability of mean success volumes of 38MMb (see table 6). Likewise, gas reserves estimates give 18%

probability of a mean success volume of 0.01Tcf. Unrisked oil reserves have P90, P50 and P10 estimates of 4, 175 and 554MMb respectively. Unrisked gas reserves have P90, P50 and P10 estimates of 0.00, 0.03 and 0.16Tcf respectively. It is notable that there is a 14% probability of oil reserves being in excess of 30MMb for scenario 2. Unrisked reserves assuming that the fill is 'oil only' give P90, P50 and P10 estimates of 5, 194 and 714MMb respectively. Likewise, in a 'gas only' case, P90, P50 and P10 estimates of 0.01, 0.40 and 1.44Tcf are estimated.

By comparison, the independent geologists report (unpublished) indicated that in the 'most likely' case Hemingway reserves are 324MMb and in the 'high case' 1012MMb.

At this stage there are no stronger arguments for or against the two scenarios, although the structural concordance of the amplitude anomaly adds confidence to its interpretation as a DHI and adds weight to scenario 1 being the more likely.

Table 5 - Risks, input parameters and reserves for Hemingway Prospect Scenario 1

Scenario 1- Hemingway prospect appraisal - amplitude anomaly is gas cap			
Risk Assessment	Reservoir		80%
	Source and maturation		100% for gas, 80% for oil
	Trap and seal		100% for gas, 70% for oil
	Timing and migration		100% for gas, 95% for oil
	Probability of success (assuming scenario 1)		80% for gas, 43% for oil
Geological variable	Distribution	Description	
Gross reservoir thickness (m)	normal	25 m ± SD 10m, based on weighted average from isopach map	
Net to gross	histogram	Taken from Shell (1989) plots for Gippsland Basin Barrier facies, average of 80% with minimum of 30-40%.	
Porosity	normal	Taken from Shell (1989) plots for Gippsland Basin barrier facies, average 25% +_ SD 2%	
Saturation (Sh)	normal	So aver. 60%, Sg aver. 65%	
Form. Vol. Fact.	normal	1.4 ± SD 0.1	
Gas expansion fact.	normal	200 ± SD 10	
GOC	normal	1980 m ± SD 20 m	
OWC	rectangular	Between GOC and LCC (2240 m)	
Rec. fact. oil	normal	Mean 60%, ± SD 8% cut-offs 40-75%	
Rec. fact gas	normal	Mean 70%, ± SD 8% cut-offs 60-80%	
Risked oil results	43% probability of success of mean reserves of 148MMb		
Risked gas results	80% probability of success of mean reserves of 0.12Tcf		
Unrisked reserves estimates	Oil (MMb)		
	P90	P50	P10
	50	260	648
	Gas (Tcf)		
	P90	P50	P10
	0.05	0.15	0.36

Table 6 - Risks, input parameters and reserves for Hemingway Prospect scenario 2

Scenario 2- Hemingway prospect appraisal - amplitude anomaly is lithological effect			
Risk Assessment	Reservoir		80%
	Source and maturation		80%
	Trap and seal		30%
	Timing and migration		95%
	Probability of success (assuming scenario 2)		18%
Geological variable	Distribution	Description	
Gross reservoir thickness (m)	normal	25 m ± SD 10m, based on weighted average from isopach map	
Net to gross	histogram	Taken from Shell (1989) plots for Gippsland Basin Barrier facies, average of 80% with minimum of 30-40%.	
Porosity	normal	Taken from Shell (1989) plots for Gippsland Basin barrier facies, average 25% ± SD 2%	
Saturation (Sh)	normal	So aver. 60%, Sg aver. 65%	
Form. Vol. Fact.	normal	1.4 ± SD 0.1	
Gas expansion fact.	normal	200 ± SD 10	
GOC	rectangular	Between 20% to 50% of hydrocarbon column gas, remainder oil.	
Spill / OWC	rectangular	Between crest (1870 m) and LCC (2240 m)	
Rec. fact. oil	normal	Mean 60%, ± SD 8% cut-offs 40-75%	
Rec. fact gas	normal	Mean 70%, ± SD 8% cut-offs 60-80%	
Risked oil results	18% probability of success of mean reserves of 38MMb		
Risked gas results	18% probability of success of mean reserves of 0.01Tcf		
Unrisked reserves estimates	Oil (MMb)		
	P90	P50	P10
	4	175	554
	Gas (Tcf)		
	P90	P50	P10
	0.00	0.03	0.16

3.2 Exploration well Melville-1

Plans for the drilling of Melville-1 continued with RBT in Perth representing BSOC in a meeting with potential oil companies for mobilising a drilling rig.

Present at the meeting were representatives from Woodside / Shell, OMV, Eagle Bay and RBT representing BSOC. A representative from Esso was also present via a telephone link.

Agenda and Minutes for the meeting were as follows:
Schedule

Woodside plan to take the Ocean Bounty to the Bass Strait region around early May 2001, the sequence of wells to be drilled was proposed as follows;

BSOC	*Gippsland Basin*
Woodside	*Otway Basin (two wells)*
Eagle Bay	*Gippsland Basin*
Esso	*Gippsland Basin*
OMV	*Gippsland Basin*

Move to Shell Todd in New Zealand.

Comments on the sequence;

Woodside are meeting difficulties obtaining environmental approval for their wells, hence the delayed commencement.

Esso are awaiting joint venture (BHP) approval for their well, approval is expected in the next few weeks.

OMV do not expect approval for any wells until January 2002, therefore they effectively fall out of this programme.

Eagle Bay have the money and are keen to drill 3Q2001.

BSOC, May commencement of drilling may be too early?

Co-operation Agreement

Woodside have a draft agreement with their lawyers, a copy should be issued to consortium members soon. The key aspect of the agreement is to share the mobilisation cost of the rig and associated services between the members on a per well basis. The mobilisation cost is estimated to be in the region of US$ 3,000,000. (The rig rate is US$ 80,000 per day)

Shell Todd intend to pick up the rig from the last operator and assume responsibility for demobilisation costs.

The issue of Helicopter services and shore base facilities raised some comments. Woodside only wish to provide a helicopter for their own wells, Esso do not intend to allow anyone else to share their Sale shore base facility. Neither of these two issues are insurmountable problems but rather a reflection of the self centred nature of these two large companies.

Material

It was felt to be beneficial if primary and back up material could be standardised wherever possible to minimise cost. Again Woodside and Esso were reluctant to offer any casing or wellhead equipment they currently hold for this purpose.

Site Survey

It was proposed that Woodside look at arranging a consortium site survey too in the region, they agreed to do this and revert at the next meeting.

Next Meeting

A follow up meeting is scheduled for 16th February 2001.

In May 2001 preparations for the drilling of Melville-1 continued with an AFE for Melville-1

AUTHORITY FOR EXPENDITURE (Final Estimate)			
PERMIT/LEASE:	VIC / P42	AFE NO:	tba
BUDGET CATEGORY:	Exploration Drilling	GROSS AMOUNT(US$):	7,072,110
PROJECT NAME:	Melville 1	(for Bare Dry Hole)	
STARTING DATE:	September, 2001		
RIG	Ocean Bounty		

WELL DESCRIPTION

Vertical exploration well drilled in permit VIC / P42 using a semi submersible rig.

Water Depth:	70 m (+/- 5m)
Well Program:	36" hole to set 30" conductor @ ~120 mSS 17.5" hole to set 13 3/8" casing @ ~2400mSS 12 1/4" hole to set 9 5/8" casing @ ~3300mSS 8 1/2" hole to TD of 3800mSS Log and abandon well.
Assumptions:	No mob. / demob.included Dry hole basis No operator overheads have been included.

Melville 1 Well	ESTIMATED TIMING
OPERATION	BARE DRY HOLE (DAYS)
Rig Mobilisation	
Rig Demobilisation	
Run anchors and rig up	2.00
Run TGB & drill 36" hole to approximately 120 m	1.00
Run and cement 30" conductor w/20" shoe joint	1.00
Drill 17.5" hole with LWD to ~2100 mSS	6.00
Run and cement 13 3/8" casing swedged back to 18 3/4" wellhead	2.00
Install BOP and pressure test	1.50
Drill out shoe, conduct LOT	1.00
Drill 12 1/4" hole with LWD to ~3000 mSS	4.00
Log, run and cement 9 5/8" casing	3.00
Drill out shoe, conduct LOT	1.00
Drill 8 1/2" hole to TD of 3500mSS	2.00
Log	1.50
Abandon well.	2.50
Rig down and pull anchors	1.00

3.3 Seismic Acquisition & Processing

In Jan 2001 it was learnt that that Exxon Mobil will be shooting a 3000km^2 3D over the entire northern margin of the Gippsland Basin where they have most of the licences. It was believed that this will be acquired in Q3 2001. Their objective is in targeting intra-Latrobe and Golden Beach closures, which require a better quality of seismic to identify. This survey would form the basis of mobilisation of a seismic vessel to the Bass Strait, critical for the acquisition of 3D in Vic/P42.

4. REPORTS SUBMITTED

Other than the previous Quarterly Report, no reports were submitted during this report period.

5. HEALTH, SAFETY AND ENVIRONMENT

5.1 Incidents

There were no health, safety or environmental incidents recorded during the report period.

5.2 Environmental Approvals

There were no environmental issues submitted for approval this quarter.

6. ESTIMATED EXPENDITURE FOR THE QUARTER

Estimated expenditure for the reporting period is detailed below:

Activity	Estimated Expenditure ($000's)
Drilling Preparations	25
Permit Administration	30
Seismic (Reprocessing)	NIL
Geological & Geophysical	25
Seismic (Acquisition)	NIL
Total	80