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License T/14P, Bass Basin
Yolla Discovery
Retention Lease

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EXECUTIVE SUMMARY

The Yolla Gas Field was discovered by Amoco and partners in the T/14P License in the Bass Strait in the third quarter of 1985. After testing at rates of up to 15 million cubic feet per day (MMCFD), the Yolla-1 well was suspended while participants evaluated potential development opportunities.

The field is estimated to contain 413 billion cubic feet (BCF) and 22.5 million barrels (MMBL) from two separate intervals in the Eastern View Coal Measures Group. Reserves are divided into the proved and probable categories since the fault block to the north is downthrown with respect to the block containing the Yolla-1 well. Strong evidence exists, however, that communication across the fault through juxtaposition is likely to have occurred, giving confidence that hydrocarbons will be present on both sides of the fault. Since no oil-water contact was observed in the lower zone, the structure could potentially be much larger.

Although the field has been determined to be commercial at the estimated reserve level and competitive pricing, the current lack of market opportunities precludes development at this time. A detailed gas market study has identified the need for additional energy supplies in the Tasmanian system by 1997 assuming a forecast based on historical growth patterns only. For this study, a conservative demand profile was generated assuming that only a portion of these incremental energy requirements would be supplied by Yolla gas. Yolla is well suited to meet this need and would be able to meet the demand for 21 years. Once productivity declines, the location of Yolla is ideal for connection across the remainder of the Bass Strait to the mainland for future gas supply.

The development plan envisioned includes supplying gas to the Tasmanian market through 12 producing wells to be staged in as deliverability is required. Production will be accomplished with a manned, fixed steel platform with offshore compression. Transportation to shore will be through a single two phase pipeline. Onshore facilities will dry and sweeten the gas as well as provide storage for liquids before sale.

Results of the economic analysis show that the project is profitable assuming an average gas price of $5.00/GJ for HECT and industrial/commercial users and subject to obtaining the contractual commitments to support the sales volumes shown in Attachment No. 27. Using these assumptions, the project generates an internal rate of return of 20% with a cumulative undiscounted cash flow of A$4977 million. The gas price and sales volume used in the economic analysis are derived from the gas market analysis which indicate the price to be attractive as a replacement fuel at feasible sales volumes.

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INTRODUCTION

General:

The Yolla gas discovery is located approximately 135 kilometers offshore due north of Burnie, Tasmania in the Tasmanian waters of the Bass Strait (see Attachment No. 1a). The structure was discovered by Amoco and partners with the drilling of the Yolla Well No. 1 in July, 1985. Test rates of two hydrocarbon bearing zones of up to 15 MMCFD proved the existence of the first significant gas reserves discovered in the Bass Straits. The well was subsequently suspended and a review of the commerciality of the field undertaken.

Although the Yolla field is determined to hold sufficient reserves to support development, the present lack of a gas market in either Tasmania or Victoria prevents implementation of the project at this time. A thorough review of projected market conditions strongly suggests that this situation will change and development will become viable in the future. For this reason, the participants in License T/14P have elected to apply for a Retention Lease.

Background:

Amoco and South Australia Oil and Gas (SAGASCO) farmed into T/14P in April 1984 from the Bass Cue Group. Amoco and SAGASCO assumed a farm-in obligation in the license of $7 Million Australian gross expenditure commitment which covered a $4.5 Million Australian expenditure commitment to the government.

In 1984 and 1985, Amoco and partners acquired over 4,000 kilometers of seismic data and reprocessed 3,000 kilometers of seismic data in T/14P prior to drilling two wells in the license.

The Amoco Yolla-1 was spud in June 1985 and drilled to a total depth of 3,345 meters. Designed to test closure through the Eastern View section, the well discovered hydrocarbons at the top of the Eastern View, testing at rates as high as 11.8 million cubic feet of gas per day (MMCFD) and 892 barrels of condensate per day (BCPD) on an 80/64 inch choke. An oil water contact was found at -1831 meters subsea. Hydrocarbons were also discovered at the top of the Paleocene (Lower L. Balmei), testing at rates as high as 15.1 MMCFD and 580 BCPD of 52.1 degree API gravity condensate on a 40/64 inch choke. No oil/water contact was observed in the lower zone. Total reserves for both productive zones in the structure are estimated at 413 BCFG and 22.5 MMBC.

In December of 1985, 9 blocks surrounding the discovery were carved out as a location status (Attachment No. 1b). This status, which was renewed in 1987, expires on December 11, 1989. It is these 9 blocks which are being submitted for a Retention License.

GEOLOGICAL DISCUSSION

Regional Setting:

The eastern border of Australia (including Tasmania and the Bass Basin) is similar to the uplifted margin of many passive plate margins worldwide.

The Bass Basin was an intermontane basin during the late Cretaceous through the Eocene deposition of the Eastern View Coal Group and was isolated from marine environments by the Bassian Rise on the east and the Kind Island-Mornington High on the west.

In contrast, the Gippsland Basin opened into the Tasman Sea during the Late Cretaceous. Although most of the basin was undergoing non-marine Latrobe Group deposition through the Eocene, the eastern portions of the Gippsland Basin were gradually transgressed by coastal marine environments, after which rapid subsidence of the entire region resulted in the deposition of marine shales and carbonate. Not until the latest Eocene was the Bass Basin similarly transgressed by marine environments.

Stratigraphy:

The oldest sedimentary section penetrated in the Bass Basin is the Early Cretaceous Otway Group, thought to rest unconformably on Mesozoic and Paleozoic basements (see Attachment No 2). The Otway group is composed of non-marine clastics, which are poorly sorted, lithically immature, and are interbedded with thin coal seams. Vessicular olivine basalt is seen overlying the Otway section in the Durroon well.

The Otway section is overlain by the Late Cretaceous to Eocene non-marine Eastern View Coal Measures. The contact between the Otway and Eastern View Coal Measures has not been penetrated in the central basin, but is represented by a lower and middle Late Cretaceous unconformity to the southeast of the central basin.

The Eastern View Coal Measures is composed of interbedded sandstone, siltstone, shales, volcanics, and coals. The sand rich section shows no lithologic change within the shallower N. Asperus, P. Asperopolus, M. Diversus and L. Balmei palynologic intervals, with the exception that coal beds are more common and individual coal bed thickness is much greater within the P. Asperoplous interval. This repetitious character of the Eastern View Coal Measures make correlations in the basin difficult.

Extrusive volcanics are also found throughout the Eastern View Coal Measures section. The extrusive volcanics are often seen interbedded with clastics. The thickest interbedded volcanic section is seen within the Paleocene and Late Cretaceous sections.

Amoco's study of conventional cores from various Bass Basin wells which penetrated the Eastern View Coal Measures, suggests that the environment of deposition during that interval is primarily lower and upper delta plain, lacustrine, and estuarine with intermittent marine incursions.

Overlying the Eastern View Coal Measures are the Demon's Bluff carbonate-rich, shaley siltstone and the Troquay Group marine shales and marls.

Reservoir Rocks:

The predominantly non-marine sands of the Eastern View Group should be good to excellent reservoirs in the Yolla area. A single conventional core and log analysis indicate porosities average 25% in the upper pay zone in Yolla-1 and 17% in the lower pay zone. Attachment Nos. 3a and 3b detail the conventional and side wall core analyses and Appendix No. 1 details the log analysis.

Permeabilities calculated from drill stem tests (DST) in the Eastern View pay sections range from 16 md. (upper zone) to 308 md. (lower zone). Reservoir continuity may be restricted laterally or vertically though, as is the case in the Pelican area.

Only the upper part of the middle Eocene of the Bass Basin contains sandstone reservoirs deposited in a coastal complex similar to that containing over 90% of the oil discovered in the Gippsland Basin.

Source Rocks:

No evidence exists which demonstrates a firm correlation between Yolla hydrocarbons and their possible source section. Amoco's thermal modeling indicates that the present-day oil window is within the lower Eocene M. Diversus section in the central Bass Basin. The pre-Eocene section is in the present-day gas window adjacent to the Yolla structure. This may indicate a pre-Eocene source section for the Yolla hydrocarbons, which are predominantly gas.

Migration Pathways:

In the Gippsland Basin, mature oil source rocks are generally considered to be Upper Cretaceous coals and/or carbonaceous shales of the Latrobe Group. In the Bass Basin, gas-condensate tested in non-marine sandstones of the Lower Eocene in Pelican and Upper Paleocene of Yolla suggest some coaly or lacustrine petroleum source rocks are present.

However, whether these source rocks are of sufficient quality and quantity to generate commercial quantities of liquid hydrocarbons is questionable.

Extrusive basalts within the Paleocene section, if laterally extensive, may be barriers to hydrocarbon migration from Paleocene or older source rocks to reach younger Eastern View reservoirs. However, at Yolla the proximity of older well-defined graben-edge faults may have allowed significant near vertical migration into a Yolla structure that was already forming when these rocks were expelling hydrocarbons. Because of this near vertical migration path, it is believed that hydrocarbons have not been preferentially trapped in one side or other of the fault traversing the structure.

Seals:

Within the Yolla structure, effective vertical seals are provided by intraformational shales within the Eastern View Group and by the overlying Demon's Bluff shales. It is thought possible that faults cutting across the Yolla structure may provide an effective lateral reservoir seal since fault throws are generally greater than individual pay sand thicknesses in the Lower L. Balmei section.

Amoco's 1988 Bass Basin Marine Geochemical Survey traversed the Yolla structure, finding no anomalous hydrocarbon levels. This could be interpreted to mean that Yolla is very effectively sealed, or that faults or fractures do not intersect the sea floor or were not leaking during the survey period.

GEOPHYSICAL DISCUSSION

Data Acquisition:

The 1985 vintage seismic data (TQH) over the Yolla structure was acquired using a 1.5 by 2 km. grid. Dip line orientation was chosen so as to be perpendicular to structural strike.

The data were acquired with optimum source array and cable length to achieve good energy penetration of the Eastern View section. State of the art seismic processing procedures were used to enhance deep primary reflectors. These included velocity filtering and F-K domain multiple attenuation techniques. This resulted in fair to good quality seismic data which permitted detailed time-structure mapping of the Yolla area at the Top Eastern View, Paleocene, and mid-Eocene horizons.

Structural Interpretation:

The interpretation of the 1985 survey (TQH) over the Yolla structure was conducted on a Landmark interpretive workstation. The interpretation was transferred onto migrated stack sections for display purposes. Time structure maps were made on the Top Eastern View Coal Measures and the Paleocene Lower L. Balmei (as seen in Yolla-1) and are included as Attachment Nos. 4 and 5. Depth structure maps of these horizons (Attachment Nos. 6 and 7) were made by using a direct time to depth conversion of velocities taken from the Yolla-1 VSP. Because of the quality of the data, the time structure maps should be considered good to fair and fair to poor in reliability for the Top Eastern View Measures (EVCM) and Lower L. Balmei maps, respectively. The depth maps should be considered of similar reliability except in the vicinity of the intersection of seismic Lines TQH 211 and TQH 203 (Attachment Nos. 8 and 9).

In this area, high velocity Miocene volcanics (between 0.8 to 1.1 seconds) create an anomalous time structure high below 1.1 seconds. In 1965, Esso drilled through a seismically identical feature at the nearby Bass-1 well (see TQH 81, SP 530, Attachment No. 10). This well encountered volcanics between 773 meters and 942 meters, that had velocities, as measured by the BHC sonic log, ranging from 2,700 to 3,600 meters per second. In contrast, the surrounding shales, as seen in the Yolla-1 VSP, have velocities of approximately 2,100 meters per second. The inability to calculate the lateral and vertical velocity variations within these features, from seismic stacking velocity analysis, precludes the use of more rigorous depth conversion techniques. Because of the velocity pullup, portions of the depth structure maps have been annotated as unreliable.

Seismic Lines TQH 204 and 208 (Attachment Nos. 11 and 12) are included as examples of seismic lines that are dip and strike, respectively, to the mapped structure.

The primary fault trends for this area are in a northwest-southeast direction with a secondary north-south component. The north-south trending faults are the more recent and occurred during the late Eocene. The northwest-southeast trending faults occurred during the early to middle Eocene. The timing of the fault trends is illustrated on Line TQH 204 (Attachment No. 11). The north-south trending faults cross TQH 204 at shotpoints 250-300 and cut through the Top Eastern View Coal Measures. The northwest-southeast trending faults cross Line TQH 204 at shot points 150-200 and cut through the Lower M. Diversus. Expansion on the faults occurs downthrown and south-east of the Yolla structure. Minor M. Diversus and L. Balmei interval expansion is observed northeast of the structure.

Areal closure above the oil/water contact, highlighted in red on the Top Eastern View Coal Measures map, is approximately 1,700 acres (Attachment No.7). Log analysis indicate the oil/water contact is at -1831 meters subsea for an estimated 30 meters of hydrocarbon column. The areal closure highlighted in red on the Lower L. Balmei map is approximately 7,600 acres with an estimated 250 meters of vertical closure. Since no oil-water contact was found at this level, a hydrocarbon column of at least 235 meters is suggested by the log analysis.

RESERVE ANALYSIS

Reserves for both the lower and upper intervals were determined using a volumetric calculation as shown in Attachment No. 13. The upper zone, which is underlain by a small oil rim and a water leg, is calculated to contain 22 BCFG and 6.5 MBC: the lower zone contains the bulk of the total reserves with 391 BCFG and 16.0 MBC. A detailed discussion of the input parameters and the calculations follow.

PARAMETERS

Area:

The productive acreage was planimetered from the structure maps on the Top Eastern View Coal Measures map for the upper zone and the L. Balmei for the lower. The areal extent of the upper zone was determined by the oil-water contact and was calculated to be 1703 acres. Since no oil-water contact was observed in the lower zone, the area of structural closure was assumed to be the productive acreage and was measured to be 7615 acres.

Thickness:

Log analysis of the Yolla-1 was employed to determine the net pay for both zones. For the evaluation, the interval from 1775 to 3000 meters was selected for detailed analysis since it covers the entire productive length in the well. This interval was then evaluated as three separate zones: zone 1 extends from 1775-2145 meters; zone 2 extends from 2145-2565 meters; and zone 3 extends from 2565-3000 meters. Only zones 1 and 3 were determined to contain hydrocarbons. Basalt was encountered shortly below this interval at 3031 meters negating the need to extend the analysis any deeper. An in-depth discussion of the calculations, techniques, and results is included as Appendix No. 1.

A net thickness of 10.5 meters was calculated for the upper interval. Pay cutoffs of a maximum water saturation of 60%, maximum shale volume of 40%, and a minimum porosity of 10% were applied to obtain the net pay value from a gross interval of 50.25 meters. However, a thickness of 10.0 meters was used for the reserve calculations since completion of intervals less than 2 meters was considered both operationally impractical and less likely to remain continuous over the entire structure. For the lower zone, a net thickness of 25.75 meters was calculated using a porosity cutoff of 10%, water saturation cutoff of 40%, and shale volume cutoff of 40%. If only intervals of at least 2 meters are considered viable completion zones, then 2.75 meters of the total thickness is eliminated. Again, to ensure that only the pay that can practically be produced is incorporated into the reserve calculation, a thickness of 23.0 meters was used. Although some intervals appear to have a high water saturation (greater than 70%) as a result of the high quantity of fines in the sands, no definite oil-water contact was observed.

Because of the gradation in saturation from gas to oil in the upper zone, it is difficult to definitively discern the location of the gas/oil contact for reserve calculation purposes. For this reason, the upper zone pay was not segregated into a gas thickness and an oil thickness.

Porosity and Water Saturation:

Average porosities of 25% and 17% for the productive portion of the upper and lower pay zones respectively were calculated. These porosities were derived from the log analysis using corrected values from both the neutron and density logs. A detailed discussion of these calculations is contained in Appendix No. 1.

Water saturations were likewise calculated from the log analysis of Yolla-1 and are documented in Appendix No. 1. Average water saturations of 49% for the upper and 30% for the lower zones were used. An oil-water contact was observed at the log depth of 1842 meters (1831 meters subsea).

To correct the reserve calculation for the large amount of CO_2 present, the lower zone hydrocarbon pore space was reduced by 19.5%. Likewise, the upper zone was reduced by 7.5%. These percentages were determined from the fluid analysis.

Gas Volume Factor:

The formation volume factor was calculated using the ideal gas law relationship between volume, temperature, and pressure. The calculation is shown on the next page:

$$Bg = \frac{35.35p}{zT} \text{ SCF/cu ft}$$

Where:
Bg = gas volume factor
p = reservoir pressure, psi
T = reservoir temperature, degrees Rankin
z = gas deviation factor

$$Bg = \frac{35.35\ (4200)}{(0.903)752} = 219\ \text{SCF/cu ft}$$

The fluid analysis was used to determine the pseudoreduced temperature and pressure. From this, z was calculated using Standing-Katz correlations (Attachment No. 14).

Recovery Factor:

The recovery factor is expected to vary between the two zones because of the different drive mechanisms present in each. Volumetric drive was assumed for the lower zone since no oil-water contact was observed and no significant water production was seen during the DST. Generally, volumetric drive gas reservoirs are able to recover 80% to 90% depending on the abandonment pressure. In the case of Yolla, a recovery factor of 85% was used for the lower zone based on both the depletion study performed by Core Lab (Attachment No. 15) and that calculated by the simulation program used for projecting deliverabilities. An abandonment pressure of 500 psi was assumed for the calculations. The simulation program is discussed in more detail on page 13.

The upper zone is believed to be water drive and, as such, will have a substantially reduced recovery factor. Agarwal, Al-Hussainy, and Ramey[1] demonstrated that recovery factors for such reservoirs can be as low as 45%. Similarly, Chierici, Cuicci, and Long[2] found that reduced recoveries could be expected for gas reservoirs under water drive, however they did not find recovery factors as low as Agarwal. With no production history to accurately assess the effect of the aquifer, a more conservative approach was taken and a recovery factor of 40% assumed. Even if recovery was assumed to be as high as in the lower intervals, the reserves associated with this zone are an extremely small percentage of the total (less than 5%). Therefore, a large change in the upper zone recovery factor will not significantly impact total field recovery estimates.

Results:

Total field reserves were calculated to be 413 BCFG and 22.5 MMBC. As previously mentioned, the bulk of this lies in the lower zone with 391

BCFG and 16 MMBC. Condensate reserves for the lower zone were based on condensate yields obtained from the drill stem test of 41 Bbl/MMCFG.

Upper zone reserves of 22 BCFG and 6.5 MMBC were determined in a similar method. The liquids yield was again obtained from the actual results of the DST. As discussed above, the well log showed a transition in saturation from gas to oil making determination of a definite oil/gas contact difficult. Therefore, no accurate differentiation can be made between liquids reserves from the bottom of the interval and the condensate from gas.

Operationally, it is beneficial to complete the well so that the maximum contribution to the total wellstream comes from the gas portion of the interval. Since the crude has a high paraffin content, maximum dilution with non-waxy condensate is desirable. If the point above which only the gas with the lowest liquids yield present in the zone is picked as the gas-oil contact, then 8 of the 10 meters of pay would be considered oil bearing. (This point was determined from the logs after elimination of the shale effects.) For this case, the 'crude' reserves are calculated as only 9.4 MMBO; not enough to warrant any change in the development plan or affect the economics.

Because of the fault which runs through the middle of the lower zone, the reserves for this interval should technically be classified into both proved and probable categories. The southern portion of the field is considered proved (because of the presence of Yolla-1) and contains 118 BCFG and 4.8 MMBC. Probable reserves for the northern half are 273 BCFG and 11.2 MMBC.

Although categorized as probable on the other side of the fault, there is a high probability that hydrocarbons do exist there. At the western end of the structure, where the fault plays out, there is only a very small throw which increases the likelihood that hydrocarbon migration could occur through juxtaposed sands. Additionally, the section of the fault with the greatest throw (50 m) would place nearly all the sand intervals in juxtaposition across the fault (Attachment No. 16). Across the remainder of the fault, there is a high likelihood that at least some juxtaposition exists since the fault throw (less than 50 m) is significantly less than the gross pay interval of 235 m.

DELIVERABILITY

Wells:

To determine the number of wells required for development, consideration was given to the areal extent of the reservoir and continuity of producing intervals. Total areal extent of the reservoir of approximately 7600 acres was calculated. Because of the high permeability determined from the DST, well spacing of 1300 acres, or 6 wells, is believed to be capable of draining the reservoir. Continuity of the sands, however, is still unproven. To ensure that all contingencies are covered, the base case development plan is based on drilling at 650 acres or 12 wells.

Rates:

To calculate the deliverability of the wells, an in-house computer simulation program called Gas Well Simulation Program (GWSP) was utilized. This program predicts the producing rate and recovery factor for gas wells depending upon the completion design, surface pressures, hydrocarbon composition, and reservoir characteristics (ie permeability, original gas in place, test data, etc.) (Attachment No. 17). The program is designed for dry gas reservoirs under volumetric depletion such as exists in the lower interval. The rate prediction is highlighted in Attachment No. 18 which is a copy of the GWSP output for this zone.

Since the upper zone is believed to be influenced to some extent by the underlying aquifer, the program input was modified to adjust for this by inputting an original gas in place of only 40% of the actual. Although the prediction generated is not strictly precise (since liquid fallback is not completely accounted for), it yields satisfactory results. When the contribution of the upper zone is compared with the lower, it becomes apparent that the upper zone rates calculated by GWSP are within the accuracy of the overall evaluation. That is, a deviation in the upper zone rates by as much as even plus or minus 25% yields a deviation in the total field production of only plus or minus 1%.

Once individual well capabilities were established, the timing of their completion to satisfy the market demand was determined. This was accomplished by plotting producing gas rate versus cumulative production for a Yolla well on the same graph as the rate versus cum for the demand profile for Tasmania. Where the two curves intersect is the point at which the market requirements are not being met. Wells were then added to ensure the total field deliverability could exceed demand. Attachment No. 19 is the rate/cumulative production plot generated for this evaluation. It should be noted that gas sales to HECT and various industrial/commercial users will commence in 1997.

Initially, four wells will be completed to supply gas to the Tasmanian market. Two more wells will be added after 5 years, four more nine years after production commences, and the last two wells are drilled 15 years after the field goes on line. Not until the 21st year is the field unable to meet demand. The deliverability available with this drilling schedule will be sufficient to supply up to 100% of the additional energy demand profile predicted in the gas marketing report.

DEVELOPMENT

The facility and equipment design was prepared by the R.J. Brown-CMPS company in Australia with an adjustment by the Amoco Construction Group for the higher drilling density and landing at Bell Bay versus Stanley. Reserves, producing rates and market conditions were supplied for design of the platform, production equipment, and pipeline from the Yolla structure to shore. Although the Tasmania gas market demand profile used was a preliminary version, it is in close agreement with the final gas market study. The differences between the two profiles does not change the design. A copy of the R.J. Brown report is included as Appendix No. 2 and should be referred to for the details of the work.

Total development cost to install the platform, processing facilities, and pipeline is estimated to be A$347 MM. A detailed breakdown of these costs is provided in Attachment No. 20.

Platform:

Several options were considered for production of the Yolla reserves. Selection of the optimum development plan was based on using only technology which was accepted and proven for the environment. Additionally, the plan must provide a design which minimizes costs while providing adequate reliability and compliance with applicable codes and regulations.

Ultimately, a fixed steel platform with offshore compression and a single two phase line to shore was chosen. Consideration was also given to the following options:

(1) Subsea completions flowing to a production manifold, then through a line to shore.

(2) Subsea completions flowing to a subsea multiphase pump, then pumped to shore.

Both of the subsea designs were rejected since the technology to flow multiphase fluids over long distances is not yet proven and construction of multiphase pumps is only in the research and development stage.

The platform design is a four leg structure which utilizes a drilled and grouted pile technique for anchoring to the sea floor. This technique was chosen because of its suitability to the Bass Strait environment, as proven by its successful use in all of the Esso/BHP platforms. Two decks will be constructed and the total deck, jacket and pile weight for the platform will be 2320 tonnes.

Facilities:

To minimize platform size and operation and to maximize security of supply, maximum processing was placed on shore. Offshore facilities include a separator to remove water and well test equipment.

On land, facilities for additional water handling, liquids separation, liquids tank storage, CO_2 removal, and gas dehydration and metering are to be constructed. The CO_2 removal system will be either an Amine Unit or Benfield process plant. Gas dehydration will be accomplished with a Triethylene glycol plant. Water disposal will be through evaporation ponds.

Pipeline:

As with the platform selection, several options for transportation of the hydrocarbons to shore were considered.

(1) Construction of a single two phase line.

(2) Construction of two separate lines: one for gas and one for oil.

(3) Construction of one line to shore for dry gas and installation of an offshore storage tanker for liquids storage and transportation.

Options (2) and (3) were not pursued because of the significantly higher capital investment required. The line will be constructed to land near the Bell Bay plant to reduce total pipeline length and minimize onshore transportation. (It was assumed that any new gas fired power plant would be built near existing facilities to simplify tie-in to existing distribution systems.)

Once a single line to shore was established as optimum, an evaluation of whether compression should be provided onshore or offshore was undertaken. Although placement on land would minimize offshore facilities and operation, this would require that a larger diameter pipeline be installed. The increase in up front costs associated with the larger line was found to be great enough to more than offset the economic benefit of reduced operating costs over time if compression was on shore. Therefore, it was elected to install compression on the platform and reduce the line diameter. A table of these and other affected costs is summarized in Attachment No. 21.

Reentry of Yolla-1:

After completion of testing, the Yolla-1 well was temporarily abandoned on October 10, 1985. During abandonment operations, the 9 5/8 inch casing was cut at 329 feet subsea to prepare it for later reentry since it had been landed improperly. A diagram of the current wellbore condition is included as Attachment No. 22.

Reentry will be performed by the following steps:
1) Tie-back housing to platform.
2) Patch 9 5/8 casing and tie-back to surface.
3) Drill out cement plugs and clean out well.
4) Analyze 9 5/8 casing condition to determine if 7 inch casing should be run.
5) Run 7 inch casing, if necessary.

The cost estimate for reentry assumes that it will be necessary to set 7 inch casing to be sure all contingencies are covered.

Operating Cost:

Operating costs for Yolla were estimated by R.J. Brown as between $15.1 MM and $15.6 MM per year for the 1300 acre well spacing case. A detailed table of these costs is provided as Attachment No. 23. Since compression will be offshore, expenses are calculated assuming the platform will be manned. These costs are comparable to those estimated for the Gippsland Basin fields by the WoodMac service. For 1989 values, the equivalent operating cost applied to peak Yolla rates would be $10.0 MM per year (see Attachment No. 24). This calculation, however, assumes that gas is the only hydrocarbon produced at Gippsland. If the same numbers are generated on a BOE basis, then Yolla would calculate significantly lower at $2.9 MM per year. Although synergies of operation exist for the Esso/BHP fields, the calculation still indicates that the operating cost estimated for Yolla is reasonable.

For the base case economics, which involves drilling twice as many wells, the operating cost was increased to between $16.1 MM and $17.1 MM per year. All of this increase is a result of a doubling of the repair well expense and increasing the variable portion of platform operations by 25%.

GAS MARKET

As with the construction design, an indepth review of the Tasmanian gas market was undertaken by the consulting firm of P.M. Garlick in conjunction with SAGASCO. The report reviews the current energy supply situation in the state, predicts future requirements, and addresses the role of gas in meeting these future needs. The report is provided as Appendix 3 and should be referred to for details of the analysis.

Even without the addition of a significant number of new industrial users, the study shows that there will be a shortfall in energy supply in the 1990's. Because of the long lead time required, new hydro projects must be authorized in the immediate future or this shortfall will have to be addressed by an alternate form of energy.

Current Supply and Users:

Currently, 99% of Tasmania's electrical energy needs are met through hydro power generation. Total current generating capacity is 2,316 MW, of which 2,076 is supplied by five hydro schemes. The remaining 240 MW capacity is available in the Bell Bay fuel oil powered plant on the northern shore of the island. This plant is used for back-up electricity generation only in times of extended drought. A summary of the hydro and thermal schemes with their associated power stations and capacity is included as Attachment No. 25.

Two additional hydro projects are currently under construction, King River and Anthony, and are scheduled for completion in 1992 and 1994, respectively. King River will add 144 MW and Anthony will add 83 MW of capacity to the system, bringing the total to 2,543 MW by 1994.

Industrial consumers are the largest user of power in Tasmania and accounted for two-thirds of the total energy sales in 1988 of 8,119 GWh (see Attachment No. 26). Presently, there are 18 major industrial users and most are centered in the northern coastal area. Nearly all of them are dedicated to Tasmania's natural resource base: timber and timber products, mineral processing, and agriculture.

Domestic and commercial energy use comprise the remainder. Their level of consumption is closely related to seasonal weather patterns. With the exception of 1988, these markets have increased every year over the last decade.

Future Energy Consumption:

The HECT's most recent load forecast predicts that electricity consumption will grow at an average annual rate of 1.53%. At this rate, additional generating capacity will be required by 1997 (see Attachment No. 27). This prediction is based on historical increases and does not incorporate the addition of any major new industries. For the purpose of the Retention Application work, the addition of new industrial users was not included in the sales profile since their addition is purely speculative at this point.

To generate the sales profile, Yolla gas was assumed to supply HECT with approximately 10 PJ/Yr. with the remainder representing supplemental sales to the various industrial/commercial/domestic users.

Beyond increased power generation, several possibilities exist for increased gas usage above the HECT forecast. These include the use of natural gas for transportation fuels and as a feedstock for ammonia manufacturing. Additionally, conversion of older boiler units to a gas fueled system in industrial plants could result in increased demand. Although no allowance for any of these possibilities was included in the Application work, they are mentioned since the need for gas may become more urgent than is implied in the forecast used.

Cost and Implementation Comparison:

A comparison of the energy cost of natural gas with existing and other potential forms of energy supply to Tasmania was made. The study indicated that if used for generating electricity on a Frame 9 gas turbine, the breakeven cost of gas compared to hydro is $5.50/GJ. This price also compares favorably to the high energy costs of alternative fuels as shown below:

Coal	$2.20 per GJ
Fuel Oil	$5.90 to $7.00 per GJ
Diesel	$13.20 per GJ
LPG	$13.50 to $16.80 per GJ

Only coal was found to be lower cost. However, environmental concerns coupled with Tasmanian coal's reduced utility from the high ash content may preclude it as an alternative to other fuels. Also, if the costs associated with the handling, stockpiling, and ash disposal were included, then it may not be as attractive as the above prices appear.

When compared to other forms of electricity generation, gas also allows greater flexibility because of the shorter lead time required for construction of a gas fired turbine plant and reservoir development. It is estimated that three years would be required to build a gas plant; this compares to seven years for coal and nine years for hydro powered plants.

ECONOMICS

To determine commerciality of the structure, the economics for development were calculated. The assumptions used and the results are discussed below. A summary of the assumptions and results is included as Attachment No. 28 and the input/output of the economic evaluation appears in tabular form as Attachment No. 29.

Assumptions:

Included in Appendix 3, "An Analysis of the Market Potential for Natural Gas", is the report prepared by the P.M. Garlick consultants which indicates that gas is a competitive fuel if used by HECT for power generation. If Yolla supplies the energy requirements to HECT and industrial/commercial users at the levels discussed previously, an average price for gas produced of approximately $5.00/ GJ can be assumed for the economic evaluation. Also, a 1990 price for produced liquids of $21.00/Bbl is used and is representative of current prices for liquids with similar properties.

Of course, any sales contracts will need to take into account a number of different aspects, such as: modulation, buildup periods, take or pay clauses, guarantees, the selling point of the gas (eg whether the gas is sold at the onshore processing facilities or the point of use), date of initial sales, etc. All of these will have an impact on the sales price and are still unknown. It must also be noted that the economics are based on a production profile which assumes a baseload HECT gas volume of at least 10 PJ/Yr. and a significant volume of additional sales to other end users. A reduction in the guaranteed takes by HECT would adversely affect the minimum price which must be received to proceed with development.

Capital investment and operating costs were input as discussed previously. Abandonment costs are assumed to be incurred in the last year of production. Attachment No. 29 shows the timing of the investments and expenses. Costs are escalated at the assumed Australian inflation rate of 8% per year and prices are escalated at 8%/Yr and 4%/Yr for gas and liquids, respectively. In addition, Overhead is assumed to be 4.5% of total expenditures per year.

Australian fiscal terms include a profits-based Resource Rent Tax (RRT). Under RRT, cumulative project costs less revenues are compounded forward at a 'threshold rate' (15% plus the Australian Commonwealth 15-year long-term bond rate). For this analysis, a 28% threshold rate was assumed throughout the project life. When revenues ultimately exceed project costs plus the threshold rate of return, additional profits are taxed at 40%. Due to the magnitude of past expenditures in the license area, the RRT threshold limit is not exceeded and, therefore, RRT is assumed not to be applicable.

Capital items are depreciated for Australian income tax purposes on a ten-year straight line basis starting in the first year of revenue. The Australian corporate income tax rate is 39%. It is also assumed that tax deductions for the abandonment costs would be available. For this analysis, the tax loss carryforward balance, which was generated by past expenditures, is assumed to be unavailable.

Results:

The final year of production occurs in the year 2025, when an economic limit is reached (costs exceed revenues). The cumulative undiscounted cash flow in the last year of production is A$4977 MM with an internal rate of return of 20%. Positive yearly cash flow is generated in the first year of production and cumulative positive cash flow (payout) occurs in the year 2003, 9.5 years after the project begins.

These results show that profitable economics are generated to participants of License T/14P at a gas price which is also attractive when compared to alternative fuels.

WORK PROGRAM

At present, the greatest degree of uncertainty associated with the development of Yolla lies with the timing of the need for gas energy in Tasmania. The participants of Yolla plan to continue to closely monitor the marketing situation to identify at the earliest date possible when development may begin. As soon as is practically feasible, the participants will also actively pursue firm commitments for the sale of Yolla gas.

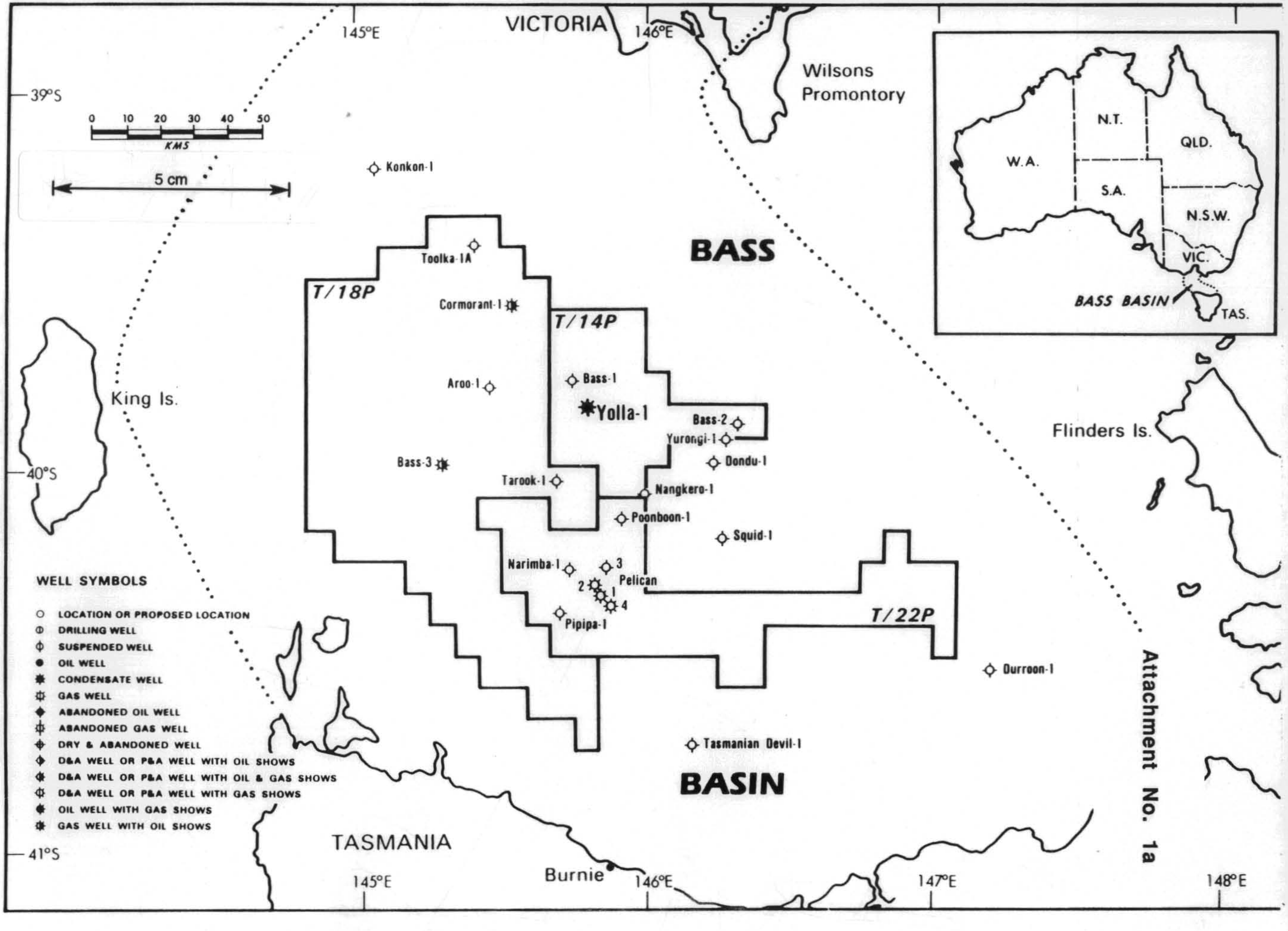
The terms of any contract negotiated may include the requirement to drill an appraisal well to confirm reserve estimates and deliverability calculations. With the current level of confidence in the potentially conservative reserve calculation, we do not forsee a need to provide for drilling in the work program, but rather, it should result as a natural outcome of gas sale contract negotiations.

ATTACHMENTS

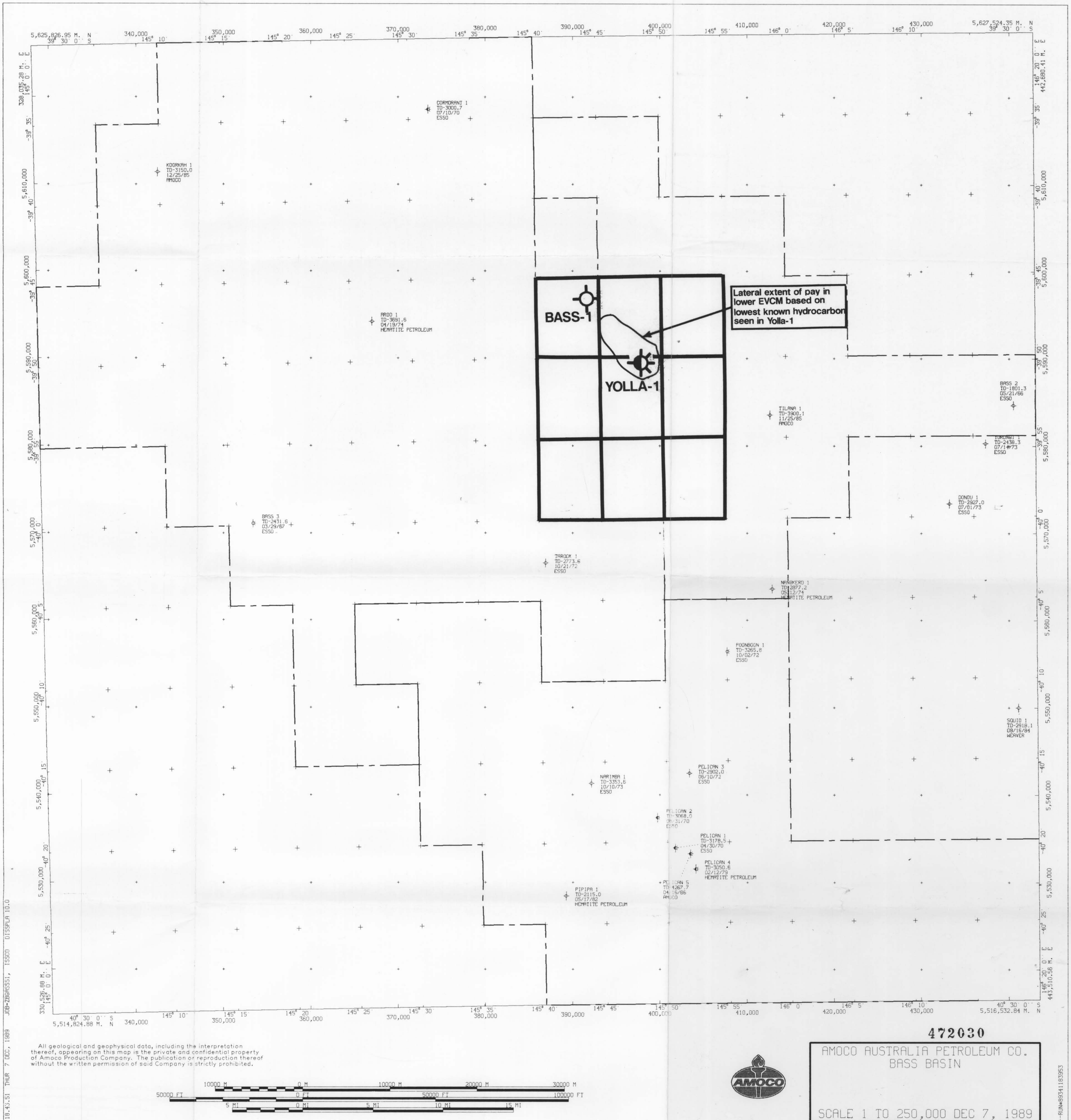
No.	**Description**
1a	Location Map
1b	Retention Blocks Map
2	Stratigraphic Column
3a	Conventional Core Analysis
3b	Sidewall Core Analysis
* 4	Time Map of the Top Eastern View Coal Measures
* 5	Time Map of the L. Balmei
* 6	Depth Map of the Top Eastern View Coal Measures
* 7	Depth Map of the L. Balmei
* 8	Seismic Line TQH 211
* 9	Seismic Line TQH 203
* 10	Seismic Line TQH 81, SP530
* 11	Seismic Line TQH 204
* 12	Seismic Line TQH 208
13	Yolla Reserves Calculations
14	Yolla Z-Factor Calculation
15	Core Lab Depletion Study, Yolla-1 DST No. 1
16	Juxtaposition Panel
17	GWSP Program Parameters
18	GWSP Output-Lower Zone
19	Yolla Delivery vs Tasmania Market Demand Plot
20	Yolla Development, Capital Costs Table
21	Cost Comparison, Onshore Compression vs Smaller Diameter Pipeline
22	Yolla-1 Temporary Abandonment Wellbore Diagram
23	Yolla Operating Cost Table
24	Gippsland Basin Operating Cost Comparison to Yolla Estimate
25	Table of Tasmanian Power Plant Capacity
26	Table of Historical Tasmanian Power Sales
27	Tasmania Gas Demand Profile
28	Summary of Economic assumptions and results
29	Table of economic input and output by year
30	Abbreviations Listing
31	References

* DENOTES : Attachments 4 through 12 provided in draft copy of Application Text.

472029



Attachment No. 1a



All geological and geophysical data, including the interpretation thereof, appearing on this map is the private and confidential property of Amoco Production Company. The publication or reproduction thereof without the written permission of said Company is strictly prohibited.

UNIVERSAL TRANSVERSE MERCATOR MPC CM55
SPHEROID = 16
CENTRAL MERIDIAN = 147° 0' 0'' E LON SCALE FACTOR = 0.99959999

PLOT 1 18.43.51 THUR 7 DEC, 1989 JOB-ZBGASS51, ISSCO DISSPLA 10.0

472030

AMOCO AUSTRALIA PETROLEUM CO.
BASS BASIN

SCALE 1 TO 250,000 DEC 7, 1989

5 cm

Attachment No. 1B

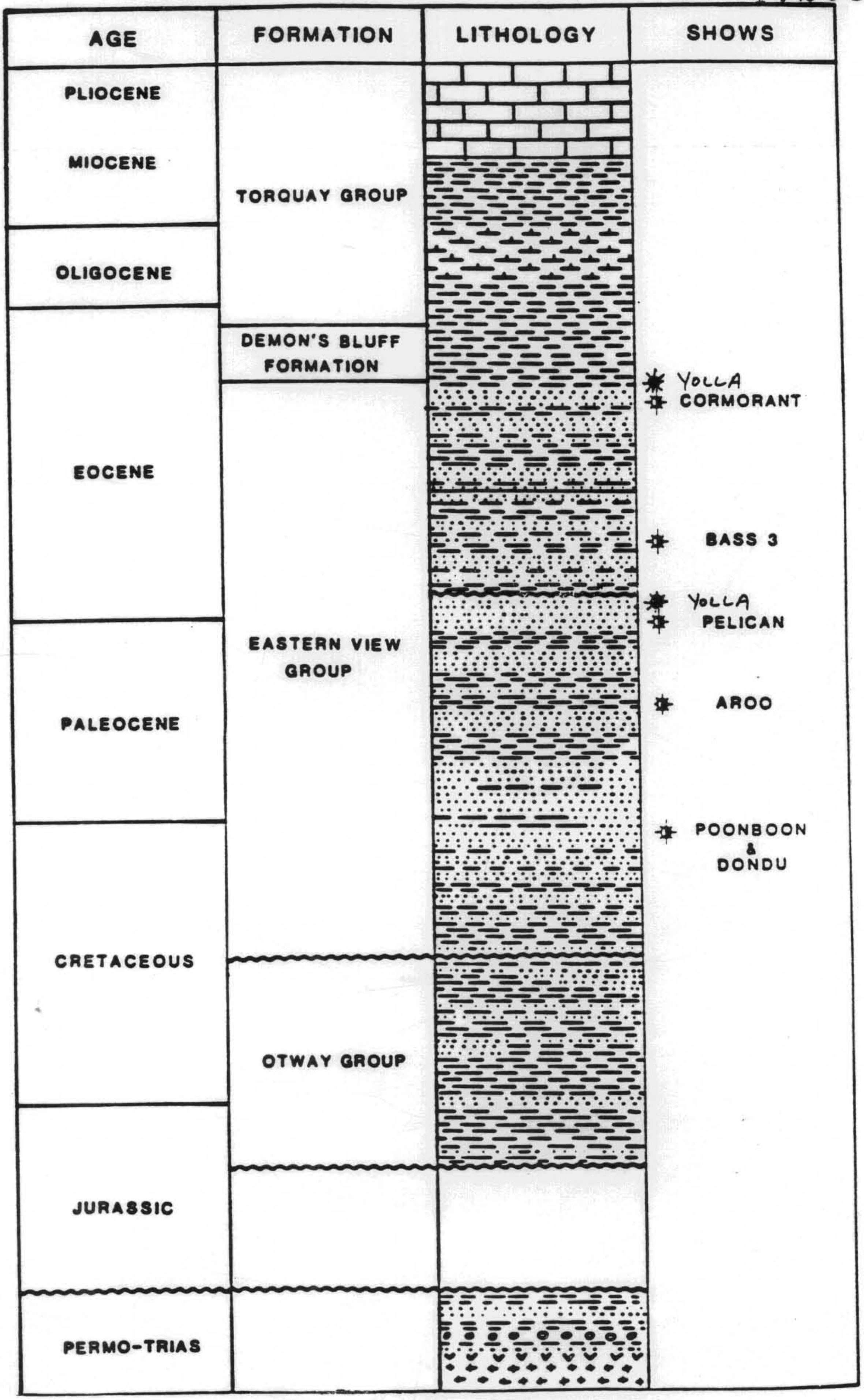
ZBGASSSA--RUN=89341183953

5 cm

Attachment No. 2

472031

BASS BASIN
GENERALIZED STRATIGRAPHY



CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

472032

CORE ANALYSIS REPORT

FOR

AMOCO EXPLORATION

YOLLA NO. 1
YOLLA
VICTORIA

Attachment No. 3a

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

AMOCO EXPLORATION
YOLLA NO. 1
YOLLA
VICTORIA

DATE : 17/7/85
FORMATION :
DRLG. FLUID:
LOCATION : BASS BASIN

FILE NO : ADCA 85013
LABORATORY: ADELAIDE
ANALYSTS : RM;OOI
ELEVATION :

CONVENTIONAL CORE ANALYSIS

CORE NO. 1

API 97-035-03789-00

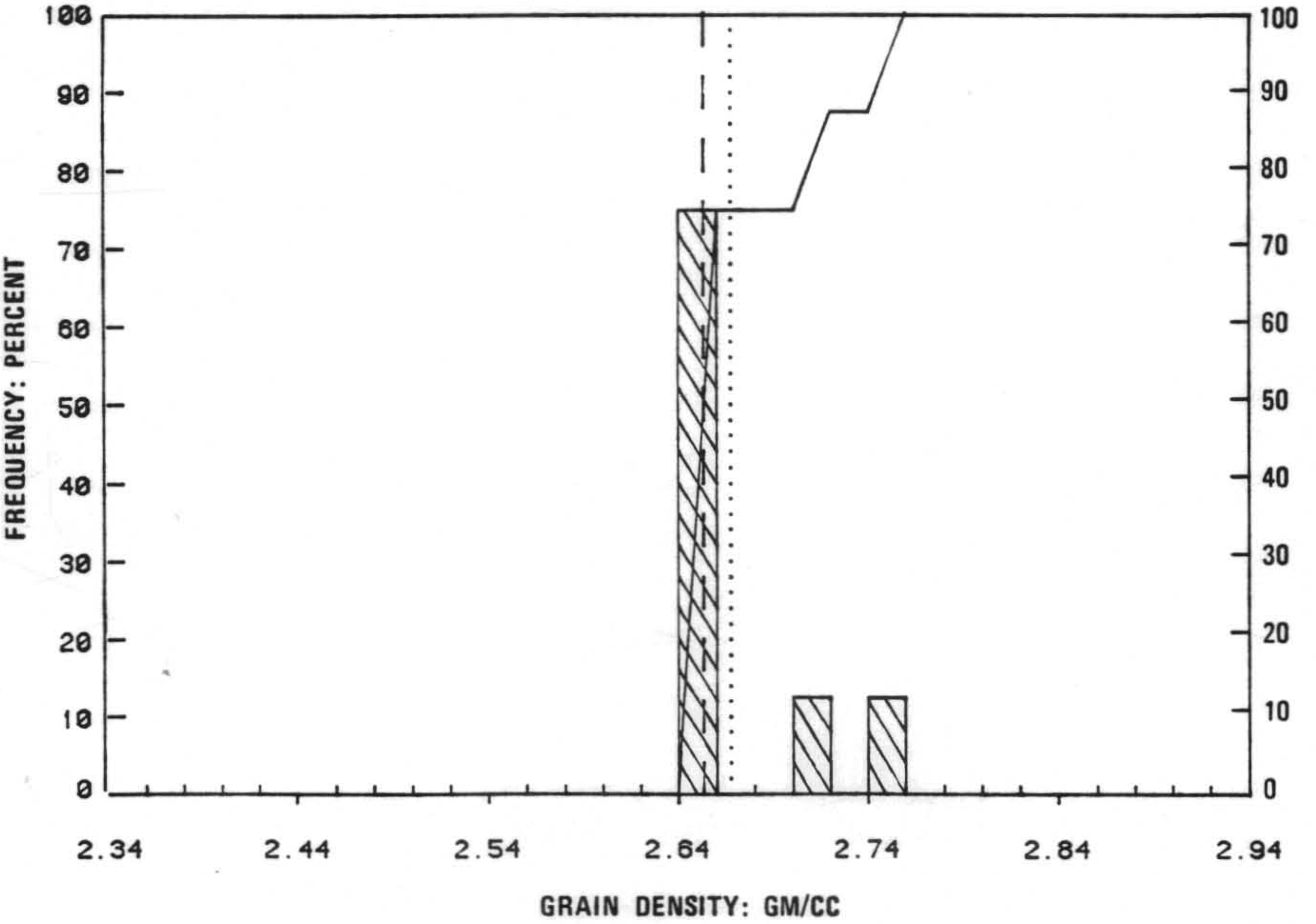
SAMPLE NUMBER	DEPTH FEET	PERM MD HORIZ Ka	FLD POR	He POR	OIL% PORE	WTR% PORE	GRAIN DEN M	DESCRIPTION
1	6055.0	75.	31.1	29.6	12.5	84.8	2.65	LEAD SLEEVE
2	6056.0	17.	23.1	25.2	11.1	81.3	2.70	SST BRN/GY VFG FRM SBANG-SBRND WL SRT ABD ORG DETR MAT CARB SPK V SLTY MIC MIC
3	6057.0	11.	31.2	25.8	4.3	90.6	2.65	SST BRN/GY VFG FRM SBANG-SBRND WL SRT CARB INCL V SLTY MIC MIC I/P
4	6058.0	65.	28.7	30.4	5.6	88.3	2.65	SST BRN VFG FRM SBANG-SBRND WL SRT OCC CARB SPK SLTY MIC MIC
5	6059.0	51.	27.7	30.0	5.0	88.5	2.74	SST BRN VFG FRM SBANG-SBRND WL SRT OCC CARB SPK SLTY MIC MIC I/P
6	6060.0	37.	31.0	29.2	3.7	90.5	2.65	SST LTGY/BRN VFG FRM SBANG-SBRND WL SRT MNR CARB INCL V SLTY MIC MIC I/P
7	6061.0	42.	28.0	30.0	4.6	86.2	2.65	SST LTBRN/GY VFG FRM SBANG-SBRND WL SRT MNR CARB INCL SLTY MIC MIC
8	6062.0	204.	29.8	30.9	4.2	79.9	2.65	LEAD SLEEVE
9	6063.0		26.1		4.1	71.8		BROKEN CORE
9A	6063.0		31.0		2.8	87.7		BROKEN CORE

472034

CORE LABORATORIES, INC. *Petroleum Reservoir Engineering*

COMPANY AMOCO EXPLORATION FILE NO. ADCA 85013
WELL YOLLA NO. 1 DATE 22/7
FIELD YOLLA FORMATION ELEV.
COUNTRY VICTORIA DRLG. FLD. CORES
LOCATION BASS BASIN

GRAIN DENSITY HISTOGRAM



LEGEND
ARITHMETIC MEAN GRAIN DENSITY ....
MEDIAN VALUE — — —
CUMULATIVE FREQUENCY ———

5 cm

STATISTICAL DATA FOR GRAIN DENSITY HISTOGRAM

COMPANY: AMOCO EXPLORATION
FIELD : YOLLA
WELL : YOLLA NO. 1
COUNTRY : VICTORIA

GRAIN DENSITY : gm/cc (MEASURED) RANGE USED 2.34 TO 2.94

DEPTH LIMITS : 6055.0 - 6099.8 INTERVAL LENGTH : 44.8
FEET ANALYZED IN ZONE : 10.0 LITHOLOGY EXCLUDED : NONE

DATA SUMMARY

GRAIN DENSITY ARITHMETIC MEAN	GRAIN DENSITY MEDIAN
2.67	2.65

STATISTICAL DATA FOR GRAIN DENSITY HISTOGRAM

COMPANY: AMOCO EXPLORATION
FIELD : YOLLA

WELL : YOLLA NO. 1
COUNTRY : VICTORIA

GROUPING BY GRAIN DENSITY RANGES

GRAIN DENSITY RANGE	FEET IN RANGE	AVERAGE DENSITY	FREQUENCY (PERCENT)	CUMULATIVE FREQUENCY (%)
2.64 - 2.66	6.0	2.65	75.0	75.0
2.70 - 2.72	1.0	2.70	12.5	87.5
2.74 - 2.76	1.0	2.74	12.5	100.0

TOTAL NUMBER OF FEET = 8.0

PERMEABILITY VS POROSITY

COMPANY: AMOCO EXPLORATION
FIELD : YOLLA

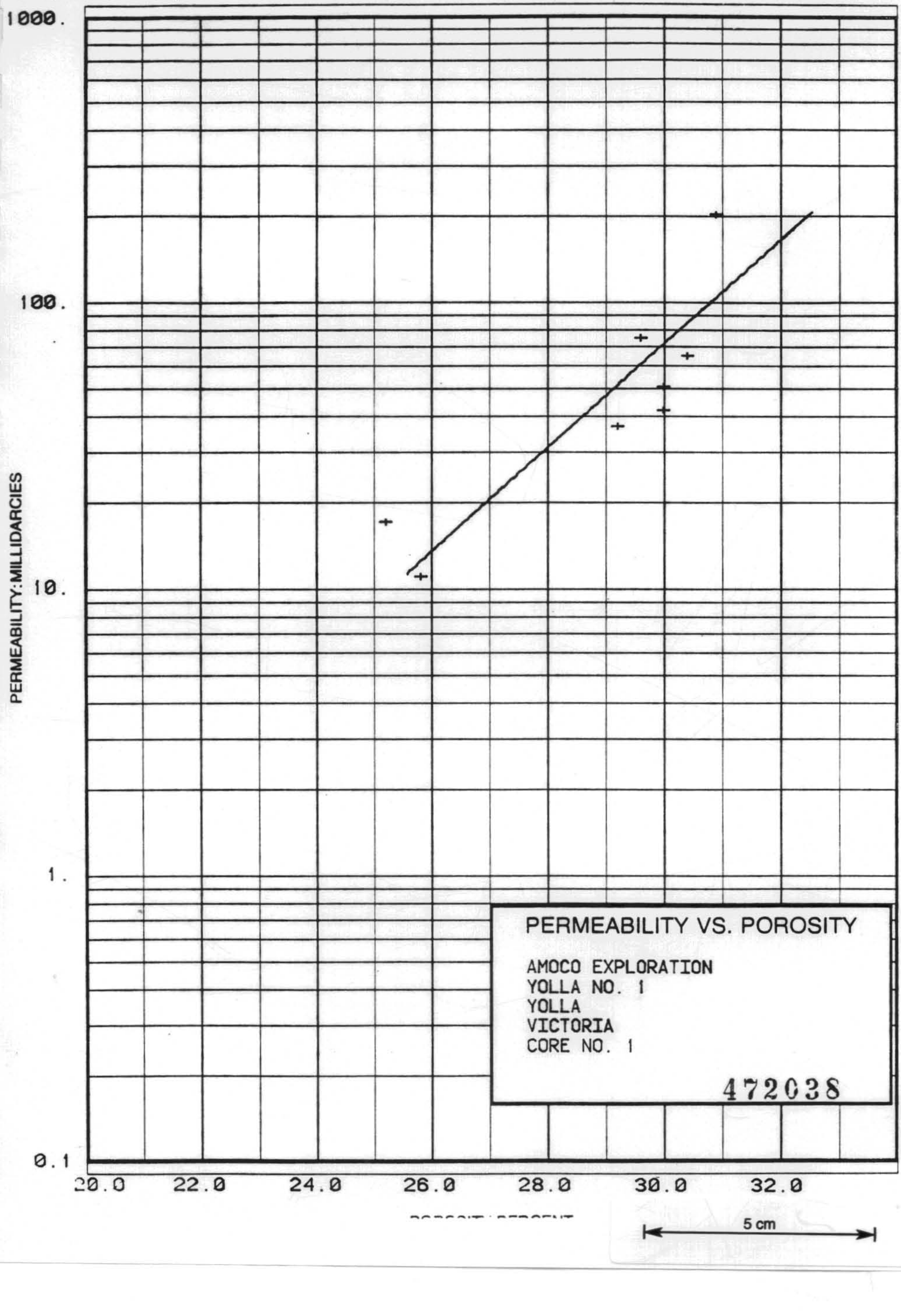
WELL : YOLLA NO. 1
COUNTY, STATE: VICTORIA

AIR PERMEABILITY : MD - HORIZONTAL (UNCORRECTED FOR SLIPPAGE)
POROSITY : PERCENT (HELIUM)

DEPTH INTERVAL	RANGE & SYMBOL	PERMEABILITY MINIMUM	PERMEABILITY MAXIMUM	POROSITY MIN.	POROSITY MAX.	POROSITY AVERAGE	PERMEABILITY AVERAGES ARITHMETIC	HARMONIC	GEOMETRIC
6055.0 - 6099.8	1 (+)	11.000	204.0	25.2	30.9	28.9	63.	32.	44.

EQUATION OF REDUCED LINE RELATING PERMEABILITY(K) TO POROSITY :
LOG(K) = (SLOPE)(POROSITY) + LOG OF INTERCEPT
K = ANTILOG((SLOPE)(POROSITY) + LOG OF INTERCEPT)

RANGE	EQUATION OF THE LINE
1	PERM = ANTILOG((0.1813)(POROSITY) + -3.5899)

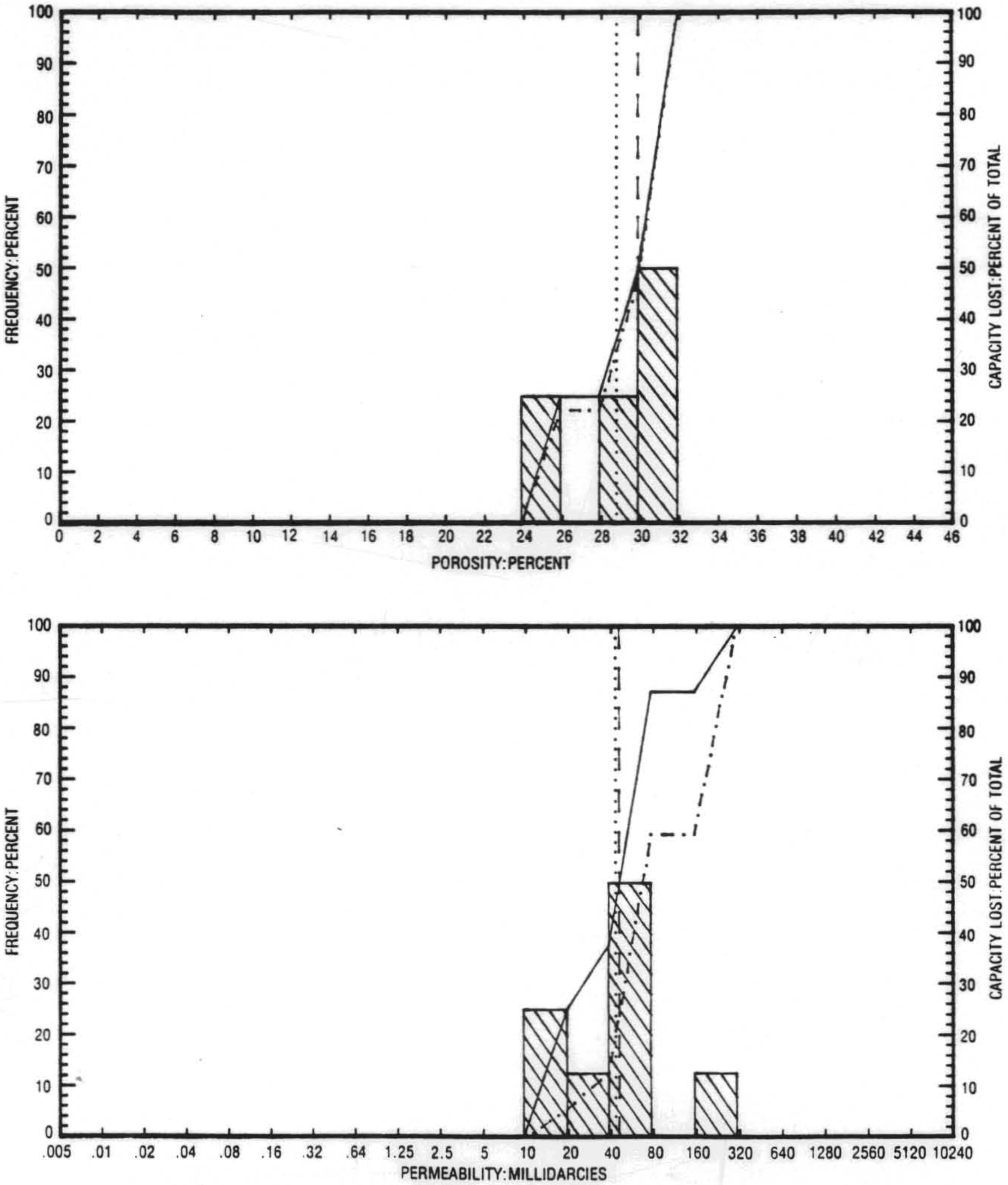


PERMEABILITY VS. POROSITY

AMOCO EXPLORATION
YOLLA NO. 1
YOLLA
VICTORIA
CORE NO. 1

472038

5 cm



PERMEABILITY AND POROSITY HISTOGRAMS

AMOCO EXPLORATION
YOLLA NO. 1
YOLLA
VICTORIA
CORE NO. 1

LEGEND

ARITHMETIC MEAN POROSITY ············
GEOMETRIC MEAN PERMEABILITY ············
MEDIAN VALUE — — —
CUMULATIVE FREQUENCY ———
CUMULATIVE CAPACITY LOST —·—·—

5 cm

STATISTICAL DATA FOR POROSITY AND PERMEABILITY HISTOGRAM

COMPANY: AMOCO EXPLORATION
FIELD : YOLLA

WELL : YOLLA NO. 1
COUNTY, STATE: VICTORIA

AIR PERMEABILITY : MD. (HORIZONTAL) RANGE USED 0.000 TO 204.
POROSITY : PERCENT (HELIUM) RANGE USED 0.0 TO 46.0

(PERMEABILITY UNCORRECTED FOR SLIPPAGE)

DEPTH LIMITS : 6055.0 - 6099.8 INTERVAL LENGTH : 44.8
FEET ANALYZED IN ZONE : 8.0 LITHOLOGY EXCLUDED : NONE

DATA SUMMARY

POROSITY	PERMEABILITY AVERAGES		
AVERAGE	ARITHMETIC	HARMONIC	GEOMETRIC
28.9	63.	32.	44.

STATISTICAL DATA FOR POROSITY AND PERMEABILITY HISTOGRAM

COMPANY: AMOCO EXPLORATION
FIELD : YOLLA

WELL : YOLLA NO. 1
COUNTY, STATE: VICTORIA

GROUPING BY POROSITY RANGES

POROSITY RANGE	FEET IN RANGE	AVERAGE POROSITY	AVERAGE PERM. (GEOM.)	AVERAGE PERM. (ARITH)	FREQUENCY (PERCENT)	CUMULATIVE FREQUENCY (%)
24.0 - 26.0	2.0	25.5	14.	14.	25.0	25.0
28.0 - 30.0	2.0	29.4	53.	56.	25.0	50.0
30.0 - 32.0	4.0	30.3	73.	91.	50.0	100.0

TOTAL NUMBER OF FEET = 8.0

STATISTICAL DATA FOR POROSITY AND PERMEABILITY HISTOGRAM

COMPANY: AMOCO EXPLORATION
FIELD : YOLLA

WELL : YOLLA NO. 1
COUNTY, STATE: VICTORIA

GROUPING BY PERMEABILITY RANGES

PERMEABILITY RANGE	FEET IN RANGE	AVERAGE PERM. (GEOM.)	(ARITH)	AVERAGE POROSITY	FREQUENCY (PERCENT)	CUMULATIVE FREQUENCY (%)
10.- 20.	2.0	14.	14.	25.5	25.0	25.0
20.- 40.	1.0	37.	37.	29.2	12.5	37.5
40.- 80.	4.0	57.	58.	30.0	50.0	87.5
160.- 320.	1.0	204.	204.	30.9	12.5	100.0

TOTAL NUMBER OF FEET = 8.0

472043

STATISTICAL DATA FOR POROSITY AND PERMEABILITY HISTOGRAM

COMPANY: AMOCO EXPLORATION
FIELD : YOLLA

WELL : YOLLA NO. 1
COUNTY, STATE: VICTORIA

POROSITY-FEET OF STORAGE CAPACITY LOST FOR SELECTED POROSITY CUT OFF

POROSITY CUT OFF	FEET LOST	CAPACITY LOST (%)	FEET REMAINING	CAPACITY REMAINING (%)	ARITH MEAN	MEDIAN
0.0	0.0	0.0	8.0	100.0	28.9	30.0
2.0	0.0	0.0	8.0	100.0	28.9	30.0
4.0	0.0	0.0	8.0	100.0	28.9	30.0
6.0	0.0	0.0	8.0	100.0	28.9	30.0
8.0	0.0	0.0	8.0	100.0	28.9	30.0
10.0	0.0	0.0	8.0	100.0	28.9	30.0
12.0	0.0	0.0	8.0	100.0	28.9	30.0
14.0	0.0	0.0	8.0	100.0	28.9	30.0
16.0	0.0	0.0	8.0	100.0	28.9	30.0
18.0	0.0	0.0	8.0	100.0	28.9	30.0
20.0	0.0	0.0	8.0	100.0	28.9	30.0
22.0	0.0	0.0	8.0	100.0	28.9	30.0
24.0	0.0	0.0	8.0	100.0	28.9	30.0
26.0	2.0	22.1	6.0	77.9	30.0	30.5
28.0	2.0	22.1	6.0	77.9	30.0	30.5
30.0	4.0	47.5	4.0	52.5	30.3	31.0
32.0	8.0	100.0	0.0	0.0		

TOTAL STORAGE CAPACITY IN POROSITY-FEET = 231.1

STATISTICAL DATA FOR POROSITY AND PERMEABILITY HISTOGRAM

COMPANY: AMOCO EXPLORATION
FIELD : YOLLA

WELL : YOLLA NO. 1
COUNTY, STATE: VICTORIA

MILLIDARCY-FEET OF FLOW CAPACITY LOST FOR SELECTED PERMEABILITY CUT OFF

PERMEABILITY CUT OFF	FEET LOST	CAPACITY LOST (%)	FEET REMAINING	CAPACITY REMAINING (%)	GEOM MEAN	MEDIAN
0.005	0.0	0.0	8.0	100.0	44.26	47.57
0.010	0.0	0.0	8.0	100.0	44.26	47.57
0.020	0.0	0.0	8.0	100.0	44.26	47.57
0.039	0.0	0.0	8.0	100.0	44.26	47.57
0.078	0.0	0.0	8.0	100.0	44.26	47.57
0.156	0.0	0.0	8.0	100.0	44.26	47.57
0.312	0.0	0.0	8.0	100.0	44.26	47.57
0.625	0.0	0.0	8.0	100.0	44.26	47.57
1.250	0.0	0.0	8.0	100.0	44.26	47.57
2.500	0.0	0.0	8.0	100.0	44.26	47.57
5.	0.0	0.0	8.0	100.0	44.26	47.57
10.	0.0	0.0	8.0	100.0	44.26	47.57
20.	2.0	5.6	6.0	94.4	65.48	56.57
40.	3.0	12.9	5.0	87.1	73.40	61.69
80.	7.0	59.4	1.0	40.6	204.00	226.27
160.	7.0	59.4	1.0	40.6	204.00	226.27
320.	8.0	100.0	0.0	0.0		

TOTAL FLOW CAPACITY IN MILLIDARCY-FEET(ARITHMETIC) = 502.00

5 cm

TERIALS CODE NO 7520-551

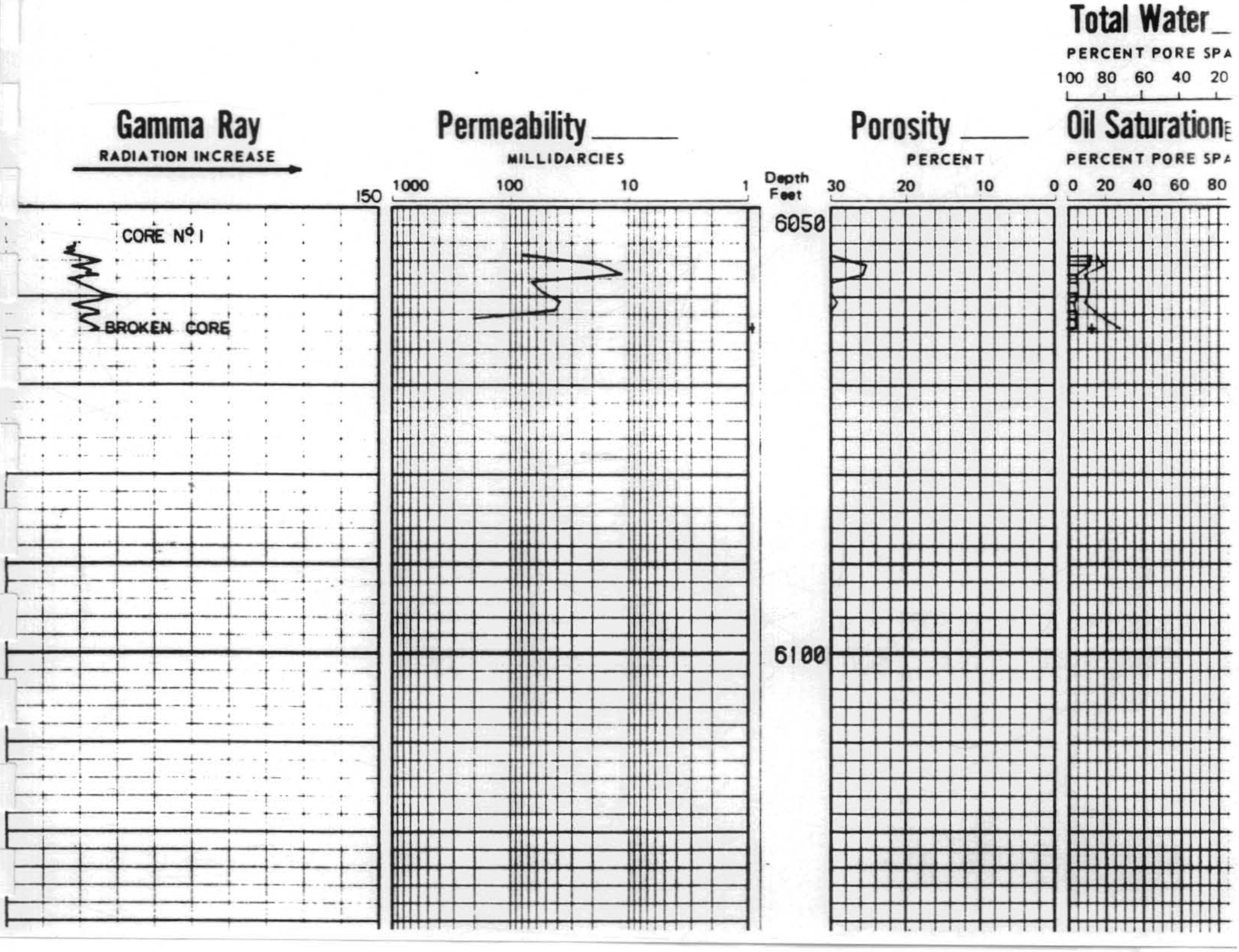
472045

CORE LABORATORIES, INC. *Petroleum Reservoir Engineering*

OMPANY AMOCO EXPLORATION
FILE NO. ADCA 85013
WELL YOLLA NO. 1
DATE 17/7/85
ELD YOLLA
FORMATION
ELEV.
OUNTY VICTORIA
STATE
DRLG. FLD.
CORES
OCATION BASS BASIN

CORRELATION COREGRAPH

VERTICAL SCALE: 1:200 FEET



472046

5 cm

LAB

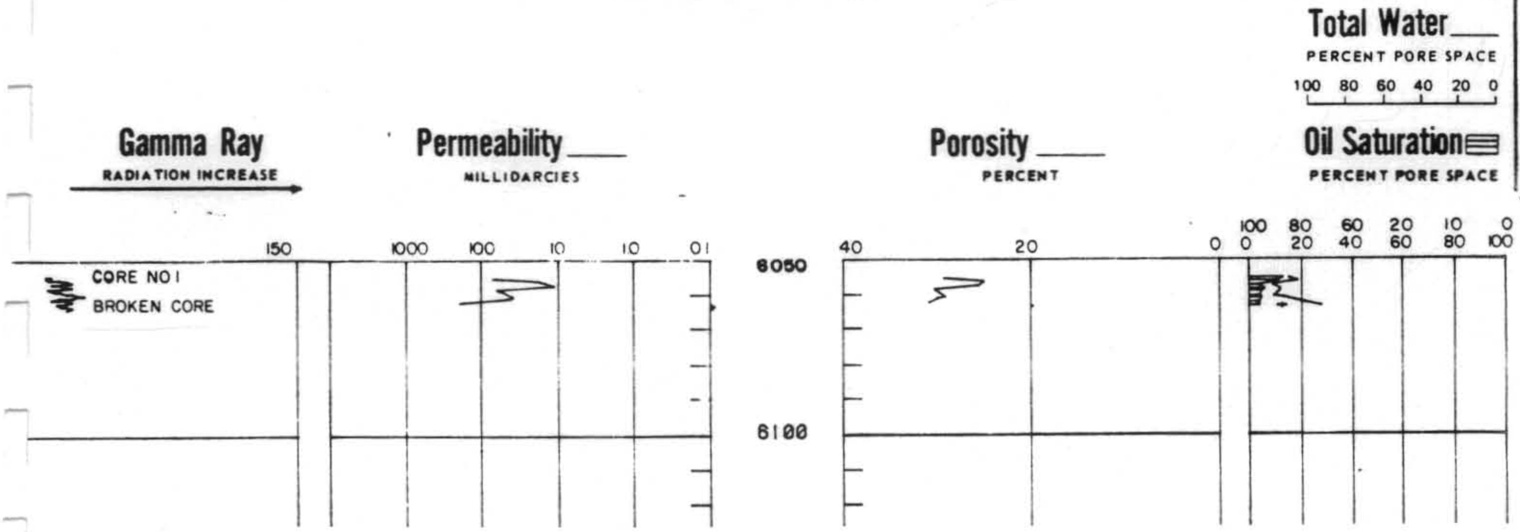
CORE LABORATORIES, INC.

Petroleum Reservoir Engineering

COMPANY AMOCO EXPLORATION
FILE NO. ADCA 85013
WELL YOLLA NO.1
DATE 17/7/85
FIELD YOLLA
FORMATION
ELEV.
COUNTY VICTORIA
STATE
DRLG. FLD.
CORES
LOCATION BASS BASIN

CORRELATION COREGRAPH

VERTICAL SCALE: 1" = 500



CORE DESCRIPTIONS

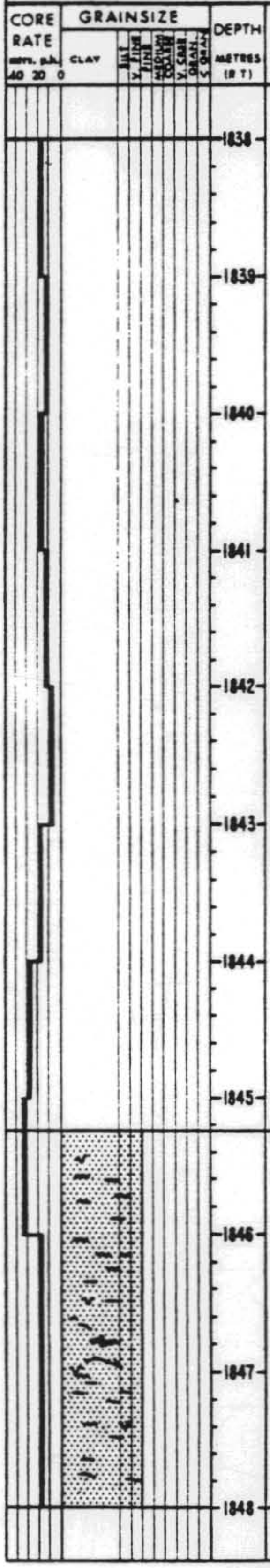
CORE #1

CORE #2

YOLLA-1

Amoco Australia Petroleum Company

WELL : **YOLLA No.1** CORE No. : 1 SHEET 1 of 1
CORED 1838 - 1848 = 10 m RECOVERED : 2·8m, 27·3% SCALE : 1: 40
FM : EASTERN VIEW COAL MEASURES DESCRIBED : GMK DATE : 25/11/85



LITHOLOGY

FINAL SLABBED CORE DESCRIPTION

TOP OF CUT CORE 1838m

Interval consists of dom vf gr Sst c̄ thin Clst laminae & clasts.
In general no lamination or bedding visible.

Sst - Lt brn gy, superfine - vf gr, sa - sr, v. w. srtd, tr brn cly mtx grdg to Clayey Sst in pt, tr mica, v. fri, exc vis por (~30%).
Clayey Sst - Dk gy brn, vf gr, sa - sr, prly srt, 15-20% brn cly mtx, v. mica, tr carb, fri, pr vis ø (~10%)
Clyst - Dk gy brn, sdy in pt, v. mica, v. sft.

ENVIRONMENT OF DEPOSITION

Probable upper shoreface to lower beach.

TOP OF RECOVERED CORE No. 1
1845·25 m (6054')

RUBBLE

1846·2m - 1847·1m SOLID CORE
Vertical burrow 2cm long at 1846·5m
Contorted Clayey Sst at 1846·6m

Small burrows throughout solid core both horizontal and vertical typically 2-4mm dia. & 1-2cms long
Probable wave oscillation ripple at 1846·8m
RUBBLE

BASE OF RECOVERED CORE No. 1
1848m (6063')

NOTE : Core recovered at base of fibreglass liner.

HYDROCARBONS

1845·25 - 1845·5

Non-uniformly distributed dull-med bri bl wh fluor in rubble.

Elsewhere core is flushed/or is water-wet.

Note : Wellsite observations were : even lt brn oil stain with even med gold yel fluor.

CORE ANALYSIS

POR.	AIR PERM. (md)		RES. FLUIDS (%)	
%	Kh	Kv	So	Sw
29·6	75		12·5	84·8
25·2	17		11·1	81·3
25·8	11		4·3	90·6
30·4	65		5·6	88·3
30·0	51		5·0	88·5
29·2	37		3·7	90·5
30·0	42		4·6	86·2
30·9	204		4·2	79·9
*28·6	**		3·5	79·8

* Summation of fluids porosity
** Broken core

5 cm

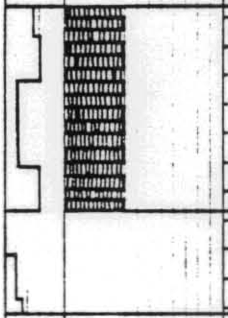
472049

Amoco Australia Petroleum Company

WELL **YOLLA No.1** CORE No. 2 SHEET 1 of 1

CORED 3344·7 - 3346·8 m = 2·1m RECOVERED 1·4m, 64 % SCALE 1:40

FM EASTERN VIEW COAL MEASURES DESCRIBED GMK DATE 21/8/85



CORE RATE METRES 4 2	GRAINSIZE CLAY SILT V. FINE FINE MEDIUM COARSE V. COARSE GRAN. V. GRAN.	DEPTH METRES (FT)	LITHOLOGY	HYDROCARBONS	CORE ANALYSIS POR %	AIR PERM (md) Kh	Kv	RES. FLUIDS (%) So	Sw
			FINAL SLABBED CORE DESCRIPTION						
		3344	TOP OF CUT CORE 3344·7m						
		3345	WHOLLY AMYGDALOIDAL BASALT	NIL		NO CORE ANALYSES PERFORMED			
		3346	BASE OF RECOVERED CORE 3346·1m						
		3347	BASE OF CUT CORE 3346·8m						

LITHOLOGY : Severely altered amygdaloidal basalt - pl ol to ol gy, common fracs & veins, occ open but usually filled, amygdales upto 2cm dia, occ flattened by flowage, occ unfilled, rock firm to hard where relatively fresher.
Compositionally · relict fgr intergranular texture consisting of altered feldspar laths with surrounding groundmass of altered mafics (probably consisting of original pyroxene (s) & olivine (?)), iron oxides & sulphides.

5 cm

Attachment No. 3b

SIDEWALL CORE DESCRIPTIONS

YOLLA WELL NO. 1

SIDEWALL CORES - YOLLA-1

A piggy-back gun of sidewall cores was shot on log suite No. 3 in Yolla-1. A total of 51 shots were attempted and 48 were recovered.

Because of the common occurrence of hydrocarbons in the sidewall cores, a rating system was devised to emphasize those sands that had the best hydrocarbon shows, and as a corollary, those sands that might be oil-prone.

The hydrocarbon rating scheme is as follows:

Rating	**Hydrocarbon Features**
NIL	nil hydrocarbon to a dessication ring only
TRACE	crush cut and dessication ring only
POOR	cut, crush cut and dessication ring
FAIR	trace fluorescence, cut, crush cut and dessication ring
GOOD	abundant fluorescence, cut, crush cut and dessication ring
EXCELLENT	live oil stain present, abundant fluorescence, cut, crush cut and dessication ring

According to this scheme, 5 sidewall cores (2974.5 m, 2952.5 m, 2874 m, 2813 m, 1835 m) were adjudged to have an excellent hydrocarbon rating and are probably light oil-bearing. The remainder of the cores were rated as poor to fair and are probably gas-saturated.

472052

SIDEWALL CORE SUMMARY - YOLLA NO.1

No.	Depth (m)	Rock Type	Grain Size	Matrix/Cement	Porosity(%)	Stain	Fluorescence	Cut	Crush Cut	Dessic. Ring	Ratings
1	3028	Cly Sst	Vf-f	Wh & brn cly	10-20	Spotty, lt brn	Dull yel-brn	Clr, v transp lt yel	Clr, mod transp lt ylw-wh	Clr, brt gold-yel	Poor
2	3014.5	Sdy Carb Clyst	(vf-f)	-	tr frac por	-	Tr v dull yel-brn	Clr dull lt yel	V lt brn w/bl-wh	Lt brn, v brt gold-yel	Poor
3	3013	Sst	Vf-f	Kaol, tr calc	20-30	V spotty lt brn	V dull yel-brn	Clr, v faint yel	Clr, transp lt yel	Clr, mod brt lt yel	Poor
4	3010	Sst	Vf-f	Kaol, tr calc	10-20	Tr spotty lt brn	Yel-brn	Clr transp dull lt yel	Clr, mod brt lt yel	Clr, mod brt lt gold-yel	Poor
5	3006	Sdy Carb Clyst	(Vf)	-	Tr frac por	Tr spotty lt brn	Spotty dull yel-brn	Clr, brt lt yel bl-wh	Clr, brt transl, lt yel bl-wh	Lt brn, v brt gold-yel	Poor
6	3002.5	Cly Sst	Vf-f	Abnt Kaol (?)	10-20	Tr lt brn	Mod even v dull yel-brn	Clr, faint yel	Clr, mod brt transp, lt yel	Clr, mod brt lt yel	Poor
7	2994	Cly Sst	Vf-f	Kaolin (?)	10-20	Tr lt brn	Tr dull yel-brn	Clr, dull yel	Clr, mod brt transp, lt yel	Clr, mod brt lt yel	Poor
8	2992	N.R.	-	-	-	-	-	-	-	-	-
9	2988	Cly Sst	Vf-f	Mod Clayey	10-20	-	Mod even med yel-brn	Clr, transp lt yel	Clr, v brt transp, med yel	Lt brn, mod dull yel	Poor
10	2985	Sst w/Clyst	Vf	Kaolinitic (?)	10-20	Tr lt brn	Tr dull yel-brn	Clr, v brt transp, lt yel	Clr, v brt transl, lt yel bl-wh	Med brn, brt yel-gold	Poor
11	2974.5	Cly Sst	Vf-f	Abun Kaol (?)	15-25	Tr spotty lt brn	Spotty dull gold yel	Clr, v brt bl-wh	Clr, v brt transp, bl-wh	Clr, mod brt lt yel bl-wh	Excellent
12	2970	Clyst	-	-	-	-	-	Clr, v pl yel	Clr, v brt transp bl-wh	Med brn, v brt yel-gold	Poor
13	2960.5	Slty Sdy Clyst	(Vf)	-	-	Tr lt brn	Tr dull yel-brn	Clr, pl yel	Clr, mod brt transp yel-bl-wh	Clr, mod brt lt yel	Poor
14	2952.5	Cly Sst	Vf-f	Bent-Kaol (?)	10-25	Patchy lt brn	Even-patchy mod brt lt-yel	V brt, transp yel bl-wh	Lt brn, brt transl lt yel-bl-wh	Lt brn, brt med yel	Excellent
15	2945	Clyst	-	-	-	-	-	Clr, lt yel	Clr, lt bl-wh	Clr, lt yel	Poor
16	2885	Clyst	-	-	Frac Por	-	-	Tr v lt yel	Clr, transp med lt yel	Clr, mod brt lt yel	Poor
17	2879.5	Sst	Vf	Abnt Kaol (?)	10-20	Tr lt brn	Tr dull yel-brn	Clr, v lt yel	Clr, mod brt transp lt yel	Clr, mod brt yel	Poor
18	2874	Sst	Vf	Abnt Kaol (?)	20-30	Tr v lt brn	Pl dull yel-brn	Clr, mod brt v lt yel	Clr, v brt transp yel-bl-wh	Clr, mod brt yel	Excellent

SIDEWALL CORE DESCRIPTIONS

Core No. 1 Well: Yolla -1

Depth: 3028m (9934.3')

Rock Type: Clayey Sandstone

Pull: 381.7 lbs

Recovered: 1.5cm (0.59")

Condition: Broken

Description:

Clayey Sandstone: Macro gry-wht, brnsh-gry to med brn mottled w/blk in one thin bed; micro dom gry-wht w/abund med to dk brn cly frags and beds and one blk to "rust" brnsh-blk resinous, fusain-type coal bed; v/fn-minor fn, mod poor sort; ang to minor sub-ang, gry-to brnsh-frsted w/abund clr qtz and feldsp w/abund decay kaolin (?) as dom non-calc matrix w/v/minor variably brn cly matrix segments; tr to v/abund blk to brnsh-blk microcarb; tr blk mafics (?); tr mica (musc); rare dk reddish-brn, anhedral garnet (?); vis por 10-20%.

Core No. 2 Well: Yolla -1

Depth: 3014.5m (9890')

Rock Type: Sandy, Carbonaceous Claystone

Pull: 1096.0 lbs

Recovered: 1.5cm (0.59")

Condition: Broken

Description:

Sandy, Carbonaceous Claystone: Macro med dk "chocolate" brn; micro even med dk brn w/gd tr to abund scattered specular reflection from micromica (musc); mod soft to gd tr v/hd; sub-fis as "shaley", tr calc (10% HCI) and mod crypto-fis; non-hydratable; gd tr to v/abund v/fn-fn, ang, brn-frsted to minor gry-frsted qtz and feldsp grains; tr appar fracture por.

Core No. 3 Well: Yolla -1

Depth: 3013m (9885.1')

Rock Type: Sandstone

Pull: 1188 lbs

Recovered: 2cm (0.79")

Condition: Broken

Description:

Sandstone: Macro med gry-tan to gry-brn mottled w/thin, dk brn "bands"; micro med gry to med tan and gry tan mottled w/blk carbonaceous microbeds; v/fn-fn and mod poor sort; dom lt to gry-frsted w/v/minor lt brnsh-frsted, ang to sub-ang (esp clr) qtz and minor feldsp in variably tan, appar decay matrix of dom tr calc. kaolin (?); tr dissem blk microcarb to banded concentrations of dissem blk microcarb bet microbeds of blk, glossy, conchoidal,vitrain-type bituminous coal; vis por 20-30%.

SIDEWALL CORE SUMMARY - YOLLA NO.1 (Cont'd)

No.	Depth (m)	Rock Type	Grain Size	Matrix/Cement	Porosity(%)	Stain	Fluorescence	Cut	Crush Cut	Dessic. Ring	Ratings
19	2845.5	Sst	Vf-f	Bent-Kaol (?)	15-25	Rare v lt brn	Rare v lt dull yel	-	Clr, v lt yel	V pl yel	Poor
20	2841.5	Sst	Vf	Bent-Kaol (?)	15-25	Rare v lt brn	Rare v lt dull yel	Rare v faint yel	Clr, v lt yel	V pl yel	Poor
21	2828.5	Sst	Vf	20-40% mod calc Bent-Kaol (?)	15-25	Mod even v lt brn	V lt dull yel	-	Clr, pl yel	V pl yel	Poor
22	2823.5	Sst	Vf-f	20-25% mod calc Bent-Kaol (?)	25-30	Mod even v lt brn	Tr v lt dull yel	Clr, v pl yel	Clr, med lt yel	Clr, med yel	Poor
23	2820	Sst	Vf-f	Kaol (?)	20-30	Rare v lt brn	Rare v dull yel-brn	Clr, v lt yel-bl-wh	Clr, v brt transp bl-wh	V lt brn, v, brt, gold-yel	Poor
24	2813	Sst	Vf-f	Kaol (?)	20-30	Spotty lt brn	25% patchy pl bl-wh	Clr, mod brt lt yel	Clr, v brt transp, lt yel	Clr, mod brt v lt yel	Excellent
25	2810	Sst	Vf	Mod Abnt Kaol (?)	20-25	Rare v lt brn	Rare yel-bl-wh	Clr, med yel	Clr, mod brt transp, lt yel	Clr, mod brt lt yel	Poor
26	2763*	Sst	Vf-f	Kaol (?)	Indeterminate	Rare v lt brn	Rare v lt dull yel-brn	Indeterminate	Indeterminate	Indeterminate	Fair
27	2759.5	Sst	Vf-f	Kaol (?)	15-25	Rare lt brn	Rare dull yel-brn	Clr, v lt yel-bl-wh	Clr, mod brt transp, lt yel-bl-wh	Clr, mod brt lt yel	Poor
28	2756	Sst	Vf	20-40% Kaol(?)	15-20	Uneven v lt brn	Uneven v lt dull yel	Clr, mod lt yel	Clr, mod brt lt yel	V lt dull yel	Poor
29	2731	Clyst	-	-	Frac por	-	-	Clr, v faint yel	Clr, mod brt transp, lt yel	Clr, med yel	Poor
30	2725.5	I/b Sst & Clyst	Vf-f	20-30% tr calc kaol (?)	15-20	Patchy v lt brn	V pl yel	Clr, mod lt yel	Clr, v brt transp, med yel	Clr, mod brt canary yel	Fair
31	2720	Sst	Vf-f	30% tr calc kaol (?)	25	Mod even v lt brn	Mod even v lt dull yel	Clr, mod brt transp, lt yel	Clr, mod brt, transp, med lt yel	Clr, dull med yel	Poor
32	2642.5	N.R.	-	-	-	-	-	-	-	-	-
33	2636	Igneous	-	-	-	-	-	-	-	-	-
34	2630	Clyst w/Sst	Vf	Kaol (?)	10	Rare lt brn	Rare dull yel-brn	Clr, mod brt pl yel-bl-wh	Clr, mod brt transp, yel-bl-wh	Clr, mod brt lt yel	Poor
35	1894	N.R.	-	-	-	-	-	-	-	-	-
36	1868	Sst	Vf-f	Kaol (?)	20-30	Spotty v lt brn	V faint dull yel	-	Clr, v faint yel	-	Poor
37	1860	Cly Sst	Vf	Kaol (?)	15-20	Gd tr spotty v lt brn	Rare dull yel-brn	-	Clr, mod brt, transp lt yel	Clr, v lt yel	Poor

*Poor Sample.

Core No. 4 Well: Yolla -1

Depth: 3010m (9875.2')

Rock Type: Sandstone

Pull: 822 lbs

Recovered: 1cm (0.39")

Condition: Broken

Description:

Sandstone: Macro gry-tan and lt to med brn mottled; micro gry-tan and med brn mottled; v/fn-fn, mod poor sort; ang to minor sub-ang, rare subhedral, grysh-to brnsh-frsted and clr to gd tr vitreous dom qtz w/minor feldsp in abund decay kaolinitic (?), tr calc matrix of dom gry-wht color when water-inundated; mod hd and fri w/mod pres; tr to gd tr blk dissem microcarb; vis por 10-20%.

Core No. 5 Well: Yolla -1

Depth: 3006m (9862.1')

Rock Type: Claystone

Pull: 553.5 lbs

Recovered: 2cm (0.79")

Condition: Broken

Description:

Sandy, Carbonaceous Claystone w/Sandstone beds: Macro dom med dk "chocolate" brn w/med gry-wht thin (1-3mm) beds; micro variably med to dk brn clystn w/gry-wht ss microbeds and lt to med gry-wht ss macrobeds; ss v/fn, mod well sort w/ang, dom frosted w/minor clr, dom ang qtz and feldsp w/abund gry-wht, non-calc, kaolinitic (?) matrix, giving mod soft, extr fri character; clystn mod hd w/gd tr to extr abund equiv sd and ss incl a gd tr to v/abund dissem to tr bedded microcarb w/ tr to abund micromica (musc); tr vis fracture por in clystn and 5-10% vis ss por.

Core No. 6 Well: Yolla -1

Depth: 3002.5m (9850.6')

Rock Type: Clayey Sandstone

Pull: 1141 lbs

Recovered: 1.9cm (0.75")

Condition: Solid

Description:

Clayey Sandstone: Macro med gry-tan; micro med gry-wht to gry-tan mottled; v/fn- fn, ang to v/minor sub-ang, grysh-to brnsh-frsted to clr qtz and feldsp in abund tan-wht to lt tan, non-calc, kaolintic (?) matrix; tr to gd tr dissem blk microcarb; vis por 10-20%.

Core No. 7 Well: Yolla -1

Depth: 2994m (9822.7')

Rock Type: Clayey Sandstone

Pull: 1347 lbs

Recovered: 2cm (0.79")

Condition: Solid

Description:

Clayey Sandstone: Macro lt brn and gry-tan mottled; micro gry-wht, gry-tan to lt brn mottled; v/fn-fn, mod poor sort; ang to sub-ang, grysh-to brnsh-frsted and clr dom qtz w/minor feldsp in matrix of non-calc, tan-wht to gry-wht kaolin (?); gd tr dissem blk microcarb; rare dk reddish-brn, anhedral garnet (?); vis por 10-20%.

Core No. 8 Well: Yolla -1

Depth: 2992m (9816.2')

Rock Type:

Pull: 1574 lbs

Recovered: No Recovery

Condition:

Description:

Core No. 9 Well: Yolla -1

Depth: 2988m (9803')

Rock Type: Clayey Sandstone

Pull: 1623 lbs

Recovered: 3.5cm (0.72")

Condition: 2.3cm (0.91") solid

Description:

Clayey Sandstone: Macro med grysh-brn; micro med gry w/abund mot med gry-brn and med dk brn opposing streaks; v/fn to minor fn w/mod gd sort, ang to minor sub-ang to abund subhedral dom grysh-frsted to abund clr (subhedral) qtz w/v/minor feldsp; tr mica (musc); tr blk mafics (?); dom med clyey w/abund sdy clystn fragments and lattice-type forms w/cly med to highly hydratab;e (bentonitic ?); mod soft and v/easily fri w/sdy clystn portions highly plastic; non-calc (10% HCI); vis por = 10-20%.

Core No.10 **Well: Yolla -1**

Depth: 2985m (9793.2')

Rock Type: Sandstone w/Claystone

Pull: 732.5 lbs

Recovered: 2.2cm (0.87")

Condition: Broken

Description:

Sandstone w/Claystone: Macro med gry-tan (ss) w/dk brn frags and "layers" (clystn); micro lt gry to gry-wht ss and dk reddish-brn clystn; ss v/fn, mod poor sort; ang to sub-ang, frsted to clr qtz and minor feldsp in a crmy-wht to gry-wht, non-calc, kaolinitic (?) matrix; clystn non-calc, tr sdy and highly blk to reddish-blk microcarbonaceous w/gd tr micromica (musc); ss vis por 10-20%.

Core No.11 **Well: Yolla -1**

Depth: 2974.5m (9758.7')

Rock Type: Clayey Sandstone

Pull: 1492 lbs

Recovered: 2.3cm (0.91")

Condition: One 2.0cm (0.79") increment with grains

Description:

Clayey Sandstone: Macro lt brnsh-tan to med brn mottled; micro med gry-wht to med brn w/abund blk mottled; v/fn to fn, mod poor sort; dom ang w/minor sub-ang to sub-rnd, grysh-to brnsh-frsted to minor clr and abund vitreous qtz and feldsp; abund non-calc kaolinitic (?) matrix cly as appar decay product; mod hd easily fri to mod plastic disintegration from cly content; v/abund to abund ang, blk dissem microcarb; tr blk to brnsh-blk mafics (?); tr mica (musc); rare dk reddish-brn, anhedral garnet (?); vis por 15-25%.

Core No.12 **Well: Yolla -1**

Depth: 2970m (9744')

Rock Type: Claystone

Pull: 582 lbs

Recovered: 1.5cm (0.59")

Condition: Broken

Description:

Claystone: Macro dk brn; micro med dk brn w/abund specular reflections from mica: mod hd and subfis as "shaley"; non-calc; tr to gd tr v/fn-cse silty to v/fn sdy (ang, clr to frsted qtz); tr to gd tr brnsh-blk microcarb layers.

Core No.13 Well: Yolla -1

Depth: 2960.5m (9712.8')

Rock Type: Silty, Sandy Claystone

Pull: 547 lbs

Recovered: 2.2cm (0.87")

Condition: Solid w/frags

Description:

Silty, Sdy Claystone: Macro med lt gry-brn; micro med gry-brn to minor med brn mottled; med hd and subfis as "shaley"; non-calc; variably abund v/fn-cse silt-grade and v/fn, ang, frsted to clr, qtz and feldsp in gd tr (only) grain contact; gd tr dissem micromica (musc) and microcarb; mod hydratable (hygroturgid).

Core No.14 Well: Yolla -1

Depth: 2952.5m (9686.5')

Rock Type: Clayey Sandstone

Pull: 1602 lbs

Recovered: 2.5cm (0.98")

Condition: Broken to granulated w/one 1.7cm (0.67') segment

Description:

Clayey Sandstone: Macro lt brnsh-gry to lt to med dk brn mottled; micro lt to dk gry-wht and lt to dk brn mottled; very fn to fn and poorly sorted dom ang to abund subhedral and gd tr sharp dom frsted w/abund clr and rare vitreous dom qtz (inc. subhedral) and minor feldsp in a brnsh-tan, glassy-lustered, non-calc bentonitic (?) to lt gry-wht, resinous-lustered, non-calc kaolinitic (?) matrix; mod hd and fri w/mod pres; tr mica (must); tr blk to brnsh-blk mafics (?); vis por 10-25%.

Core No.15 Well: Yolla -1

Depth: 2945m (9662')

Rock Type: Claystone

Pull: 668 lbs

Recovered: 1.2cm (0.47")

Condition: Broken

Description:

Claystone: Macro med dk "chocolate" brn; micro med dk reddish-brn; mod hd and highly sub-fis as v/"shaley"; tr calc and v/poorly hydratable; abund micromica; rare silt to v/fn qtz grains; rare dissem blk microcarb.

Core No.16 Well: Yolla -1

Depth: 2885m (9465.1')

Rock Type: Claystone

Pull: 685 lbs

Recovered: 1.4cm (0.55")

Condition: Broken

Description:

Claystone: Macro dk "chocolate" brn; micro med dk "chocolate" brn; mod hd and dense, sub-fis w/blky frac and abund curved parting; mod homogeneous w/tr to abund dissem to aggregate micropyrite, rare to gd tr v/fn to cse silt and v/fn sd and gd tr micromica (musc); v/slight tr calc (dolomitic ?); v/slight try hydratable; vis frac por 5%.

Core No.17 Well: Yolla -1

Depth: 2879.5m (9447.1')

Rock Type: Sandstone

Pull: 816.5

Recovered: 1.4cm (0.55")

Condition: Solid

Description:

Sandstone: Macro alternating thin (1-10mm) beds of med gry (1-3mm) to med brn as "salt and pepper"; micro dom med gry and brn mottled w/lt to med gry w/dissem blk from microcarb and rare mafics (?); v/fn and mod well sort ang to v/minor sub-ang frsted w/v/minor clr qtz and minor feldsp in abund gry-wht to lt gry, non-calc kaolinitic (?) matrix; vis por 10-20%.

Core No.18 Well: Yolla -1

Depth: 2874m (9429.0')

Rock Type: Sandstone

Pull: 521.5

Recovered: 2.0cm (0.79")

Condition: Broken

Description:

Sandstone: Macro "salt and pepper" lt tan and med brn; micro mottled lt to med gry to gry-brn w/v/abund dissem blk microcarb; v/fn and mod well sorted, ang to minor sub-ang frsted to clr w/rare vitreous dom qtz w/minor feldsp in dom sparse to rare abund lt gry to gry-wht, non-calc kaolinitic (?) matrix; rare micromica (musc); vis por 20-30%.

Core No.19 Well: Yolla -1

Depth: 2845.5m.(9335.5')

Rock Type: Sandstone

Pull: 1620 lbs

Recovered: 3.0cm (1.18")

Condition: Solid to broken

Description:

Sandstone: Macro v/fn "salt and pepper" lt to med gry, variable tan and blk; micro gry-wht to lt gry, variably tan and brnsh-blk to blk as, respectively, highly kaolinitic (?) ss beds (0.4-1.2mm), tr to gd tr w/rare v/clyey ss beds (0.4-1mm) w/tr brnsh-blk microcarbonaceous, thin (0.2-0.4mm), and abund (15%) dissem blk to brnsh-blk mafics (?), the "cleaner" ss matrix as v/lt gry-wht, tr calc, highly hydratable (hygroturgid) bentonitic (?) and kaolinitic (?); vis por 15-25% w/v/fn to fn, mod poor sort, ang to variably minor sub-ang to sharp, frsted to clr w/gd tr vitreous qtz and feldsp; tr micromica (musc).

Core No.20 Well: Yolla -1

Depth: 2841.5m.(9322.4')

Rock Type: Sandstone

Pull: 876 lbs

Recovered: 2.2cm (0.87")

Condition: Broken to Shattered

Description:

Sandstone: Macro thin (1mm) bedded med gry and lt brn; micro med gry ss and gry-tan to lt gry-brn ss as microbedded (0.3-1.2mm) w/rare blk, microcarbonaceous beds (0.3mm); v/fn and mod well sort, ang, frsted to minor clr dom qtz and minor feldsp w/gd tr dissem blk microcarb and micromica and tr lt to med brn linear to lense-shaped, blended clyey ss inclusions; mod hd to mod soft and easily fri to fri w/mod pres; matrix lt to med gry, non-calc, highly hydratable (as hygroturgid), bentonitic (?) and kaolinitic (?); vis por 15-25%.

Core No.21 Well: Yolla -1

Depth: 2828.5m (9279.7')

Rock Type: Sandstone

Pull: 768 lbs

Recovered: 3.0cm (1.18")

Condition: Broken to shattered w/one solid segment (1.7cm or 0.67")

Description:

Sandstone: Macro variably grysh-tan w/thin (0.2-1mm) med brn bands (beds); micro dom gry-wht w/minor gry-tan mottled w/variably lt brn from clystn beds (0.2-1mm thick as 10% of specimen); v/fn, mod well sort ang, frsted to clr dom qtz w/minor feldsp in a gry-wht to gry-tan w/abund lt to med tan (residual oil stained ?), mod calcitic and mod hydratable (w/hygroclastic disintegration of ss frags), bentonitic (?) and kaolinitic (?) matrix (20-40%); vis por 15-25%, mod soft and fri w/extr ease; clystn as the thin, non-calc, gd tr to abund blk to brnsh-blk microcarbonaceous, variably v/fn to cse silty and v/fn sdy interbeds; slight tr to tr dissem micromica (musc) in ss and clystn.

Core No.22 Well: Yolla -1

Depth: 2823.5m (9263.3')

Rock Type: Sandstone

Pull: 1323 lbs

Recovered: 2.4cm (0.94")

Sandstone: Macro mottled med lt gry-tan to lt tan; micro gry-wht to tan-wht mottled; v/fn-fn and mod poor sort, ang to sharp and rare sub-ang gry-frsted to clr w/v/minor brn-frsted to med brn dom qtz w/minor feldsp and gd tr blk mafics (?) and blk microcarb in a gry-wht, tan-wht to gry-tan, mod calcitic, bentonitic (?) and kaolinitic (?) matrix (20-25%); vis por 25-30%; v/soft and fri w/extr ease. (Note: cly matrix mod hydratable as hygroclastic.)

Core No.23 Well: Yolla -1

Depth: 2820m (9251.8')

Rock Type: Sandstone

Pull: 1043 lbs

Recovered: 2.0cm (0.79")

Condition:

Description:

Sandstone: Macro dom med brn w/lt to med tan mottling; micro dom med gry-wht w/abund gry-tan to lt brn mottling; v/fn to rare fn w/mod poor sort of ang to minor sub-ang, gry-to brn-frsted and clr w/rare vitreous dom qtz w/minor feldsp in med gry to gry-tan, non-calc, kaolinitic (?) matrix; tr dissem blk microcarb w/rare blk, vitrain-type serrated "seams"; rare to tr micromica (musc); vis por 20-30%.

Core No.24 Well: Yolla -1

Depth: 2813m (9228.9')

Rock Type: Sandstone

Pull: 787.5 lbs

Recovered: 2.3cm (0.91")

Condition: Broken

Description:

Sandstone: Macro tan and tan-wht mottled; micro tannish-wht, tannish-brn to lt brn mottled; v/fn-fn, very poor sort; dom frsted to clr w/v/minor brnsh-frsted to rare vitreous qtz and minor feldsp in a crmy-wht to tan-wht, non-calc kaolinitic (?) matrix, varying from gd tr to v/abund; gd tr dissem blk microcarb; rare micromica (musc) and dk red-brn, anhedral garnet (?); vis por 20-30%.

Core No.25 Well: Yolla -1

Depth: 2810m (9219')

Rock Type: Sandstone

Pull: 652 lbs

Recovered: 1.4cm (0.55")

Condition: Broken

Description:

Sandstone: Mega med gry-tan; micro lt gry w/v/minor lt brn mottling; v/fn and mod well sort; ang, frsted to clr dom qtz w/minor feldsp in mod abund gry-wht, non-calc,kaolinitic (?) matrix; mod soft and v/easily fri; gd tr to med abund dissem micromica (müsc) and blk microcarb; vis por 20-25%.

Core No.26 Well: Yolla -1

Depth: 2763m (9064.8')

Rock Type: Sandstone

Pull: 274 lbs

Recovered: 0.4cm (0.16")

Condition: Extremely poor sample w/frags and mud

Description:

Sandstone: Micro gry-tan; v/fn-fn w/poor sort ang, frsted to clr dom qtz w/minor feldsp in med gry, non-calc kaolinitic (?) matrix; gd tr dissem and seamed blk microcarb; vis por indeterminate.

Core No.27 Well: Yolla -1

Depth: 2759.5m (9053.4')

Rock Type: Sandstone

Pull: 624.5 lbs

Recovered: 2.0cm (0.79")

Condition: Broken

Description:

Sandstone: Macro med gry-tan to lt brn mottled; micro variably med gry-wht to brnsh-tan mottled to "banded"; v/fn-v/minor fn w/mod gd sort of ang, frsted w/v/minor clr dom qtz and minor feldsp in lt to med gry to gry-tan, non-calc, kaolinitic (?) matrix; tr to gd tr dissem w/tr microbedded blk microcarb; rare micromica (musc); vis por 15-25%.

Core No.28 Well: Yolla -1

Depth: 2756m (9041.9')

Rock Type: Sandstone

Pull: 492.5 lbs

Recovered: 2.5cm (0.98")

Condition: Shattered

Description:

Sandstone: Macro med lt gry to gry-tan w/med brn to med dk brn interbeds; micro dom lt gry w/med dk brn clystn interbeds (0.6-2mm thick as 20% of specimen); v/fn and mod well sort, ang, frsted to clr qtz w/minor feldsp in a v/lt gry-wht to lt gry-tan and abund tan (residual oil stained ?), non-calc, kaolinitic (?) matrix (20-40%); vis por 15-20%; tr to gd tr dissem blk microcarb; extr hd to mod soft and fri w/high pres to fri w/low pres; clystn mod hd, sub-fis, non-calc, tr to abund blk to reddish-blk microcarb; ss and clystn w/tr to gd tr micromica (musc).

Core No.29 Well: Yolla -1

Depth: 2731m (8959.9')

Rock Type: Claystone

Pull: 464 lbs

Recovered: 2.5cm (0.98")

Condition: Broken

Description:

Claystone: Macro dk "chocolate" brn; micro uniformly dk reddish brn; mod hd, highly sub-fis w/abund contorted parting and abund frac partings of med brnsh-tan color; non-calc; v/abund dissem micromica (musc); tr vfn to cse silty and slight tr v/fn sdy; approx 5% vis frac por.

Core No.30 Well: Yolla -1

Depth: 2725.5m (8941.8')

Rock Type: Interbedded Sandstone and Claystone

Pull: 454 lbs

Recovered: 3.0cm (1.18")

Condition: Broken to Shattered

Description:

Interbedded Sandstone and Claystone: Macro gry-tan and dk brn bedded; micro gry-wht to lt tan ss beds (1-4mm thick) and dk brn to brnsh-blk clystn beds (0.5-5mm thick) w/both ss and clystn beds individually varying in thickness w/gd tr pinch-out forming open ended lense-types as appar crossbeds; ss v/fn to v/minor fn, ang to rare sub-ang to sharp, frsted to minor clr dom qtz w/minor feldsp in a lt to med gry-wht to gry-tan, slight tr calc, kaolinitic (?) matrix (20-30%); ss extr hd to mod soft and easily fri to v/minor fri w/mod pres (vis por 15-20%); ss w/gd tr dissem blk microcarb and rare micromica (musc); clystn mod hd, sub-fis, slight tr fis, v/abund to v/highly blk micromicaceous w/gd tr containing abund vintain-type coal "sheets", tr to v/abund v/fn-cse silty and v/fn sdy, rare micro-pyrite and micromica, tr hydratable.

Core No.31 Well: Yolla -1

Depth: 2720m (8923.8')

Rock Type: Sandstone

Pull: 582 lbs

Recovered: 2.2cm (0.87")

Condition: Shattered

Description:

Sandstone: Macro med tan and lt brn mottled; micro gry-wht, lt-med tan and lt to med brn mottled; v/fn to minor fn w/mod poor sort; ang w/abund sharp and gd tr sub-rnd, gry-wht frsted, brnsh-frsted and minor clr dom qtz w/minor feldsp in a gry-wht to med tan, tr calc, tr hydratable, kaolinitic (?) matrix (30%); vis por 25%; mod soft and v/easily fri; gd tr, variably med to med dk brn, blk microcarbonaceous, silty and v/fn sdy, non-calc, poorly hydratable clystn frags (5%); gen tr micromica (musc).

Core No.32 Well: Yolla -1

Depth: 2642.5m (8669.5')

Rock Type:

Pull: 1330 lbs

Recovered: No recovery, mud only

Condition:

Description:

Core No.33 Well: Yolla -1

Depth: 2636m (8648.2')

Rock Type: Mesocratic Igneous Rock (Andesitic ?)

Pull: 1118 lbs

Recovered: 3.2cm (1.26")

Condition: Solid w/tr rubble

Description:

Mesocratic Igneous Rock (Andesitic ?): Macro med dk grn w/abund tan-wht mottling; micro dom med grn w/mottling of blk, reddishbrn, gry-wht and clr as a porphyritic extrusive (?) w/cryptoxln to aphanitic groundmas; phenocrysts of sanidine (?) (vit), plagioclase (glassy to wht w/saussuritization (grnsh), biotite (hematitic ? as "rust" reddish-brn, hornblende (blk to reddish-brn, hematitic ?, augite (blk to grnsh-blk), brnsh hypersthene (?) and calcite (tan-wht,reactive) as dom subhedral w/approx equal anhedral w/decay; groundmas glassy w/tr to high devitrification as lithophysal, holohyaline to vitrophyric; rare vis por from appar calcite leaching.

Core No.34 Well: Yolla -1

Depth: 2630m (8628.5')

Rock Type: Claystone

Pull: 670.5 lbs

Recovered: 2.0cm (0.79")

Condition: 1.5cm (0.59") solid w/rubble

Description:

Claystone: Macro dk "chocolate" brn w/grysh-tan, thin (1-2 mm) "interbeds"; micro dk brn w/med gry-tan to med brn, v/fn ss lenses and interbeds; clystn mod hd and sub-fis; ss w/ang, frsted qtz and feldsp in lt gry-wht to gry-tan, non-calc, kaolinitic (?) matrix; all non-calc; vis ss por 10%

Core No.35 Well: Yolla -1

Depth: 1894m (6213.8')

Rock Type:

Pull: 372.5 lbs

Recovered: No recovery

Condition:

Description:

Core No.36 Well: Yolla -1

Depth: 1868M (6128.5')

Rock Type: Sandstone

Pull: 437.7 lbs

Recovered: 3.8cm (1.5")

Condition: Solid

Description:

Sandstone: Macro lt to med tan mottled w/one thin (1mm) v/dk brn "bed"; micro lt to med tan; mottled; v/fn to rare fn, mod poor sort, ang to sub-ang w/rare sub-rnd, gry-to minor brnsh-frsted and clr dom qtz w/minor feldsp in a med tan, non-calc kaolinitic (?) matrix; vis por 20-30%; dk brn clystn "bed" (1mm) highly blk microcarbonaceous, silty and poorly hydratable.

Core No.37 Well: Yolla -1

Depth: 1860m (6102.3')

Rock Type: Clayey Sandstone

Pull: 452.2 lbs

Recovered: 2.3cm (0.91")

Condition: Broken

Description:

Clayey Sandstone: Macro mottled med dk brn and med gry; micro lt to med gry ss mottled w/lt brn to med dk brn variably sdy clystn, all exchangeably as lenses, broken bed and frags w/rare slump features; ss v/fn and mod poor sort, dom frsted w/minor clr dom qtz w/minor feldsp in a lt gry to gry-tan, non-calc, kaolinitic matrix and vis por of 15-20%; clystn silty and v/fn sdy, non-calc, tr hydratable; ss/clystn =

Core No.38 Well: Yolla -1

Depth: 1855m (6085.9')

Rock Type: Clayey, calcareous sandstone

Pull: 267.5 lbs

Recovered: 1.4cm (0.55")

Condition: Broken

Description:

Clayey, Calcareous Sandstone: Macro variably lt tan to med brn mottled; micro med gry-tan to lt brn mottled ss w/abund med brn cly inclusions and gd tr to abund sub-parallel blk microcarb frags; v/fn and mod well sort, ang to abund sharp, frsted to minor clr qtz w/minor feldsp in an abund (20-40%), variably med gry-tan to med tan, mod calcitic, kaolinitic (?) matrix; vis por 15-20%; incl cly "frags" variably silty and v/fn sdy, tr blk microcarbonaceous and poorly sol; gen dissem micromica (musc) in ss and clystn.

Core No.39 Well: Yolla -1

Depth: 1850m (6069.5')

Rock Type: Sandstone

Pull: 174.8 lbs

Recovered: 3.0cm (1.18")

Condition: Broken

Description:

Sandstone: Macro v/even med brn; micro mottled lt to med brnsh-tan; v/fn, ang, frsted w/minor clr dom qtz and minor feldsp in a med tan, non-calc, kaolinitic (?) matrix (20%); even vis por 25%; tr to gd tr blk dissem microcarb w/tr as incl in clyey "frags"; tr micromica (musc); v/soft and totally fri w/extr ease.

Core No.40 Well: Yolla -1

Depth: 1845m (6053.1')

Rock Type: Sandstone

Pull: 163.6 lbs

Recovered: 2.6cm (1.02")

Condition: Broken

Description:

Sandstone: Macro variably med tan to med brn w/med dk brn beds (5%); micro mottled med gry, gry-tan, lt to med brn as variably clyey ss w/thin (3mm), dk brn, silty and v/fn sdy clystn interbeds (5%); all non-calc; ss v/fn w/mod gd sort, ang, frsted to clr qtz and feldsp in gry-tan to brnsh-tan, kaolinitic (?) matrix (20-30%) w/vis por 15-25%; ss w/rare to tr dissem blk microcarb and rare micromica (musc); ss mod to v/soft and fri w/low pres; clystn mod hd, mod sub-fis, tr micromicaceous (musc) and poorly hydratable; clystn frac por less than 5%.

Core No.41 Well: Yolla -1

Depth: 1840m (6036.7')

Rock Type: Sandstone

Pull: 253.3 lbs

Recovered: 3.1cm (1.22")

Condition: Broken

Description:

Sandstone: Macro mottled lt to med brnsh-tan; micro med tan w/mod abund med dk brn to brnsh-blk, highly microcarbonaceous, non-calc, discontinuous, rare foliated, thin (0.1-0.6mm) cly "layers" and frags, rarely as discontinuous bedding; v/fn, mod well sorted, ang to abund subhedral and gd tr sub-ang dom frsted to minor clr qtz and feldsp in a 20-30% med tan, resinous, non-calc, kaolinitic matrix; vis por 20-30%; tr micromica; rare dissem micropyrite.

Core No.42 Well: Yolla -1

Depth: 1835m (6020.3')

Rock Type: Sandstone

Pull: 317.2 lbs

Recovered: 2.9cm (1.14")

Condition: Broken w/one segment of 2.4cm (0.94")

Description:

Sandstone: Macro variably med lt tan to med brnsh-tan w/abund dk brn fn, curved appar bedding; micro lt to med gry-tan "clean" ss w/abund curved to curved and convergent, med to dk brn v/clyey ss to silty and v/fn sdy clystn as thin (0.1-0.3mm) beds, beds forming up to 10% lense-type ss increments; v/fn, mod well sort, ang, frsted to minor clr qtz w/minor feldsp in a 20% to 30%, variably gry-tan, non-calc, mod hydratable, bentonitic (?) and kaolinitic (?) matrix; tr dissem blk to brnsh-blk microcarb, blk mafics (?) and micromica (musc); v/soft and fri w/extreme ease; vis por 20-30%.

Core No.43 Well: Yolla -1

Depth: 1830m (6003.8')

Rock Type: Sandstone w/Claystone beds

Pull: 218.5 lbs

Recovered: 3.0cm (1.18")

Condition:

Description:

Sandstone: Macro tan (ss) w/abund med brn beds (clystn): micro ss lt to med grysh-tan, lt to med tan to lt to med gry and clystn med brn: ss vfn, mod well sort w/ang, frsted qtz and minor feldsp in gry-tan, non-calc, kaolinitic (?) matrix w/tr blk microcarb; clystn dom mod silty and v/fn sdy w/gd tr dissem blk microcarb, non-calc and poorly hydratable; vis frac por 5%, vis ss intergranular por to 25% in less clyey portions.

Core No.44 Well: Yolla -1

Depth: 1825m (5987.5')

Rock Type: Clayey Sandstone

Pull: 1046 lbs

Recovered: 2.8cm (1.1")

Condition: Broken

Description:

Clayey Sandstone: Macro mottled med to dk brn and lt to med tan; micro a mosaic of variably gry-tan and med to dk brn as a highly turbid mixture of 30-50% sd and 70-50% claystn w/minimal thin (0.3-1mm) bedding and abund pseudobedding and turbidity features; ss v/fn, mod well sort, ang, frsted to minor clr and gd tr brnsh-frsted qtz and minor feldsp in a gry-tan to tan, non-calc, kaolinitic (?) and tr bentonitic (?) matrix; ss vis por 10-20%; ss mod soft and easily fri; clystn non-calc, mod hydratable (hygroturgid), variably silty and v/fn sdy w/tr micromica (musc).

Core No.45 Well: Yolla -1

Depth: 1820m (5971.1')

Rock Type: Sandy, Pyritic Claystone

Pull: 288.5 lbs

Recovered: 3.5cm (1.38")

Condition: Broken

Description:

Sandy, Pyritic Claystone: Macro med dk brn and tan w/lineated mottling; micro variably med dk brn w/extr abund beds and "lenses" of med gry to med lt gry-brn, mod clyey, v/fn, mod well sorted ss w/ang, frsted to clr qtz and feldsp in a tan-wht, kaolinitic (?) matrix; the beds variably "broken", parted and w/slump features; all non-calc; tr to v/gd tr dissem and fragment-form micropyrite, rare forms w/lattice-type structures; all mod hd w/clystn highly sub-fis, "shaley" and ss as fri w/med pres; clystn w/variably abund incl silt to v/fn qtz and feldsp grains; clystn w/5% vis frac por and ss w/vis intergranular por absent.

Core No.46 Well: Yolla -1

Depth: 1815m (5954.6')

Rock Type: Clyey Sandstone

Pull: 1293 lbs

Recovered: 3.0 (1.18")

Condition: Broken

Description:

Clayey Sandstone: Macro lineated mottling of variably med to dk tan and med dk brn; micro 60-70% variably tan ss and 40-30% med dk brn clystn as appar turbidity deposits w/abund lenses, crossbeds, frags and w/abund micro-slump; ss v/fn, mod poor sort, ang to sub-ang to sub-rnd and rare sharp, gry-to brn-frsted, variably brn and clr qtz w/minor feldsp in a variably tan, non-calc, tr hydratable, kaolinitic (?) to tr bentonitic (?) matrix (20-40%); ss vis por 10-20%; ss mod hd and fri w/mod pres; clystn mod hd, sub-fis as fn beds, lenses and linear "frags" (0.2-3mm), non-calc, mod hydratable (hygrofissile), gd tr blk to brnsh-blk microcarbonaceous and tr micromicaceous (musc), variably silty and v/fn sdy.

Core No.47 Well: Yolla -1

Depth: 1810m (5938.2')

Rock Type: Sandy, Pyritic Claystone

Pull: 432.2 lbs

Recovered: 3.5cm (1.34")

Condition: Broken w/one 2.5cm (0.98") segment

Description:

Sandy, Pyritic Claystone: Macro v/dk brn w/med tan, lineated mottling; micro med dk brn clystn w/v/abund lense-type and fragment to pseudo-bed, v/fn, mod well sort, frsted to clr qtz and feldsp; ss w/tan wht kaolinitic matrix; all non-calc; gd tr to abund dissem to fragmental micropyrite; clystn v/hd and highly sub-fis w/ss mod hd and fri w/mod pres; vis por absent.

Core No.48 Well: Yolla -1

Depth: 1805m (5921.8')

Rock Type: Sandy, Pyritic Claystone

Pull: 275.7 lbs

Recovered: 3.3cm (1.3")

Condition: Broken

Description:

Sandy, Pyritic Claystone: Macro v/dk brn w/med to dk tan, lineated mottling; micro v/dk brn v/fn-cse silty and v/fn sdy clystn w/abund "lineated debris" ss as frags, lenses and rare pseudo-beds w/rare slump-like features; ss mod poor sort frsted to clr, ang qtz and feldsp in a lt tan, kaolinitic (?) matrix; tr to locally abund aggregate w/rare dissem micropyrite; all non-calc; clystn v/hd and mod sub-fis; ss mod hd and fri w/mod pres; vis por 5% in ss.

Core No.49 Well: Yolla -1

Depth: 1795m (5889')

Rock Type: Claystone

Pull: 324 lbs

Recovered: 3.6cm (1.42")

Condition: Three solid pieces

Description:

Claystone: Macro uniformly v/dk brn; micro v/dk brn w/gd tr "brass" color from incl micropyrite aggregates; mod hd and dense w/irreg frac, tr splintery; dom sub-fis, "shaley"; non-calc and gd tr hydratable (hygrofissile); rare to gd tr silt and v/fn sd (dissem); rare to tr micromica (musc ?); micropyrite as irreg, lineated to lense-type inclusions.

Core No.50 Well: Yolla -1

Depth: 1785m (5856.2')

Rock Type: Claystone

Pull: 193.8 lbs

Recovered: 4.2cm (1.65")

Condition: Solid segment of 3cm (1.18") remainder broken

Description:

Claystone: Macro dk brn; micro med dk reddish-brn w/abund multiform "brassy" micro-pyrite inclusions (ellipsoidal,"V-shaped", lineated, globular); mod hd and mod dense w/dom conchoidal frac; sub-fis; non-calc and mod hydratable (hygroclastic); tr micromica (musc ?); rare to tr silty and v/fn sdy.

Core No.51 Well: Yolla -1

Depth: 1765m (5790.6')

Rock Type: Claystone

Pull: 150.8 lbs

Recovered: 4.4cm (1.73")

Condition: Broken w/one segment of 2.5cm (0.98")

Description:

Claystone: Macro med dk "chocolate" brn; micro med dk brn w/v/abund aggregates of micropyrite and gd tr dissem micropyrite of "brass" color and gd tr to abund wht to gry-wht cly and clyey, v/fn ss frags and "micro-lenses"; v/hd and dense as sub-fis w/conchoid fracture; tr dissem micromica (musc); vis por absent; non-calc and tr hydratable (hygrofissile).

Attachment Nos. 4 through 12 provided in draft copy of Application Text.

Attachment No. 13

YOLLA RESERVES CALCULATION

Lower Zone

Gas:

$$OGIP = \frac{43560AH\text{Ø}(1\text{-}Swi)}{Bg}$$

Where:

A = Area, acres
H = Net thickness, feet
Ø = Porosity, decimal
Swi = Initial water saturation, decimal*
Bg = Gas volume factor, SCF/ft^3

$$OGIP = \frac{43560(7615)(23)(3.28)(0.17)[1-(0.30+0.19)]}{(1/212)} = \mathbf{460.09\ BCFG}$$

Gas Reserves = (OGIP)(RF) = (460.09)(.85) = **391 BCFG**

Where RF = Recovery factor

Condensate:

Condensate Reserves = CY(Gas Reserves) = (41.2)(391) = **16.1 MMBC**

Where CY = Condensate yield measured during the DST.

Upper Zone

Gas:

$$\text{OGIP} = \frac{43560(1703)(10)(3.28)(0.25)(1-(0.49+.075))}{(1/212)} = \mathbf{56.11\ BCFG}$$

Recoverable Gas = (56.11)(0.40) = **22.4 BCFG**

Condensate:
Liquids Reserves = (296)(22.4) = **6.6 MMBL**

* The water saturation used for the calculations was increased by 19% and 7.5% for the lower and upper zones, respectively to account for the measured CO_2 saturation.

Attachment No. 14

YOLLA Z-FACTOR DETERMINATION

Component	Mol Fract	Pc	Tc	%Pc	%Tc
N_2	0.0020	492.0	227.09	1.0	0.4
C1	0.6387	669.7	343.13	227.7	219.1
CO_2	0.1886	1071.0	547.49	202.0	103.3
C_2	0.0764	708.3	549.77	54.1	42.0
C_3	0.0375	616.3	665.68	23.1	24.9
IC_4	0.0065	529.1	734.63	3.4	4.8
NC_4	0.0104	550.7	765.29	5.5	7.7
IC_5	0.0038	494.7	828.69	1.9	3.2
NC_5	0.0039	487.3	845.08	1.9	3.3
C_6	0.0054	436.6	913.14	2.4	4.9
C_7+	0.0268	370.0	1110.00	9.9	29.8
Total				733	444

Reservoir Pressure = 4200

Pseudoreduced Pressure, Pr = $\frac{4200}{733}$ = 5.73

Reservoir Temperature = 752 deg R

Pseudoreduced Temperature, Tr = $\frac{752}{444}$ = 1.69

From Standing and Katz chart, z = 0.90

From Core Lab Fluid analysis, z = 0.907

DEPLETION STUDY @ 292°F

Hydrocarbon Analyses of Produced Well Stream - Mol Percent

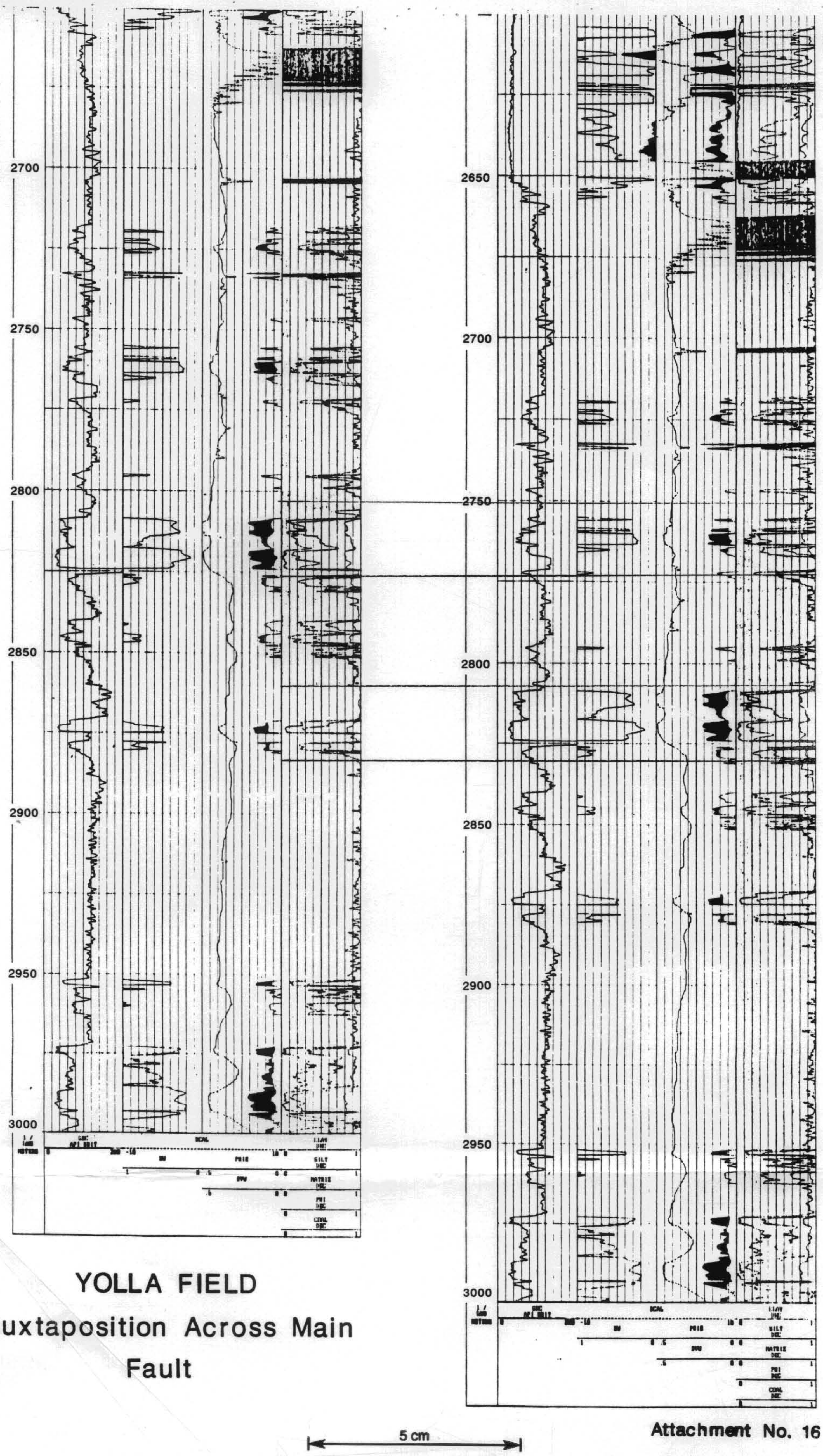
	Reservoir Pressure - psig							
Component	3~~2~~683 Dew	3200	2700	2100	1500	1000	500	500*
Hydrogen Sulphide	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Carbon Dioxide	18.86	18.89	18.91	18.91	18.93	18.97	19.00	3.38
Nitrogen	0.20	0.21	0.22	0.22	0.21	0.21	0.20	0.21
Methane	63.87	64.18	64.40	64.57	64.56	64.33	63.42	7.72
Ethane	7.64	7.63	7.63	7.64	7.66	7.68	7.74	2.01
Propane	3.75	3.73	3.72	3.73	3.75	3.78	3.84	2.08
iso-Butane	0.65	0.61	0.59	0.59	0.61	0.67	0.76	0.62
n-Butane	1.04	1.00	0.99	0.99	0.99	1.04	1.12	1.21
iso-Pentane	0.38	0.36	0.35	0.34	0.36	0.39	0.44	0.70
n-Pentane	0.39	0.37	0.36	0.36	0.38	0.41	0.46	0.85
Hexanes	0.54	0.53	0.51	0.50	0.51	0.52	0.60	1.88
Heptanes	0.74	0.72	0.71	0.71	0.70	0.71	0.75	3.94
Octanes	0.55	0.53	0.51	0.49	0.49	0.49	0.63	5.31
Nonanes	0.34	0.32	0.30	0.29	0.28	0.28	0.36	4.74
Decanes	0.21	0.19	0.18	0.16	0.15	0.15	0.25	4.35
Undecanes plus	0.84	0.73	0.62	0.50	0.42	0.37	0.43	61.00
	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molecular weight of heptanes plus	137	133	129	124	121	120	123	199
Density of heptanes plus	0.793	0.788	0.784	0.779	0.777	0.776	0.778	0.840
Deviation Factor-Z								
Equilibrium gas	0.907	0.898	0.896	0.906	0.923	0.945	0.972	
Two-phase	0.907	0.891	0.886	0.889	0.904	0.921	0.947	
Gas viscosity	0.0269	0.0240	0.0214	0.0188	0.0167	0.0153	0.0142	
Well Stream produced - Cumulative percent of initial	0	11.522	24.781	41.636	58.871	72.953	86.653	

* Composition of equilibrium liquid phase

Attachment No. 15

472075

472076



YOLLA FIELD
Juxtaposition Across Main Fault

Attachment No. 16

DELIVERABILITY

GWSP SIMULATION PROGRAM

INPUT:

- TEST DATA
- RESERVOIR PARAMETERS
  - PERMEABILITY
  - ORIGINAL GAS IN PLACE
  - TEMPERATURE
  - PRESSURE
  - DEPTH
- FLUID PROPERTIES
- WELLBORE CONFIGURATION
- WELL SPACING

OUTPUT:

- Z FACTOR CALCULATIONS AS FUNCTION OF PRESSURE
- YEARLY DELIVERABLITY, CUMULATIVE PRODUCTION, PRESSURE, P/Z
- RECOVERY FACTOR

CALCULATION:

$$Q=C^*(PF^2-PWF^2)^N$$

Q=RATE
C=DELIVERABILITY COEFFICEINT
PF=FORMATION PRESSURE
PWF=FLOWING WELLBORE PRESSURE
N=DELIVERABILITY EXPONENT

472078

Attachment No. 18

```
                         **** LISTING OF INPUT DATA ****
 CARD NO. 1 ..... (FIRST CONTROL CARD)
  PROBLEM     USER                           DATE                     PRINT
     1.       SUE SHARPE                     10/29/89                   1.
 CARD NO. 2 .....
  COMPANY                                DIVISION
  AMOCO PRODUCTION CO.                   ELAFE
 CARD NO. 3 .....
  WELL NAME                              WELL LOCATION
  YOLLA NO. 1                            BASS STRAIT
0 CARD NO. 4 .....
  COUNTY                      FIELD                     ZONE
  TASMANIA                    YOLLA                     LOWER ZONE
 CARD NO. 5 .....
  RPINT   RTEMP     TBASE     PBASE     DEPTH     SECTION   ANALYSIS   PLASTIC
  4200.    292.     90.00     14.70     9267.        3.         1.         0.
 CARD NOS. 6 THROUGH 10 (FLOW-STRING DATA STARTING FROM SURFACE)
                 FROM        TO        DIAMETER
  SECTION 1         0.     4000.          3.480
  SECTION 2      4000.     9056.          3.480
  SECTION 3      9056.     9267.          8.500
0 CARD NO. 12 .....(GAS COMPOSITION)
  NITROGEN   METHANE    CO2       ETHANE      H2S       PROPANE   I-BUTANE N-BUTANE
   0.00200  0.63870   0.18860   0.07640   0.00000   0.03750   0.00650  0.01040
 CARD NO. 13 .....(GAS COMPOSITION)
  I-PENTANE N-PENTANE  HEXANE     C+          AMC+      SPC+       PCC+     TCC+
   0.00380   0.00390  0.00540   0.02680      137.0   0.79800     370.0   1110.0
 CARD NO. 14 .....
  POROSITY   PERM     THICKNESS   SG        CUMGP     GINP      SPACING   WRADIUS
   0.1700  308.00      85.0     0.800      0.00    76681.      1300.     12.25
 CARD NO. 15 .....                                ** ABANDONMENT CRITERIA **
  DAY      MONTH      YEAR      DTIME      DCQ       QMIN      PABND     CUMTIME
   1.        1.      1990.      12.       ******    1.000     500.0       0.00
 CARD NO. 16 .....
  ALOAD    SMITH      TLINP     PLINE(1)  PLINE(2)  PLINE(3)  PLINE(4)  PLINE(5)
   1.00     1.0        2.        500.      500.        0.        0.        0.
0 CARD NO. 17 .....(DELIV. EQUATION 1)
  EQU.  EXPON    COEFC    TSTIM    PSHUT    QTST1    QTST2    QTST3    PBHP    PSURF
   1.   1.000  0.019985    3.5     4197.   15100.      0.       0.     4106.      0.
 CARD NO. 21 .....(LAST CONTROL CARD)
  ID
  99
```

AMOCO PRODUCTION CO.
ELAFE
10/29/89

REQUESTED BY..... SUE SHARPE
WELL NAME AND NO. YOLLA NO. 1
LOCATION S-T-R BASS STRAIT
COUNTY TASMANIA
FIELD YOLLA
ZONE LOWER ZONE

TABLE 1
CRITICAL PROPERTIES OF GAS

SPECIFIC GRAVITY OF C7 += 0.79800
MOLECULAR WEIGHT OF GAS = 28.23

COMP	MOLE WEIGHT	VAP. MOL FRACTION	CRITICAL PRES.,PSIA	CRITICAL TEMP., R	CRITICAL VOLUME
N2	28.016	0.00200	492.00	227.09	0.05140
C1	16.042	0.63870	669.70	343.13	0.09910
CO2	44.010	0.18860	1071.00	547.49	0.03430
C2	30.068	0.07640	708.30	549.77	0.07780
C3	44.094	0.03750	616.30	665.68	0.07280
IC4	58.120	0.00650	529.10	734.63	0.07240
NC4	58.120	0.01040	550.70	765.29	0.07020
IC5	72.146	0.00380	494.70	828.69	0.06850
NC5	72.146	0.00390	487.30	845.08	0.06900
C6	86.172	0.00540	436.60	913.14	0.06850
C7	137.000	0.02680	370.00	1110.00	0.00000

```
                 TABLE 2
GAS PROPERTIES AS A FUNCTION OF PRESSURE
  GAS GRAVITY          ,FRACT. =    0.97
  PSEUDO CRIT. PRESS,PSIA    =  733.16
  PSEUDO CRIT. TEMP.,DEG.R   =  443.69
PRESSURE  VISCOSITY  Z-FACTOR  * PHI
  (P)       (VIS)      (Z)
  PSIA       CP       FRACT.   FUNCTION
--------  ---------  --------  --------
   14.7   0.01623    0.9987        6664.
   81.1   0.01626    0.9933      203610.
  147.6   0.01630    0.9878      674923.
  214.0   0.01633    0.9823     1422453.
  280.4   0.01637    0.9769     2447899.
  346.9   0.01641    0.9716     3752722.
  413.3   0.01646    0.9663     5338044.
  479.7   0.01652    0.9611     7204558.
  712.2   0.01678    0.9439    15946431.
  944.8   0.01712    0.9296    28079168.
 1177.3   0.01754    0.9185    43480320.
 1409.8   0.01807    0.9060    61988720.
 1642.3   0.01875    0.8885    83458608.
 1874.8   0.01956    0.8723   107694944.
 2107.3   0.02046    0.8635   134340432.
 2339.9   0.02147    0.8592   162953248.
 2572.4   0.02261    0.8554   193159072.
 2804.9   0.02385    0.8534   224644464.
 3037.4   0.02513    0.8555   257096016.
 3269.9   0.02643    0.8613   290224384.
 3502.4   0.02773    0.8698   323806976.
 3735.0   0.02904    0.8801   357678848.
 3967.5   0.03036    0.8913   391714304.
 4200.0   0.03168    0.9036   425817600.
 4432.5   0.03297    0.9173   459914496.
* INTEGRAL OF P/(VIS*Z) IN (PSIA*PSIA/CP) UNITS.
```

```
                         TABLE 3
    DELIVERABILITY AS A FUNCTION OF RESERVOIR PRESSURE
                LINE PRESSURE =  500.0
 BOTTOM-HOLE   RESERVOIR        PHI          DELIV.
 PRES,PSIA     PRES,PSIA      FUNCTION       MSCFD
 -----------   ---------    ------------    ------
     667.2        667.4     0.139958E+08      0.00
     791.5        899.5     0.254563E+08   6375.00
    1077.1       1237.4     0.479733E+08  12750.00
    1421.8       1609.9     0.802931E+08  19125.00
    1782.4       1991.3     0.120772E+09  25500.00
    2142.9       2374.7     0.167384E+09  31875.00
    2501.6       2759.1     0.218360E+09  38250.00
    2857.6       3144.1     0.272227E+09  44625.00
    3213.6       3532.7     0.328207E+09  51000.00
    3569.5       3924.3     0.385371E+09  57375.00
    3928.4       4321.8     0.443560E+09  63750.00
                        ==000==
```

```
                LINE PRESSURE =  500.0
 BOTTOM-HOLE   RESERVOIR        PHI          DELIV.
 PRES,PSIA     PRES,PSIA      FUNCTION       MSCFD
 -----------   ---------    ------------    ------
     667.2        667.4     0.139958E+08      0.00
     791.5        899.5     0.254563E+08   6375.00
    1077.1       1237.4     0.479733E+08  12750.00
    1421.8       1609.9     0.802931E+08  19125.00
    1782.4       1991.3     0.120772E+09  25500.00
    2142.9       2374.7     0.167384E+09  31875.00
    2501.6       2759.1     0.218360E+09  38250.00
    2857.6       3144.1     0.272227E+09  44625.00
    3213.6       3532.7     0.328207E+09  51000.00
    3569.5       3924.3     0.385371E+09  57375.00
    3928.4       4321.8     0.443560E+09  63750.00
                        ==000==
```

```
                                                                  PAGE 4
                 AMOCO PRODUCTION CO.
                 ELAFE
                 10/29/89

     WELL NAME AND NO.    YOLLA NO. 1
     LOCATION S-T-R       BASS STRAIT
     COUNTY               TASMANIA
     FIELD                YOLLA
     ZONE                 LOWER ZONE

   I. RESERVOIR AND WELL DATA -------------------------
     INITIAL RESERVOIR PRESSURE   ,PSIA   = 4200.
     CURRENT RESERVOIR PRESSURE   ,PSIA   = 4200.
     RESERVOIR TEMPERATURE        ,DEG.F =  292.
     BASE TEMPERATURE             ,DEG.F =   90.
     BASE PRESSURE                ,PSIA   =   15.
0    AVERAGE GAS PERMEABILITY     ,MD     =  308.000
     AVERAGE POROSITY             ,FRACT.=     0.17
     AVERAGE FORMATION THICKNESS  ,FEET   =   85.00
     AVERAGE GAS SATURATION       ,FRACT.=     0.80
0    WELL DEPTH                   ,FEET   = 9267.
     WELL SPACING                 ,ACRES = 1300.
     WELL RADIUS                  ,INCHES=    12.25
     RESERVOIR RADIUS             ,FEET   = 4246.
0    DAILY CONTRACT RATE          ,MMCFD =  100.000
     LOAD FACTOR                  ,FRACT.=     1.000
     ABANDONMENT RATE             ,MMCFD.=     1.000
     ABANDONMENT PRESSURE         ,PSIA .=  500.
     ABANDONMENT TIME             ,YEARS =     0.00
     RESULTS PRINTED EVERY         MONTH =   12.
   II. PRESSURE DROP CALCULATIONS WERE MADE BY -------
     ** CULLENDER AND SMITH METHOD **
0  DIVIDE THE FLOW-STRING( STEEL ) AS FOLLOWS .....
     FLOW STRING      LENGTH(FT)      DIAM
       SECTION      FROM      TO     INCHES
     ----------- ------  ------  ------
          1          0.0  4000.0   3.480
          2       4000.0  9056.0   3.480
          3       9056.0  9267.0   8.500
0III. TYPE OF DELIVERABILITY EQUATION ----
               2    2 N                          TEST DATA
     Q = C*( PF -PWF )  .....EQ.1, TIME =   3.5 HOURS,  RATE = 15100. MCFD

  EQUATION IN TERMS OF       N           C
   P-SQUARED               1.000     0.01998495   UNSTABILIZED
  *PHI FUNCTION            1.000     0.00113362   UNSTABILIZED
  *PHI FUNCTION            1.000     0.00110730   STABILIZED

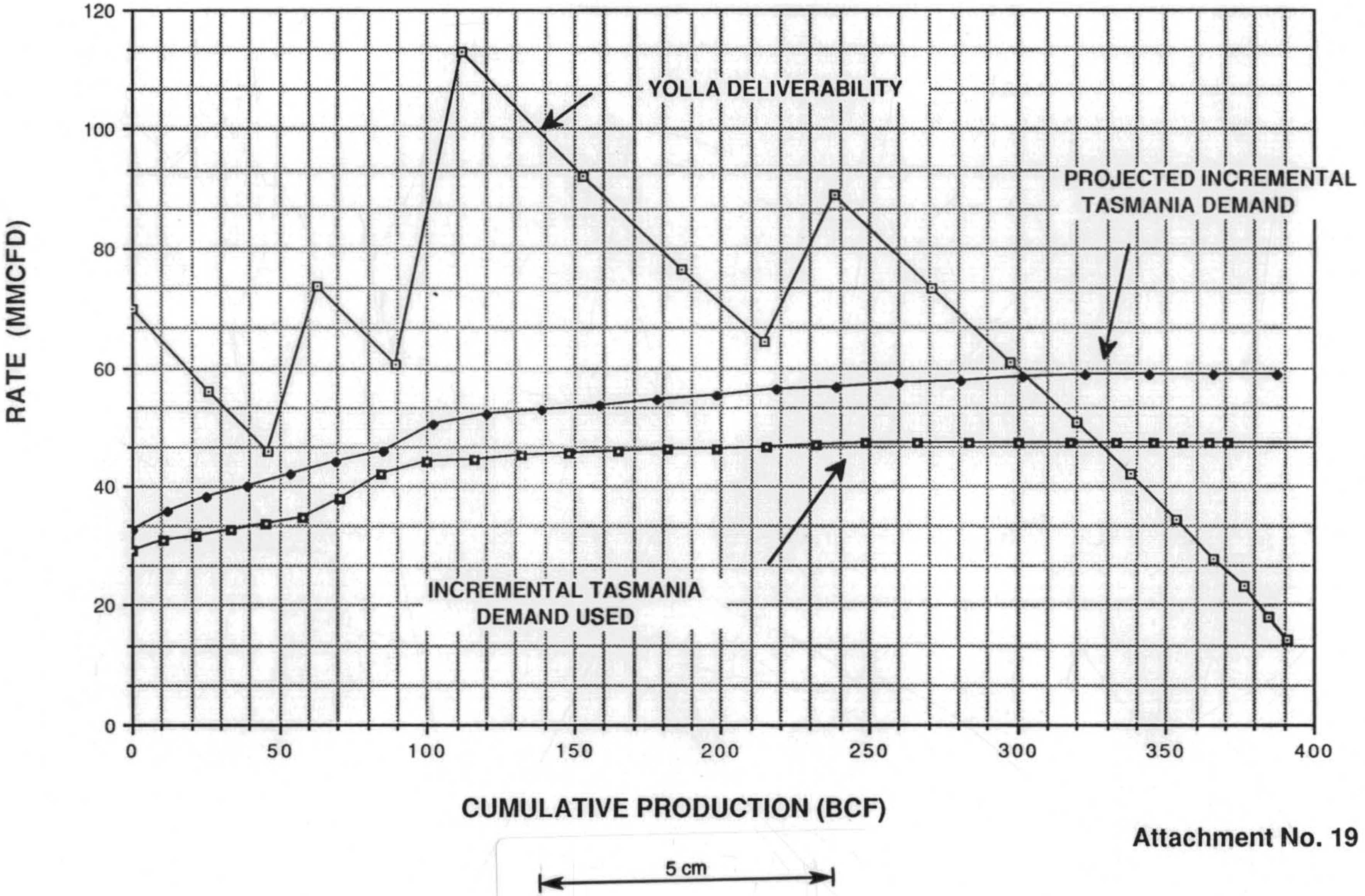
  WHERE, N = DELIV. EXPONENT, C = DELIV. COEFFICIENT
          *PHI IS AN INTEGRAL OF P/(VIS*Z)
```

```
   YOLLA NO. 1                                                                     PAGE 5
                                         STABILIZED PERFORMANCE PREDICTION
0                                   INITIAL GAS IN PLACE,MMSCF =     76680.9803
                                    INITIAL PRESSURE     ,PSIA   =      4200.
     TIME        DELIV       RATE      CUM.   GAS              PRESSURE,   PSIA                  RATIO
MON DY YEAR      MMCFD       MMCFD    PROD.,MMSCF      SURFACE BOTTOM-HOLE RESERVOIR              P/Z
--- -- ----     -----       -----    -----------      ------- ----------- ---------             -----
JAN  1 1990 61.821      61.821              0.00        500.0      3819.9      4200.0          4648.1
JAN  1 1991 42.148      42.148          18889.73        500.0      2719.8      2994.5          3503.1
JAN  1 1992 30.882      30.882          32254.42        500.0      2086.8      2314.9          2693.0
JAN  1 1993 22.851      22.851          42121.39        500.0      1632.0      1832.4          2094.9
JAN  1 1994 17.045      17.045          49449.19        500.0      1306.3      1486.6          1650.7
JAN  1 1995 12.322      12.322          54851.15        500.0      1055.3      1213.2          1323.2
JAN  1 1996  8.589       8.589          58695.68        500.0       879.1      1009.9          1090.2
JAN  1 1997  5.717       5.717          61333.41        500.0       768.8       868.8           930.3
JAN  1 1998  3.553       3.553          63039.39        500.0       708.4       776.9           826.9
JAN  1 1999  2.001       2.001          64058.75        500.0       680.7       721.7           765.1
JAN  1 2000  1.006       1.006          64607.24        500.0       670.7       691.9           731.9
FEB  1 2000  0.944       0.944          64638.43        500.0       670.3       690.2           730.0
JAN  1 2001  0.449       0.449          64870.74        500.0       667.9       677.5           715.9
JAN  1 2002  0.185       0.185          64983.98        500.0       667.3       671.3           709.0
JAN  1 2003  0.073       0.073          65029.77        500.0       667.2       668.8           706.3
JAN  1 2004  0.028       0.028          65047.63        500.0       667.2       667.8           705.2
JAN  1 2005  0.011       0.011          65054.50        500.0       667.2       667.5           704.8
MAR  1 2005  0.009       0.009          65055.11        500.0       667.2       667.4           704.7
0                       GAS RECOVERY UPTO*MAR 1,2005* =  84.84  PER-CENT


 ** NOTE ** SINCE      RESERVOIR PRESSURE    =  667.4  PSIA ,HAS FALLEN BELOW THE
 **********            ABANDONMENT PRESSURE =  667.4  PSIA , PROGRAM IS STOPPED.
```

472084

YOLLA DELIVERY
VS
TASMANIA DEMAND



Attachment No. 19

Attachment No. 20

YOLLA DEVELOPMENT
CAPITAL COST SUMMARY

ITEM	$MM
Jacket, Deck Conductors, Piling and Slots	21.69
Equipment Modules, Quarters and Helipad	24.94
Offshore Installation with Derrick Barge	35.18
Offshore Hook-up on Platform	2.40
Offshore Pipeline	85.44
Development Drilling	112.50
Site Investigations, Certification, Preliminary Studies	1.0
Onshore Pipeline	1.1
Onshore Gas Plant	5.86
Helipad and Marine Base	8.23
Construction Insurance (1%)	1.85
Project contingency (20%)	42.98
Allowance for Industrial Unrest	4.5
Total	**347.67**

Attachment No. 21

PRELIMINARY CAPITAL COST DIFFERENCES(1) BETWEEN ONSHORE & OFFSHORE COMPRESSION

ITEM	OFFSHORE	ONSHORE
° Compression Facilities	-	2,300
° Submarine Pipeline, offshore 323, onshore 508mm		
- Materials	-	11,840
- Installation	-	16,800
° Platform	2,060	-
TOTAL:	2,060	30,940

NOTE(1): Capital Cost Differences refers to the difference in capital cost to install equipment or facilities over and above the lowest cost option. For example, Case 1 with offshore compression requires a 323mm submarine pipeline but a 508mm pipeline is required for the onshore compression option. The additional capital to install the 508mm pipeline over the 323mm pipeline of $28,640K is the "Capital Cost Difference".

* Data from Table 3.5 of Development Study, Yolla Gas Field by R.J. Brown-CMPS

10

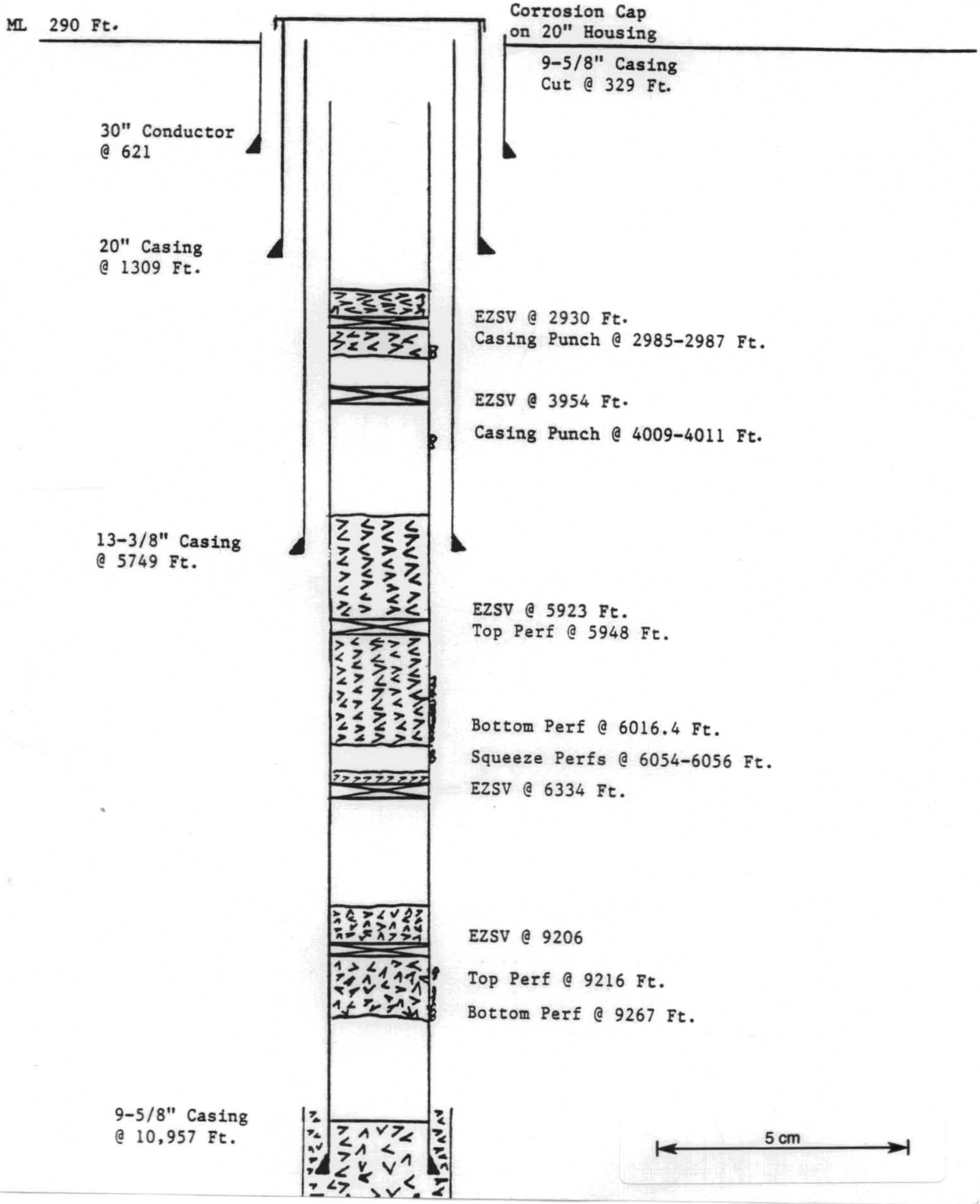
YOLLA NO. 1.

ABANDONMENT DIAGRAM

472087

All Depths
RKB

Attachment No. 22



OPERATING COSTS

ITEM	A$MM/YR	COMMENTS
WELL REPAIR	0.50-1.50	$0.25MM/WELL EVERY OTHER YR
PLATFORM OPERATIONS	5.88	MANNED PLATFORM ($1.9MM FOR UNMANNED)
ONSHORE PIPELINE & PLANT	0.78	1 OPERATOR WITH SUB-CONTRACT FOR OVERHALL/MODIFICATION/SUPPORT
TRANSPORTATION	8.10	MANNED PLATFORM ($1.21MM FOR UNMANNED)
INSURANCE	0.55	0.5%,0.3%,0.2% FOR PLATFORM, PIPELINE, ONSHORE PLANT &LINES, RESPECTIVELY
INDIRECT - PRODUCING PHASE	0.3	
TOTAL	**16.11-17.11**	

Attachment No. 24

GIPPSLAND BASIN OPERATING COST COMPARISON CALCULATION

Gippsland Basin estimated gross 1989 operating expense and gas production:*

A$120 MM/yr, 478.9 MMCFD

Average cost per MMCFD:

$120/478.9 MMCFD = $0.25 MM/MMCFD

Operating expense for Yolla at peak rate based on Gippsland costs:

(40 MMCFD)(0.25) = **A$10.0 MM/yr**

Gippsland unit cost on a barrels of oil equivalent basis:

[(478.8 MMCFD)/(5.8 MMCFD/BOED)]+[335.1 MBOPD] = 417.7 MBOED

$120/417.7 MBOED = $0.29 MM/MBOED

Yolla expense on Gippsland BOE basis:

[(40 MMCFD)/(5.8 MMCFD/BOED)]+[3 MMBCPD] = 9.9 MBOED

(9.9)(0.29) = **$2.9 MM/yr**

* Data from WoodMac Business Publications, June 1989

Attachment No. 25

TASMANIAN POWER STATIONS IN SERVICE - 1988.

Hydro Scheme	Power Station	Generating Units	Total Capacity MW	Install Date
Derwent	Tarraleah	6 x 15	90	1938
	Butlers Gorge	1 x 12	12	1951
	Tungatinah	5 x 25	125	1953
	Lake Echo	1 x 32	32	1956
	Wayatinah	3 x 13	38	1957
	Liapootah	3 x 28	84	1960
	Catagunyah	2 x 24	48	1962
	Meadowbank	1 x 40	40	1967
	Repulse	1 x 28	28	1968
	Cluny	1 x 17	17	1968
Great Lake	Waddamana B	4 x 12	48	1944
	Trevallyn	4 x 20	80	1955
	Poatina	6 x 50	300	1964
	Tods Corner	1 x 2	2	1966
Mersey-Forth	Rowallan	1 x 10	10	1968
	Lemonthyme	1 x 51	51	1969
	Devils Gate	1 x 60	60	1969
	Wilmot	1 x 31	31	1971
	Cethana	1 x 85	85	1971
	Paloona	1 x 28	28	1972
	Fisher	1 x 43	43	1973
Gordon	Gordon 1 & 2	2 x 144	288	1978
	Gordon 3	1 x 144	144	1988
Pieman	Mackintosh	1 x 80	80	1982
	Bastyan	1 x 80	80	1984
	Reece	2 x 116	232	1986
Total Hydro			**2,076**	
Thermal	Bell Bay	2 x 120	240	1971 1975
Total			**2,316**	

* Data from Table 2.1 of P.M. Garlick & Assoc report; included in Appendix 3

TASMANIAN ELECTRICITY SALES BY CATEGORY (GWh)*

Fiscal Year	Domestic[1]	Commerical[2]	General Industrial[3]	Major Industrial[4]	Total
1979	1462	180	652	4709	7003
1980	1538	191	691	4760	7180
1981	1569	197	710	4716	7191
1982	1662	235	599	4900	7396
1983	1672	251	558	4772	7253
1984	1693	258	596	4849	7395
1985	1733	270	558	4943	7504
1986	1762	285	600	5029	7677
1987	1821	302	613	4944	7681
1988	1768	322	647	5382	8119

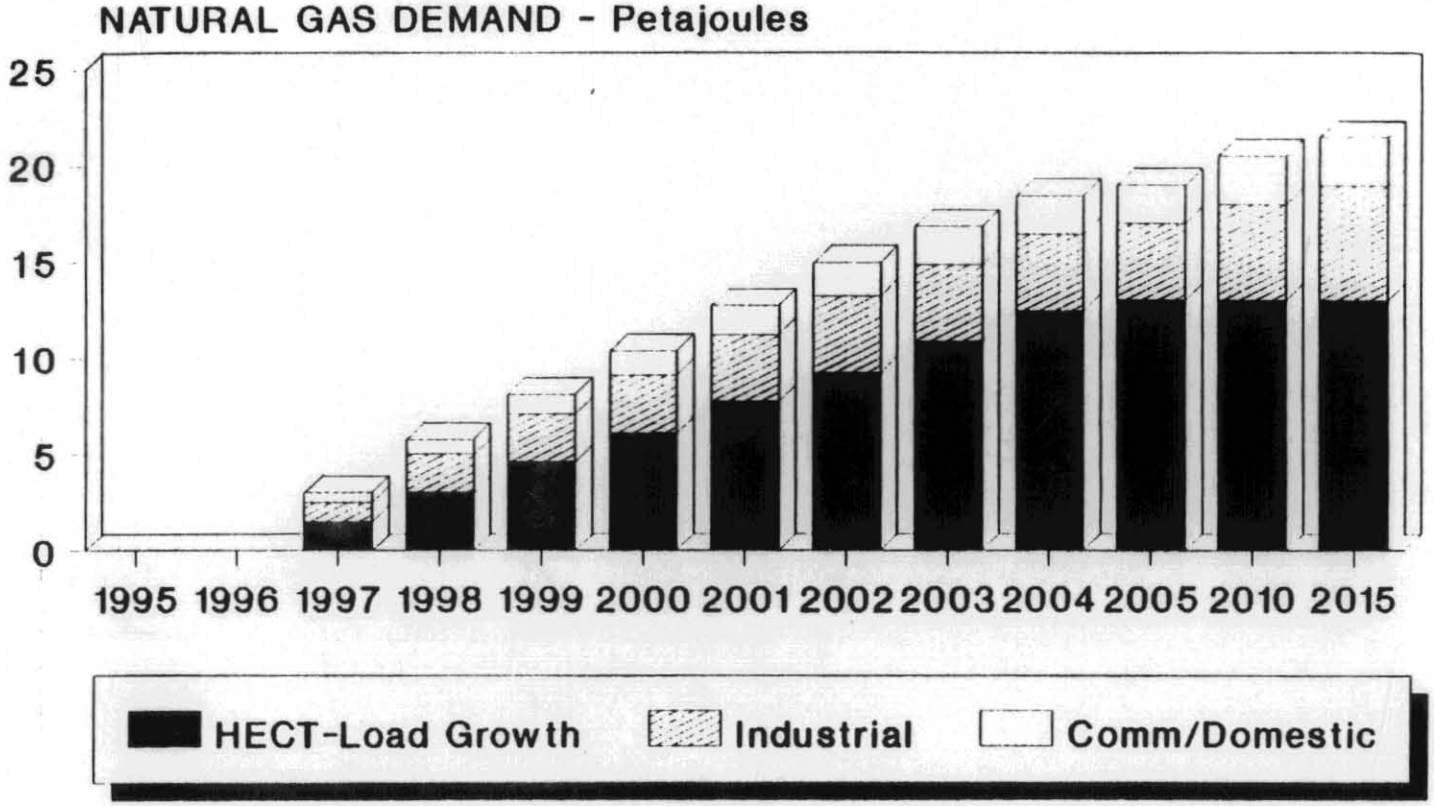
1. Includes residential, Hot Water and Off Peak
2. Includes Commercial and Bulk Commercial
3. Includes Industrial, Unread Meters, and HECT Villages
4. Includes major Industrial Customers Only

* Table from Table 3.2 of P.M. Garlick & Assoc report; included in Appendix 3

Attachment No. 26

NATURAL GAS FOR TASMANIA

Gas Market Development
With No New Industries



* Data from Figure 2 of Appendix 3

Attachment No. 27

NATURAL GAS MARKET DEVELOPMENT WITHOUT NEW TASMANIAN INDUSTRIES

	Electricity Demand Growth	Industrial Users	Commercial /Domestic Users	Total
	----------------- PJ per year -----------------			
1995	0	0	0	0
1996	0	0	0	0
1997	1.5	1.0	0.5	3.0
1998	3.0	2.0	0.7	5.7
1999	4.6	2.5	1.0	8.1
2000	6.1	3.0	1.2	10.3
2001	7.7	3.5	1.5	12.7
2002	9.2	4.0	1.7	14.9
2003	10.8	4.0	2.0	16.8
2004	12.4	4.0	2.0	18.4
2005	13.0	4.0	2.0	19.0
2010	13.0	5.0	2.5	20.5
2015	13.0	6.0	2.5	21.5

NATURAL GAS MARKET DEVELOPMENT WITH HECT DEMAND AT MINIMUM OF 80%

	Total With Normal Electricity Demand Growth	Additional HECT Demand to 80%	Total
	----------------- PJ per year -----------------		
1995	0	0	0
1996	0	0	0
1997	3.0	8.9	11.9
1998	5.7	7.4	13.1
1999	8.1	5.8	13.9
2000	10.3	4.3	14.6
2001	12.7	2.7	15.4
2002	14.9	1.2	16.1
2003	16.8	0	16.8
2004	18.4	0	18.4
2005	19.0	0	19.0
2010	20.5	0	20.5
2015	21.5	0	21.5

YOLLA FIELD DEVELOPMENT ECONOMIC SUMMARY

Currency in Australian Dollars (1.27A$/US$)

Assumptions

Participating Interest, %	100
Gross Gas Reserves, PJ	411
Gross Liquid Reserves, MMBL	22
Gross Investment, $MM	354
Prices (1990)	
Gas, $GJ	5.00
Liquids, $/BBL	21.00
Price Escalation, %/Yr	
Gas, %/Yr	8
Liquids, %/Yr	4
Cost Escalation, %/Yr	8

Fiscal Terms

Corporate Income Tax Rate, %	39
Resource Rent Tax, %	40
Threshold Rate, %	28
Depreciation, Straight Line, Years	10

Net Economic Results

Internal Rate of Return, %	20
Undiscounted Cash Flow, $MM	4,977

YOLLA GAS FIELD DEVELOPMENT
Financial Analysis
(Australian Dollars, Millions)

CASH FLOWS INCLUDING ESCALATION

YEAR	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
REVENUE																
Gas Sales, PJ/Y				10.6	11.2	11.6	12.0	12.4	12.7	13.8	15.4	16.0	16.1	16.3	16.5	16.6
Liquid Sales, MMB/Y				0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.9	0.9	0.9	0.9	0.9
Gas Price, $/GJ	6.80	7.35	7.93	8.57	9.25	10.00	10.79	11.66	12.59	13.60	14.69	15.86	17.13	18.50	19.98	21.58
Liquid Price, $/BBL	24.57	25.55	26.57	27.63	28.74	29.89	31.09	32.33	33.62	34.97	36.37	37.82	39.33	40.91	42.54	44.24
Gas Revenue, $MM				91.0	104.0	116.0	129.2	144.3	160.4	187.6	226.2	253.6	276.4	301.2	328.9	358.4
Liquid Revenue, $MM				15.8	17.4	18.8	20.1	21.6	23.1	26.0	30.3	32.7	34.3	36.0	37.9	39.7
TOTAL REVENUE				106.9	121.5	134.8	149.3	165.8	183.5	213.6	256.5	286.3	310.7	337.1	366.8	398.1
EXPENSES																
Total Operating Costs	1.7	7.5	13.6	31.7	34.4	37.2	40.2	43.4	49.3	50.6	56.3	59.0	72.5	68.8	76.6	85.2
Depreciation				11.5	12.5	12.9	13.3	13.7	15.1	17.5	19.5	20.3	24.7	29.2	29.5	29.8
Abandonment																
TOTAL EXPENSES	1.7	7.5	13.6	43.3	46.9	50.0	53.4	57.1	64.5	68.1	75.9	79.3	97.2	98.0	106.2	115.0
INCOME BEFORE TAXES	-1.7	-7.5	-13.6	63.6	74.6	84.7	95.9	108.8	119.0	145.6	180.6	207.0	213.5	239.1	260.6	283.1
AUSTRALIAN TAXES																
Resource Rent Tax																
Corporate Income Tax				20.1	16.8	21.0	25.5	30.8	35.3	44.6	59.1	69.7	73.8	88.9	106.4	115.4
TOTAL TAXES				20.1	16.8	21.0	25.5	30.8	35.3	44.6	59.1	69.7	73.8	88.9	106.4	115.4
CASH FLOW																
Income After Taxes	-1.7	-7.5	-13.6	43.5	57.8	63.8	70.4	78.0	83.7	101.0	121.5	137.3	139.7	150.2	154.2	167.7
Plus:																
Non-Cash Charges				11.5	12.5	12.9	13.3	13.7	15.1	17.5	19.5	20.3	24.7	29.2	29.5	29.8
Less:																
Capital Investments	16.8	142.8	276.1	18.8					55.4				150.7			
CASH FLOW	-18.6	-150.3	-289.7	36.2	70.2	76.6	83.6	91.7	43.5	118.5	141.0	157.5	13.7	179.4	183.7	197.4
CUM CASH FLOW	-18.6	-168.9	-458.6	-422.4	-352.2	-275.6	-191.9	-100.2	-56.7	61.8	202.8	360.4	374.0	553.5	737.2	934.7

YEAR	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	TOTAL
REVENUE																	
Gas Sales, PJ/Y	16.8	16.9	16.9	17.0	17.2	17.2	17.2	17.2	17.2	17.2	15.3	12.6	10.2	8.5	6.7	5.1	410.5
Liquid Sales, MMB/Y	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.7	0.5	0.5	0.4	0.3	22.2
Gas Price, $/GJ	23.30	25.17	27.18	29.36	31.71	34.24	36.98	39.94	43.14	46.59	50.31	54.34	58.69	63.38	68.45	73.93	
Liquid Price, $/BBL	46.01	47.85	49.77	51.76	53.83	55.98	58.22	60.55	62.97	65.49	68.11	70.84	73.67	76.62	79.68	82.87	
Gas Revenue, $MM	390.4	424.4	460.4	500.4	543.9	589.9	637.1	688.1	743.1	802.6	769.5	684.3	599.8	536.7	457.2	380.5	11885.4
Liquid Revenue, $MM	41.7	43.5	45.6	47.6	49.9	52.1	54.2	56.4	58.6	61.0	56.2	48.1	40.3	36.4	29.1	24.2	1098.4
TOTAL REVENUE	432.1	467.9	506.0	548.0	593.8	642.0	691.3	744.4	801.8	863.5	825.7	732.3	640.1	573.1	486.3	404.7	12983.8
EXPENSES																	
Total Operating Costs	89.4	99.4	109.6	116.0	125.2	135.3	146.1	157.8	170.4	184.0	198.7	214.6	231.8	250.4	270.4	292.0	3519.2
Depreciation	30.0	30.2	35.8	41.4	41.7	41.9	41.9	41.9	41.9	41.9	37.2	30.6	24.8	20.7	16.3	12.6	780.3
Abandonment																248.0	248.0
TOTAL EXPENSES	119.4	129.6	145.4	157.4	167.0	177.2	188.0	199.7	212.3	225.9	235.9	245.3	256.6	271.1	286.7	552.6	4547.5
INCOME BEFORE TAXES	312.7	338.3	360.5	390.6	426.9	464.9	503.3	544.8	589.5	637.6	589.7	487.1	383.5	302.0	199.6	-147.9	8436.3
AUSTRALIAN TAXES																	
Resource Rent Tax																	
Corporate Income Tax	127.1	137.3	149.1	159.9	174.3	189.4	207.5	226.8	244.4	263.4	243.2	200.8	160.8	130.1	88.7	48.8	3459.1
TOTAL TAXES	127.1	137.3	149.1	159.9	174.3	189.4	207.5	226.8	244.4	263.4	243.2	200.8	160.8	130.1	88.7	48.8	3459.1
CASH FLOW																	
Income After Taxes	185.5	200.9	211.4	230.7	252.6	275.5	295.8	318.0	345.0	374.2	346.6	286.2	222.7	171.9	110.9	-196.8	4977.2
Plus:																	
Non-Cash Charges	30.0	30.2	35.8	41.4	41.7	41.9	41.9	41.9	41.9	41.9	37.2	30.6	24.8	20.7	16.3	12.6	780.3
Less:																	
Capital Investments			119.6														780.3
CASH FLOW	215.6	231.2	127.6	272.1	294.3	317.4	337.7	359.9	386.9	416.1	383.7	316.9	247.5	192.6	127.2	-184.1	4977.2
CUM CASH FLOW	1150.2	1381.4	1509.0	1781.2	2075.4	2392.8	2730.6	3090.5	3477.4	3893.5	4277.2	4594.1	4841.6	5034.2	5161.4	4977.2	

Attachment No. 29

YOLLA GAS FIELD DEVELOPMENT
Financial Analysis
(Australian Dollars, Millions)

UNESCALATED CAPITAL INVESTMENTS AND OPERATING COSTS

YEAR	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	TOTAL	TOTAL ESCAL.
GROSS CAPITAL INVESTMENT																																		
Development Drilling	10.2		12.7	10.2					20.4				40.7						20.4														114.6	381.3
Engineering	1.3																																1.3	1.9
Platform		55.9	29.9																														85.7	139.8
Pipeline		29.0	58.0																														87.0	145.4
Onshore Facilities		5.2	10.3																														15.5	25.8
Insurance, Contingency			50.2																														50.2	86.1
TOTAL CAPITAL INVESTMENT	11.5	90.0	161.1	10.2					20.4				40.7						20.4														354.2	780.3
OPERATING COSTS																																		
Well Repair					0.5	0.5	0.5	0.5	0.5	0.5	1.0	0.5	1.0	0.5	1.0	1.5	1.0	1.5	1.0	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	32.1	257.3
Operations				6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	173.5	1151.1
Pipeline & Plant				0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	23.3	154.8
Transportation				8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	239.2	1587.1
Insurance				0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	16.2	107.8
Indirect Operating & Admin	0.6	0.6	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	13.0	76.5
Overhead	0.5	4.1	7.3	1.2	0.7	0.7	0.7	0.7	1.7	0.7	0.8	0.7	2.6	0.7	0.8	0.8	0.8	0.8	1.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	38.3	185.2
TOTAL OPERATING COSTS	1.2	4.7	7.9	17.2	17.2	17.2	17.2	17.2	18.1	17.2	17.8	17.2	19.6	17.2	17.8	18.3	17.8	18.3	18.7	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	535.6	3519.9
ABANDONMENT COSTS																																25.5	25.5	407.2

YOLLA GAS FIELD DEVELOPMENT
Financial Analysis
(Australian Dollars, Millions)

ESCALATED CAPITAL INVESTMENTS AND OPERATING COSTS

YEAR	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	TOTAL
GROSS CAPITAL INVESTMENT																																	
Development Drilling	15.0		21.8	18.8					55.4				150.7						119.6														381.3
Engineering	1.9																																1.9
Platform		88.6	51.2																														139.8
Pipeline		46.0	99.4																														145.4
Onshore Facilities		8.2	17.7																														25.8
Insurance, Contingency			86.1																														86.1
TOTAL CAPITAL INVESTMENT	16.8	142.8	276.1	18.8					55.4				150.7						119.6														780.3
OPERATING COSTS																																	
Well Repair					1.0	1.1	1.2	1.3	1.4	1.5	3.2	1.7	3.8	2.0	4.4	7.1	5.1	8.3	6.0	9.7	10.5	11.3	12.2	13.2	14.2	15.4	16.6	17.9	19.4	20.9	22.6	24.4	257.3
Operations				11.1	12.0	12.9	13.9	15.1	16.3	17.6	19.0	20.5	22.1	23.9	25.8	27.9	30.1	32.5	35.1	37.9	41.0	44.2	47.8	51.6	55.7	60.2	65.0	70.2	75.8	81.9	88.4	95.5	1151.1
Pipeline & Plant				1.5	1.6	1.7	1.9	2.0	2.2	2.4	2.6	2.8	3.0	3.2	3.5	3.8	4.1	4.4	4.7	5.1	5.5	6.0	6.4	6.9	7.5	8.1	8.7	9.4	10.2	11.0	11.9	12.8	154.8
Transportation				15.3	16.5	17.8	19.2	20.8	22.4	24.2	26.2	28.3	30.5	33.0	35.6	38.4	41.5	44.8	48.4	52.3	56.5	61.0	65.9	71.2	76.8	83.0	89.6	96.8	104.5	112.9	121.9	131.7	1587.1
Insurance				1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.8	1.9	2.1	2.2	2.4	2.6	2.8	3.0	3.3	3.6	3.8	4.1	4.5	4.8	5.2	5.6	6.1	6.6	7.1	7.7	8.3	8.9	107.8
Indirect Operating & Admin	0.9	1.0	1.1	0.7	0.8	0.8	0.9	1.0	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.8	1.9	2.1	2.2	2.4	2.6	2.8	3.1	3.3	3.6	3.8	4.1	4.5	4.8	5.2	5.6	6.1	76.5
Overhead	0.8	6.5	12.5	2.2	1.5	1.6	1.7	1.9	4.5	2.2	2.4	2.5	9.6	3.0	3.3	3.7	3.8	4.3	9.9	5.0	5.4	5.8	6.3	6.8	7.3	7.9	8.6	9.2	10.0	10.8	11.6	12.6	185.2
TOTAL OPERATING COSTS	1.7	7.5	13.6	31.7	34.4	37.2	40.2	43.4	49.3	50.6	56.3	59.0	72.5	68.8	76.6	85.3	89.4	99.4	109.7	116.0	125.3	135.3	146.1	157.8	170.4	184.1	198.8	214.7	231.9	250.4	270.4	292.1	3519.9
ABANDONMENT COSTS																																407.2	407.2

472097

YOLLA GAS FIELD DEVELOPMENT
Financial Analysis
(US Dollars, Millions)

UNESCALATED CAPITAL INVESTMENTS AND OPERATING COSTS

YEAR	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
GROSS CAPITAL INVESTMENT																
Development Drilling	8.0		10.0	8.0					16.0				32.0			
Engineering	1.0															
Platform		43.9	23.5													
Pipeline		22.8	45.6													
Onshore Facilities		4.1	8.1													
Insurance, Contingency			39.5													
TOTAL CAPITAL INVESTMENT	9.0	70.7	126.6	8.0					16.0				32.0			
OPERATING COSTS																
Well Repair					0.4	0.4	0.4	0.4	0.4	0.4	0.8	0.4	0.8	0.4	0.8	1.2
Operations				4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Pipeline & Plant				0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Transportation				6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Insurance				0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Indirect Operating & Admin	0.5	0.5	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Overhead	0.4	3.2	5.7	0.9	0.6	0.6	0.6	0.6	1.3	0.6	0.6	0.6	2.0	0.6	0.6	0.6
TOTAL OPERATING COSTS	0.9	3.7	6.2	13.5	13.5	13.5	13.5	13.5	14.3	13.5	14.0	13.5	15.4	13.5	14.0	14.4
ABANDONMENT COSTS																

YEAR	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	TOTAL	TOTAL ESCAL.
GROSS CAPITAL INVESTMENT																		
Development Drilling			16.0														90.0	299.6
Engineering																	1.0	1.5
Platform																	67.4	109.9
Pipeline																	68.4	114.3
Onshore Facilities																	12.2	20.3
Insurance, Contingency																	39.5	67.6
TOTAL CAPITAL INVESTMENT			16.0														278.3	613.1
OPERATING COSTS																		
Well Repair	0.8	1.2	0.8	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	25.2	202.2
Operations	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	136.3	904.4
Pipeline & Plant	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	18.3	121.6
Transportation	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	187.9	1246.9
Insurance	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	12.8	84.7
Indirect Operating & Admin	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	10.2	60.1
Overhead	0.6	0.6	1.3	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	30.1	145.5
TOTAL OPERATING COSTS	14.0	14.4	14.7	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	420.8	2765.5
ABANDONMENT COSTS																20.0	20.0	319.9

Attachment No. 30

ABBREVIATIONS

Reserves:

Million Cubic Feet of Gas	MMCFG
Billion Cubic Feet of Gas	BCFG
Thousand Barrels of Oil	MBO
Million Barrels of Oil	MMBO
Thousand Barrels of Liquid	MBL
Million Barrels of Liquid	MMBL
Thousand Barrels of Condensate	MBC
Million Barrels of Condensate	MMBC
Thousand Barrels of Oil Equivalent	MBOE
Million Barrels of Oil Equivalent	MMBOE

Rates:

Million Cubic Feet of Gas per Day	MMCFD
Thousand Barrels of Oil per Day	MBOPD
Barrels of Oil per Day	BOPD
Thousand Barrels of Liquid per Day	MBLPD
Barrels of Liquid per Day	BLPD
Thousand Barrels of Condensate per Day	MBCPD
Barrels of Condensate per Day	BCPD
Barrels of Oil Equivalent per Day	BOED
Thousand Barrels of Oil Equivalent per Day	MBOED

Value:

Billion	B
Million	MM
Thousand	M

Other:

Standard Cubic Feet	SCF
Pounds per Square Inch	psi
Megawatt	MW
Gigawatt hour	GWh
Petajoule	PJ
Gigajoule	GJ
Acres	ac
meters	m
Kilometers	km

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2. G.L. Chierici, G.M. Cuicci, and G. Long, "Experimental Research on Gas Saturation Behind the Water Front in Gas Reservoirs Subjected to Water Drive", Paper 17, Proc., 6th World Petroleum Congress, Section II, 483.

472100

APPENDICES

NO.	DESCRIPTION
1	Australia Yolla No. 1 Log Analysis
2	Development Study, Yolla Gas Field
3	Natural Gas for Tasmania; An Analysis of the Market Potential for Natural Gas

APPENDIX 1

472101

AUSTRALIA YOLLA #1
(97-033-03789-00)

LOG ANALYSIS

by

Robert L. Terry
August 16, 1989

Houston General Office - Exploration Technical Services

Formation Evaluation Department

472102

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OBJECTIVE

The purpose of this analysis was to evaluate the Yolla #1 well drilled by the Amoco Australia Petroleum Company to determine water saturations, shale volumes and net to gross reservoir porosity figures. This well lies to the North of Tasmania in the Bass Strait between mainland Australia and Tasmania (see Figure 1). The analysis was conducted over the Eastern View Group formation which spans the Upper Cretaceous, Paleocene and Lower Eocene (see Figure 2). This formation is typically comprised of intermixed sand, shale and coal beds.

SUMMARY

This well was drilled in 1985 with an fresh water "Aquagel" polymer mud system. The borehole was in poor condition throughout the zone of interest with numerous washouts and considerable hole rugosity. The wireline service company was Schlumberger and the logging tools run were as follows:

ISF......Induction Spherically Focused
MSFL.....Micro Spherically Focused Log
BHC......Borehole Compensated Sonic
LDL......Litho Density Log
CNL......Compensated Neutron Log
GR.......Gamma Ray
HDT......High Resolution Dipmeter Tool
RFT......Repeat Formation Tester
VSP......Vertical Seismic Profile Tool

also NGS, EPT

The log data used for this analysis was recovered from Master File. The digital data did not include the repeat formation tester measurements.

The environmentally corrected deep induction resistivity measurement was chosen as the closest approximation to Rt (true formation resistivity). This was due to the borehole washout and rugosity effects on the MSFL pad and the fact that the ISF was run in combination with the sonic, therefore lacking the medium induction reading necessary to use the Induction Tornado Chart for correcting the deep induction reading to an Rt value.

CONCLUSIONS

Eastern View Group Formation (1775-3000)

This formation appears to be comprised of three lithologic zones exhibiting slightly different tool responses. The upper zone (Zone 1) extends from 1775-2145 meters and had a uniformly lower resistivity response than the adjacent middle zone (Zone 2) from 2145-2565 meters. The lower zone (Zone 3) ranged from 2565-3000 meters and exhibited less porosity than Zone 2.

All three zones in this formation were comprised of sand, shale and coal. In addition, both igneous intrusive and volcanic rocks were found in Zone 3 (Figures 3 & 4). The anomalous data points on the crossplots for these intervals were correlated with the cuttings descriptions at those depths for lithologic identification.

The coal beds first appear in the upper half of Zone 3 (Figure 5) above 2740 meters. The bedding becomes very frequent in Zone 2 above 2300 meters (see Figure 6) with numerous thin beds identified on the CPI (Computer Processed Interpretation). The bedding frequency of the coals drops off dramatically in Zone 1 (Figure 7).

There are valid hydrocarbon indications on the CPI (Computer Processed Interpretation) in this formation in the interval from 1810-1860 meters and from 2715-3000 meters (see attached CPI). The shows in the upper interval generally have water saturations in the 50-60% range with a constant bulk volume of water, indicating that the zone should be hydrocarbon productive with little or no water. From the crossplot and histogram in Figure 8, it appears that a water saturation cutoff as high as 70% could be used and still be within the irreducible water saturation limit. The high water saturation is probably due to a small sand grain size resulting in a correspondingly large surface area. The shows in the lower interval have water saturations in the 30-40% range with a constant bulk volume of water, indicating that this zone should also be hydrocarbon productive with little or no water. The lower average water saturation (see Figure 9) is probably due to a correspondingly larger sand grain size than the upper zone.

Hole rugosity, hole caving and borehole washouts accounted for the remainder of the hydrocarbon indications on the CPI. In particular, the interval from 2585-2655 meters appears to be comprised of interbedded volcanics, coals and igneous rocks all of which are badly washed out, causing false hydrocarbon indications. Bed boundary effects on the porosity and resistivity tools caused artificial thin hydrocarbon indications next to many of the coal beds.

dolerite intrusion!

A reservoir sensitivity analysis was computed for both the upper zone (1810-1860 meters) and the lower zone (2715-3000 meters) in the Eastern View Group formation (see Table 1). The porosity was varied from 5-10% in increments of 1%, the shale volume was varied from 35-45% in increments of 5% and the water saturation was varied from 30-60% in increments of 5%. Using a conservative set of cutoffs for the upper zone of 10% minimum porosity with maximum water saturation set to 60% and maximum shale volume set at 40%, the figures indicate that there is 10.5 meters of potential pay with 30.5 meters of net reservoir rock out of a gross interval of 50.25 meters. The average porosity was 25.3% for the pay interval and 23.6% for the potential reservoir rock. The lower zone can best be analyzed using cutoffs of 10% minimum porosity with maximum water saturation set to 40% and maximum shale volume set at 40%. These figures indicate that there is 25.75 meters of potential pay with 47.75 meters of net reservoir rock out of a gross interval of 285.25 meters. The average porosity was 17.4% for the pay interval and 15.3% for the potential reservoir rock.

ANALYSIS TECHNIQUE & INTERPRETATION

All of the logs for this well were environmentally corrected according to the published Schlumberger chart book corrections. No Tornado Chart corrections were applied to the resistivity suite because the rugose hole resulted in very poor MSFL data and the ISF-BHC (Induction-Sonic) tool combination precluded the recording of a medium induction curve.

which was why EPT was run.

Neutron/density and sonic/density crossplots were used to identify the shale parameters for all three zones (Figures 10-12). For Zone 1 (1775-2145 meters) the Gamma Ray and the neutron/density crossplot were used to define the shale volume (see parameter list in Table 2). The caliper curve was used to discriminate bad hole intervals and prevent the erroneous use of the neutron/density crossplot information at those levels. For Zone 2 (2145-2565 meters) the Gamma Ray and the neutron/density crossplot were again used to define the shale volume (see parameter list in Table 3). The caliper curve was used to discriminate the bad hole intervals and prevent the erroneous use of the neutron/density crossplot information at those levels. For Zone 3 (2565-3000 meters) only the Gamma Ray was used to define the shale volume (see parameter list in Table 4). The high quality of the correlation of the Gamma Ray tool with apparent shale volume variations in this zone combined with the severe borehole rugosity and washout problems encountered in the interpretation of the neutron and density data made it the logical choice for the determination of the shale volume.

A Pickett Plot of Rt (true formation resistivity) versus neutron/density crossplot porosity yielded an Rwf (connate water resistivity) of .045 at formation temperature for Zone 1 (Figure 13). A bound water value (Rwb) of .15 at formation temperature was determined for this zone from an RWA/Porosity crossplot (Figure 13). A Pickett plot was also used for Zone 2 to determine the connate water resistivity, which was found to be .087 at formation temperature. The RWA/Porosity plot yielded a bound water resistivity of .13 at formation temperature (Figure 14). Similarly, a Pickett plot and an RWA/Porosity plot were run for Zone 3 (Figure 15) resulting in a connate water resistivity of .076 at formation temperature and a bound water resistivity of .12 at formation temperature. These variations in the connate water salinity, when taken in conjunction with the variations in the frequency and thickness of the coal beds may prove to be depositionally significant.

All of the parameters used in the calculation of the three zones in this well appear in Tables 5-7. Due to the poor borehole condition in this well, the invaded zone water saturation (Sxo) was **not** calculated from the Rxo (shallow invaded zone - usually read by the MSFL tool) tool readings and the sonic **was** used for bad hole porosity control wherever such conditions were determined from the caliper measurement.

Technique

A Dual Water Model was used to compute effective and total porosities, water saturations and a volumetric breakdown of the main constituents of the rock (wet clay, dry clay, silt and matrix volumes). The matrix density for the formation was entered and the program calculated the neutron and density porosities using a sandstone/limestone/dolomite model. The neutron and density porosities were then corrected for clay and hydrocarbon effects. An iterative technique was used to do the hydrocarbon corrections based upon the hydrocarbon density. If at the end of the iteration the hydrocarbon and clay corrected porosities for the neutron and density were not equal, then the program automatically adjusted input parameters to resolve the discrepancy. The adjustments were performed in the following order:

1) The input matrix density was adjusted. This option was allowed for this analysis.

2) The input clay volume was not adjusted.

3) If the previous adjustments did not resolve the discrepancy, the neutron or density input values were considered in error and one or the other was reduced until the discrepancy was resolved.

Between each of the aforementioned adjustments a complete set of hydrocarbon iterations was performed.

The following equations were used in the Dual Water Model analysis:

Matrix corrected neutron porosity:

$$\mathrm{PNC} = \mathrm{PHIN} + (\mathrm{PNS} - \mathrm{PHIN})(2.71 - \mathrm{RHOMA})/.06$$

where: PHIN = Input limestone neutron porosity
PNS = Neutron sandstone porosity

Matrix corrected neutron wet clay porosity:

$$\mathrm{PNWCC} = \mathrm{PNWC} + (\mathrm{PNSWC} - \mathrm{PNWC})(2.71 - \mathrm{RHOMA})/.06$$

where: PNWC = Input limestone neutron porosity for wet clay
PNSWC = Neutron sandstone porosity for wet clay

Density calculations:

$$\mathrm{PDC} = (\mathrm{RHOMA} - \mathrm{RHOB})/(\mathrm{RHOMA} - \mathrm{RHOMF})$$

$$\mathrm{PDDC} = (\mathrm{RHOMA} - \mathrm{RHODC})/(\mathrm{RHOMA} - \mathrm{RHOMF})$$

$$\mathrm{PDWC} = (\mathrm{RHOMA} - \mathrm{RHOWC})/(\mathrm{RHOMA} - \mathrm{RHOMF})$$

where: RHOB = Input curve density
RHODC = Dry clay density
RHOWC = Wet clay density

Neutron porosity for dry clay:

$$\mathrm{PNDCC} = 1 - (1 - \mathrm{PDDC})(1 - \mathrm{PNWCC})/(1 - \mathrm{PDWC})$$

where: PNWCC = Wet clay neutron porosity

Density and neutron clay corrections:

$$\mathrm{PDCR} = \mathrm{PDC} - \mathrm{VCL} * \mathrm{PDWC}$$

$$\mathrm{PNCR} = \mathrm{PNC} - \mathrm{VCL} * \mathrm{PNWCC}$$

where: VCL = Volume of clay

Wet clay point computation of total porosity and dry clay volume:

$$PTOTWC = (PDWC - PDDC)/(1 - PDDC)$$

$$VDCWCP = 1 - PTOTWC$$

Neutron Excavation Factor:

$$PHIX = PHIE + VCL * PNWCC$$

$$SWH = (PHIE(1 - SHR + SHR * PNH) + VCL * PNWCC)/PHIX$$

$$PNEX = (RHOMA/2.66)^2(2*SWH*PHIX^2 + .04*PHIX)(1 - SWH)$$

where: SHR = Residual hydrocarbon saturation

Hydrocarbon corrected neutron and density porosity:

$$PNHC = (PNC + PNEX - VCL*PNWCC*B*SHR)/(1 - B*SHR)$$

$$PDHC = (RHOMA-RHOC+VCL*PDWC*A*SHR)/(RHOMA-RHOMF+A*SHR)$$

where: B = Neutron residual hydrocarbon factor
A = Density residual hydrocarbon factor

Total porosity:

$$PHIT = (PDHC * PNDCC - PNHC * PDDC)/(PNDCC - PDDC)$$

Dry clay volume and bound water saturation:

$$VDC = VCL * VDCWCP$$

$$SWB = (VDC * PTOTWC)/(VDCWCP * PHIT)$$

Effective porosity:

$$PHIE = PHIT(1 - SWB)$$

Water and hydrocarbon saturation:

$$SWT = \left[\frac{Rt*PHIT^m}{a} \left(\frac{1}{RwF} + \frac{SWB}{SWT} \left(\frac{1}{RwB} - \frac{1}{RwF} \right) \right) \right]^{-1/n}$$

$$SXOT = \left[\frac{RXO*PHIT^m}{a} \left(\frac{1}{RmfF} + \frac{SWB}{SXOT} \left(\frac{1}{RmfB} - \frac{1}{RmfF} \right) \right) \right]^{-1/n}$$

SW = (SWT - SWB)/(1 - SWB)

SXO = (SXOT - SWB)/(1 - SWB)

SHR = 1 - SXO

Volumetric calculations:

BVW = PHIE * SW

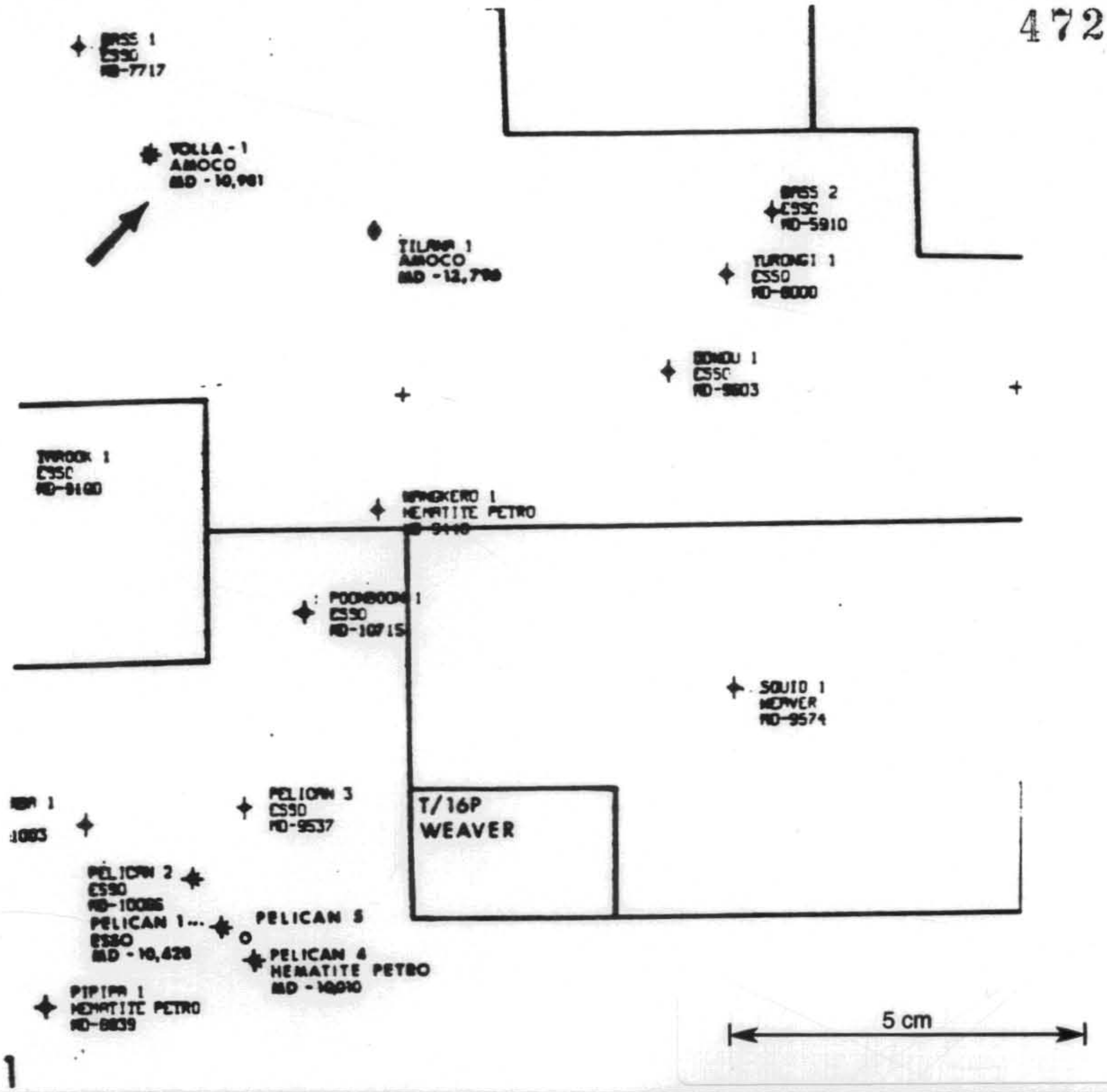
BVWSXO = PHIE * SXO

VWCLAY = VCD + SWB * PHIT

VMATRIX = PHIE(1 - PHIMAX)/PHIMAX

VSILT = 1 - PHIT -VDC -VMATRIX

The computer processed interpretation for this well is attached to this report. In addition, a detailed reservoir sensitivity summary report using appropriate porosity, shale and water saturation cutoffs is included as Table 1.


BASS 1
ESSO
MD-7717
VOLLA-1
AMOCO
MD - 10,981
TILANA 1
AMOCO
MD - 12,790
BASS 2
ESSO
MD-5910
YURONGI 1
ESSO
MD-8000
BONDU 1
ESSO
MD-9803
TARROOK 1
ESSO
MD-9100
WANGKERO 1
HEMATITE PETRO
MD-9440
POONBOON 1
ESSO
MD-10715
SQUID 1
WEAVER
MD-9574
BA 1
1003
PELICAN 3
ESSO
MD-9537
T/16P
WEAVER
PELICAN 2
ESSO
MD-10086
PELICAN 1
ESSO
MD - 10,420
PELICAN 5
PELICAN 4
HEMATITE PETRO
MD - 10010
PIPIPA 1
HEMATITE PETRO
MD-8839
5 cm
1

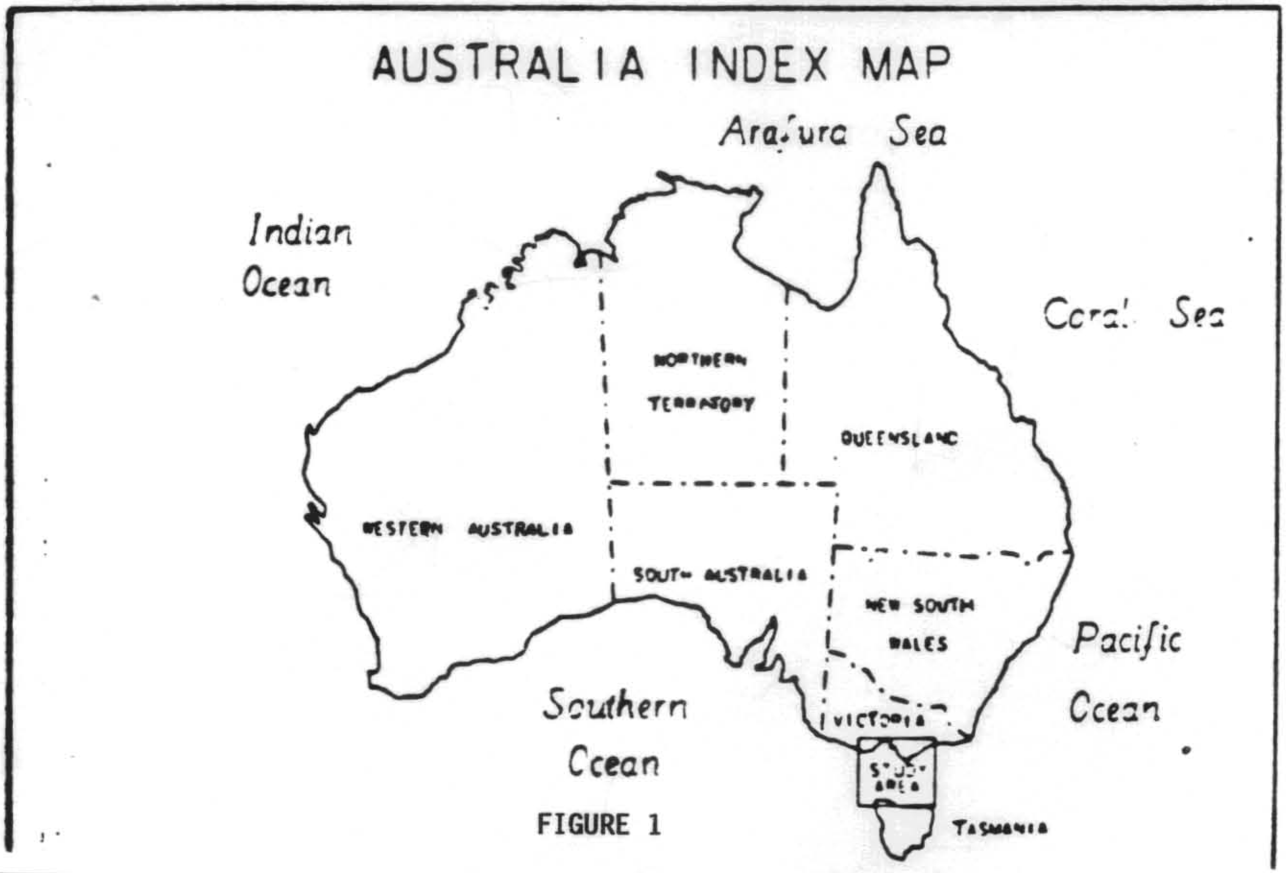

AUSTRALIA INDEX MAP
Arafura Sea
Indian Ocean
Coral Sea
NORTHERN TERRITORY
QUEENSLAND
WESTERN AUSTRALIA
SOUTH AUSTRALIA
NEW SOUTH WALES
VICTORIA
STUDY AREA
TASMANIA
Pacific Ocean
Southern Ocean

FIGURE 1

BASS BASIN
GENERALIZED STRATIGRAPHY

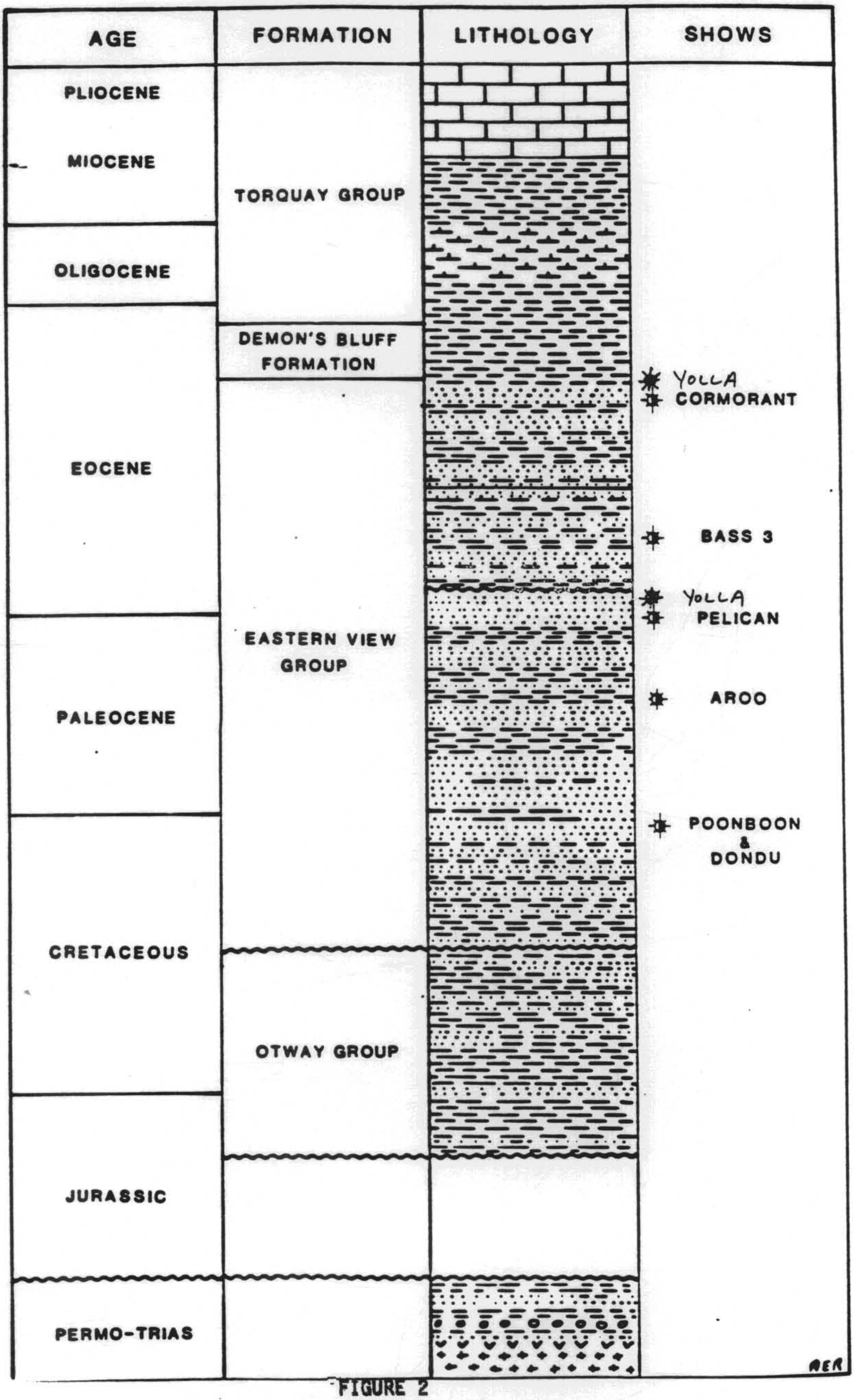
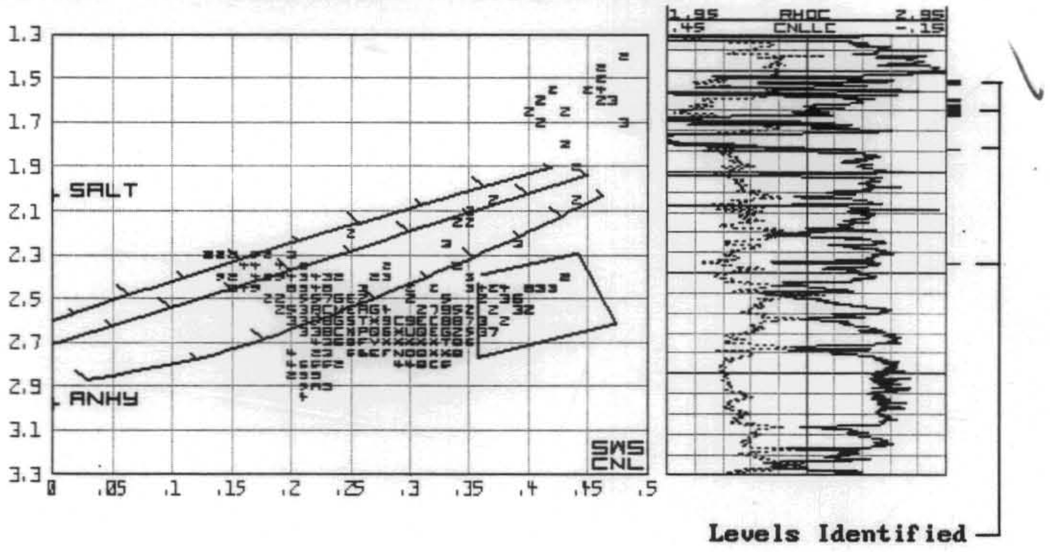


FIGURE 2

IDENTIFICATION OF IGNEOUS ROCK INTERVALS

ZONE 3

ZONE : From 2565.00 to 3000.00 M
X: CNLLC DEC Y: RHOC GM/CC Z: GRC API UNIT
Z scale: 0 33.33366.666100 133.33166.66200



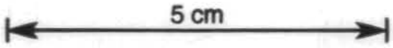


FIGURE 3

IDENTIFICATION OF VOLCANIC INTERVALS

ZONE 3

ZONE : From 2565.00 to 3000.00 M
X: CNLLC DEC Y: RHOC GM/CC Z: GRC API UNIT
Z scale: 0 33.33366.666100 133.33166.66200

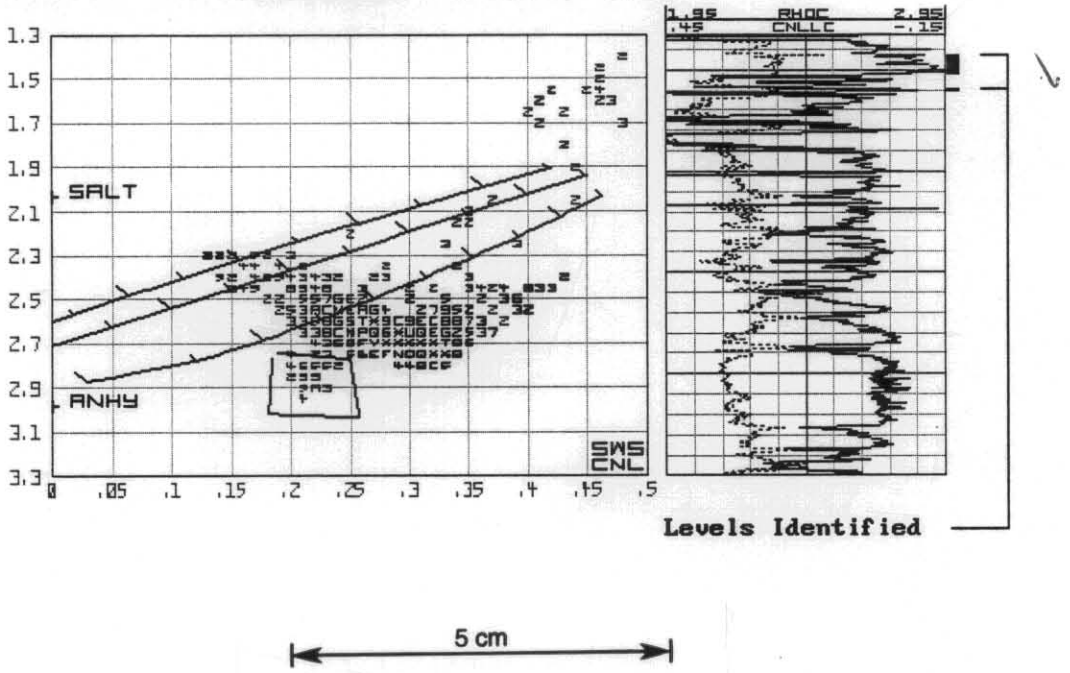


FIGURE 4

COAL BED IDENTIFICATION

ZONE 3

```
ZONE : From  2565.00 to  3000.00 M
X: CNLLC     DEC      Y: RHOC      GM/CC   Z: GRC       API UNIT
Z scale: 0       33.33366.666100    133.33166.66200
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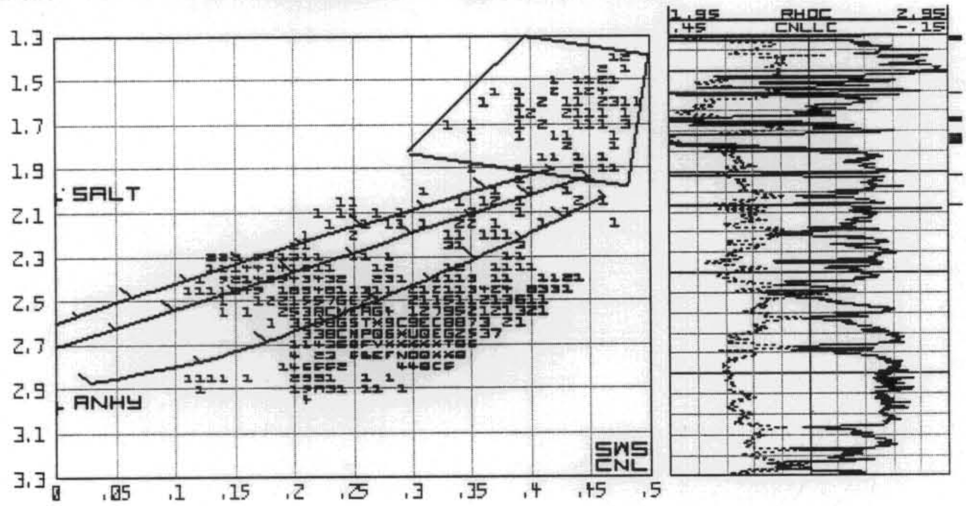


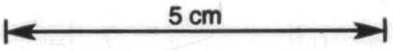
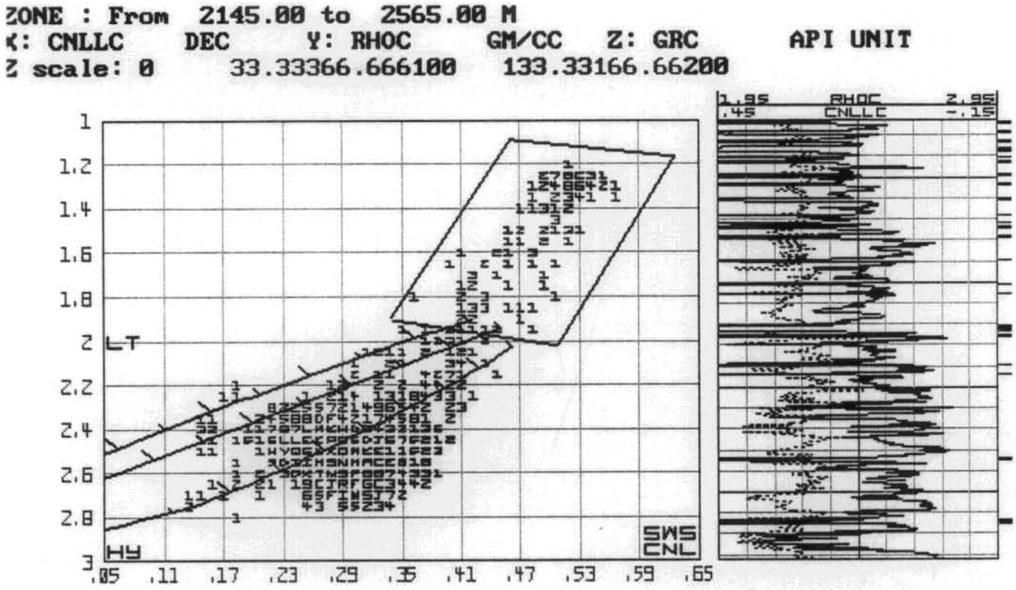


FIGURE 5

COAL BED IDENTIFICATION

ZONE 2



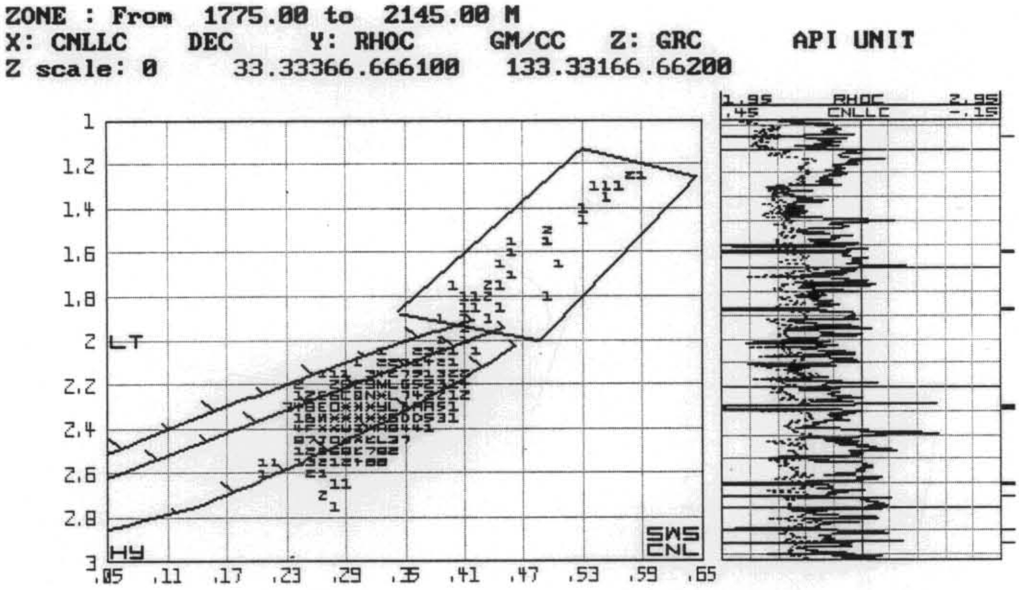
```
ZONE : From  2145.00 to  2565.00 M
X: CNLLC     DEC     Y: RHOC     GM/CC    Z: GRC       API UNIT
Z scale: 0      33.33366.666100    133.33166.66200
```

5 cm

FIGURE 6

COAL BED IDENTIFICATION

ZONE 1



```
ZONE : From  1775.00 to  2145.00 M
X: CNLLC     DEC      Y: RHOC      GM/CC    Z: GRC       API UNIT
Z scale: 0      33.33366.666100   133.33166.66200
```

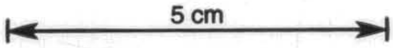
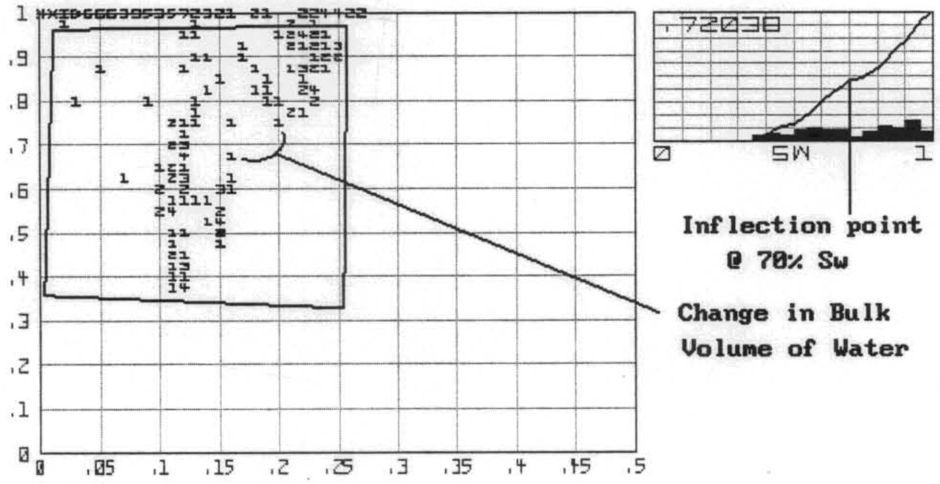


FIGURE 7

WATER SATURATION PARAMETER SELECTION

ZONE 1

ZONE : From 1775.00 to 1875.00 M
X: BVW Y: SW Z: VCL DECIMAL
Z scale: 0 .16667.33333.5 .66667.833331



Inflection point
@ 70% Sw

Change in Bulk
Volume of Water

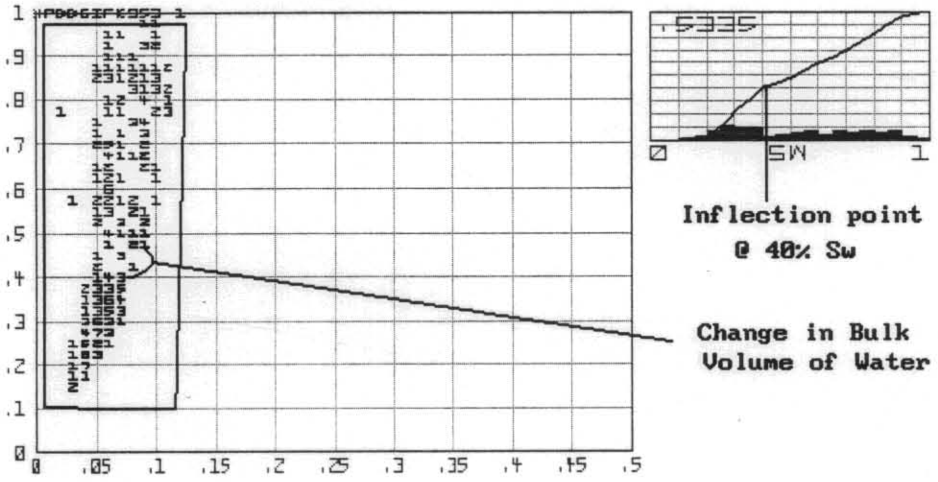
5 cm

FIGURE 8

WATER SATURATION PARAMETER SELECTION

ZONE 3

ZONE : From 2715.00 to 3000.00 M
X: BVW Y: SW Z: VCL DECIMAL
Z scale: 0 .16667.33333.5 .66667.833331



Inflection point
@ 40% Sw

Change in Bulk
Volume of Water

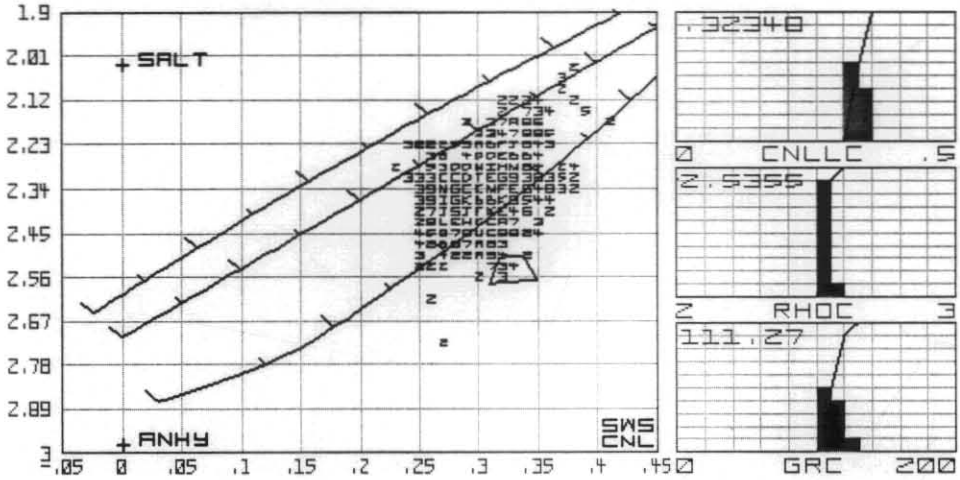
5 cm

FIGURE 9

NEUTRON/DENSITY & SONIC/DENSITY CROSSPLOTS

ZONE 1

ZONE : From 1775.00 to 2145.00 M
X: CNLLC DEC Y: RHOC GM/CC Z: GRC API UNIT
Z scale: 0 33.33366.666100 133.33166.66200



ZONE : From 1775.00 to 2145.00 M
X: DTAFF MS/F Y: RHOC GM/CC Z: GRC API UNIT
Z scale: 0 33.33366.666100 133.33166.66200

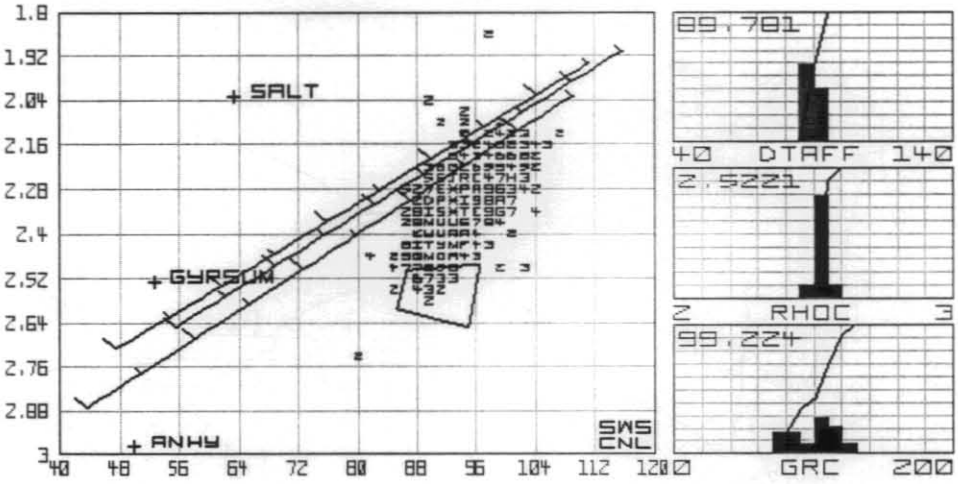


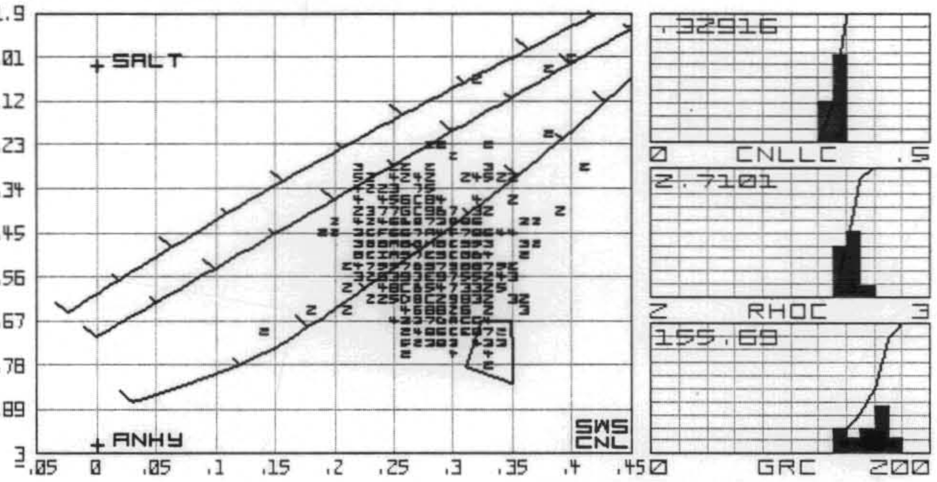
FIGURE 10

5 cm

NEUTRON/DENSITY & SONIC/DENSITY CROSSPLOTS

ZONE 2

```
ZONE : From  2145.00 to  2565.00 M
X: CNLLC     DEC     Y: RHOC     GM/CC    Z: GRC      API UNIT
Z scale: 0       33.33366.666100    133.33166.66200
```



```
ZONE : From  2145.00 to  2565.00 M
X: DTAFF     MS/F    Y: RHOC     GM/CC    Z: GRC      API UNIT
Z scale: 0       33.33366.666100    133.33166.66200
```

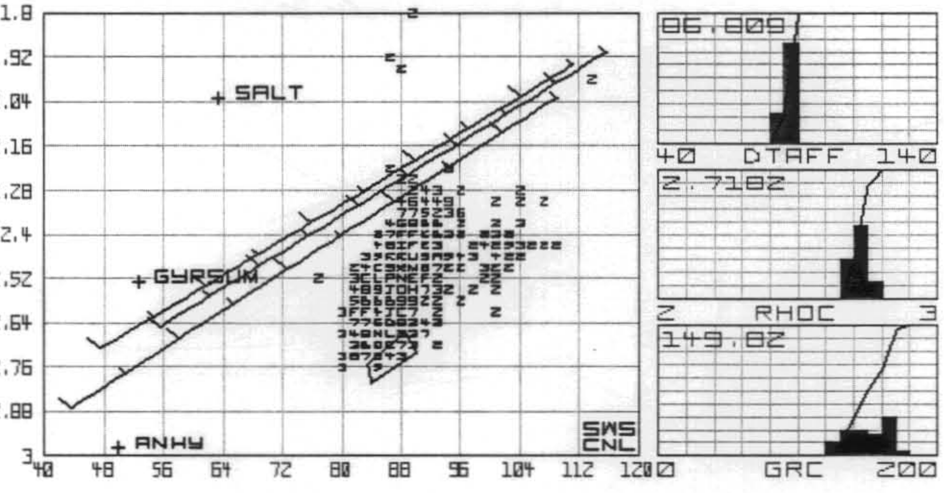


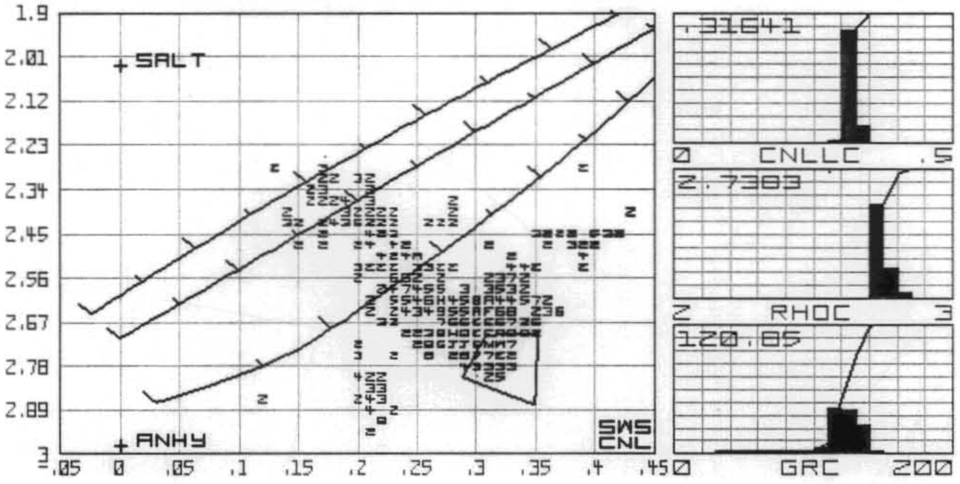
FIGURE 11

5 cm

NEUTRON/DENSITY & SONIC/DENSITY CROSSPLOTS

ZONE 3

ZONE : From 2565.00 to 3000.00 M
X: CNLLC DEC Y: RHOC GM/CC Z: GRC API UNIT
Z scale: 0 33.33366.666100 133.33166.66200



ZONE : From 2565.00 to 3000.00 M
X: DTAFF MS/F Y: RHOC GM/CC Z: GRC API UNIT
Z scale: 0 33.33366.666100 133.33166.66200

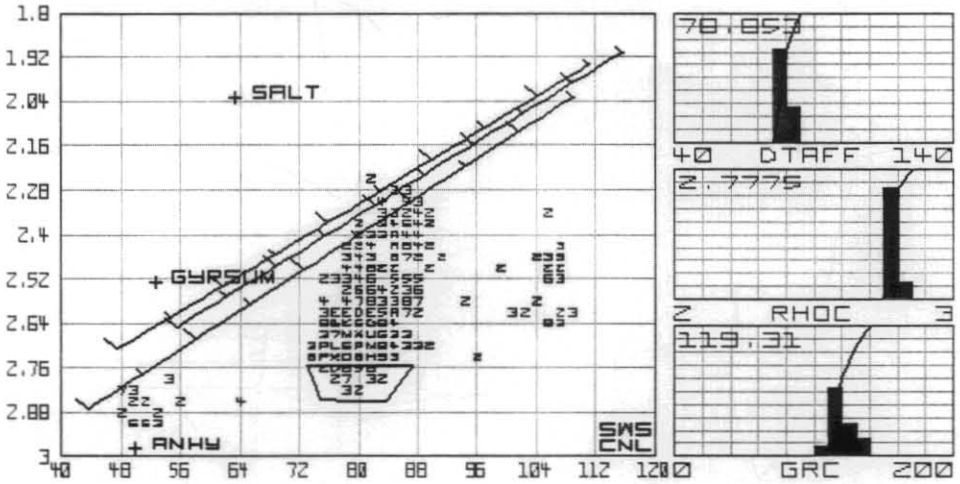
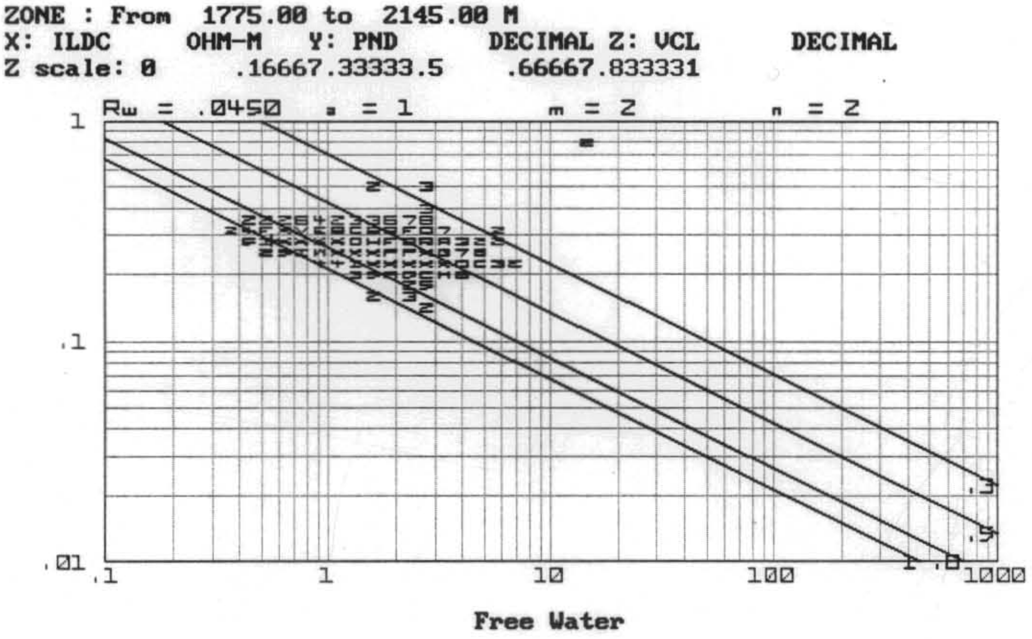


FIGURE 12

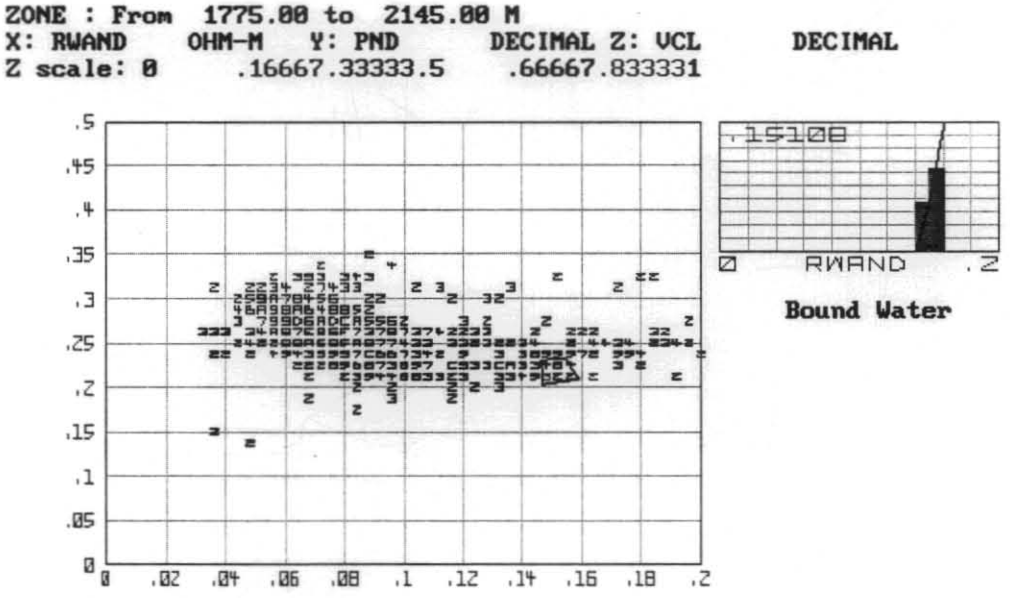
5 cm

FREE WATER PICKETT PLOT & BOUND WATER PLOT

ZONE 1



ZONE : From 1775.00 to 2145.00 M
X: ILDC OHM-M Y: PND DECIMAL Z: VCL DECIMAL
Z scale: 0 .16667.33333.5 .66667.833331



ZONE : From 1775.00 to 2145.00 M
X: RWAND OHM-M Y: PND DECIMAL Z: VCL DECIMAL
Z scale: 0 .16667.33333.5 .66667.833331

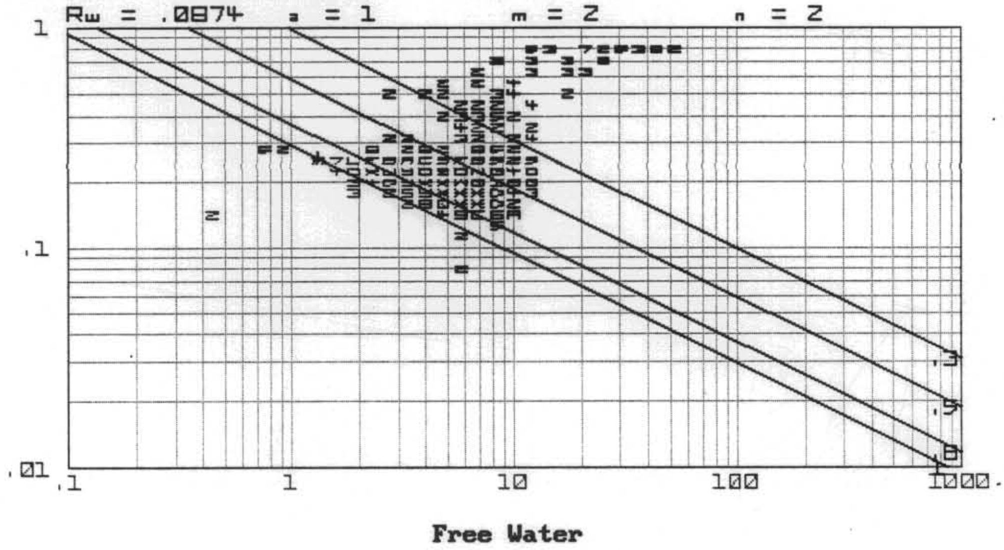
FIGURE 13

5 cm

FREE WATER PICKETT PLOT & BOUND WATER PLOT

ZONE 2

ZONE : From 2145.00 to 2565.00 M
X: ILDC OHM-M Y: PND DECIMAL Z: VCL DECIMAL
Z scale: 0 .16667.33333.5 .66667.833331



ZONE : From 2145.00 to 2565.00 M
X: RWAND OHM-M Y: PND DECIMAL Z: VCL DECIMAL
Z scale: 0 .16667.33333.5 .66667.833331

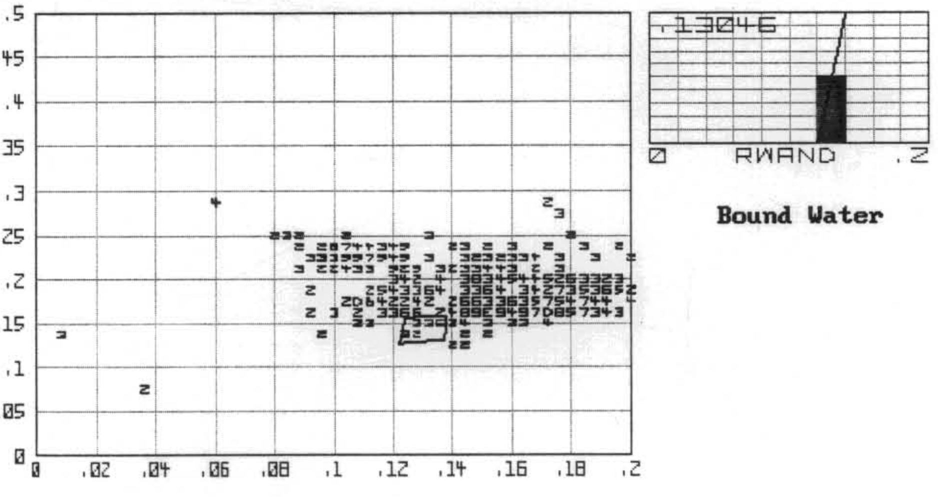


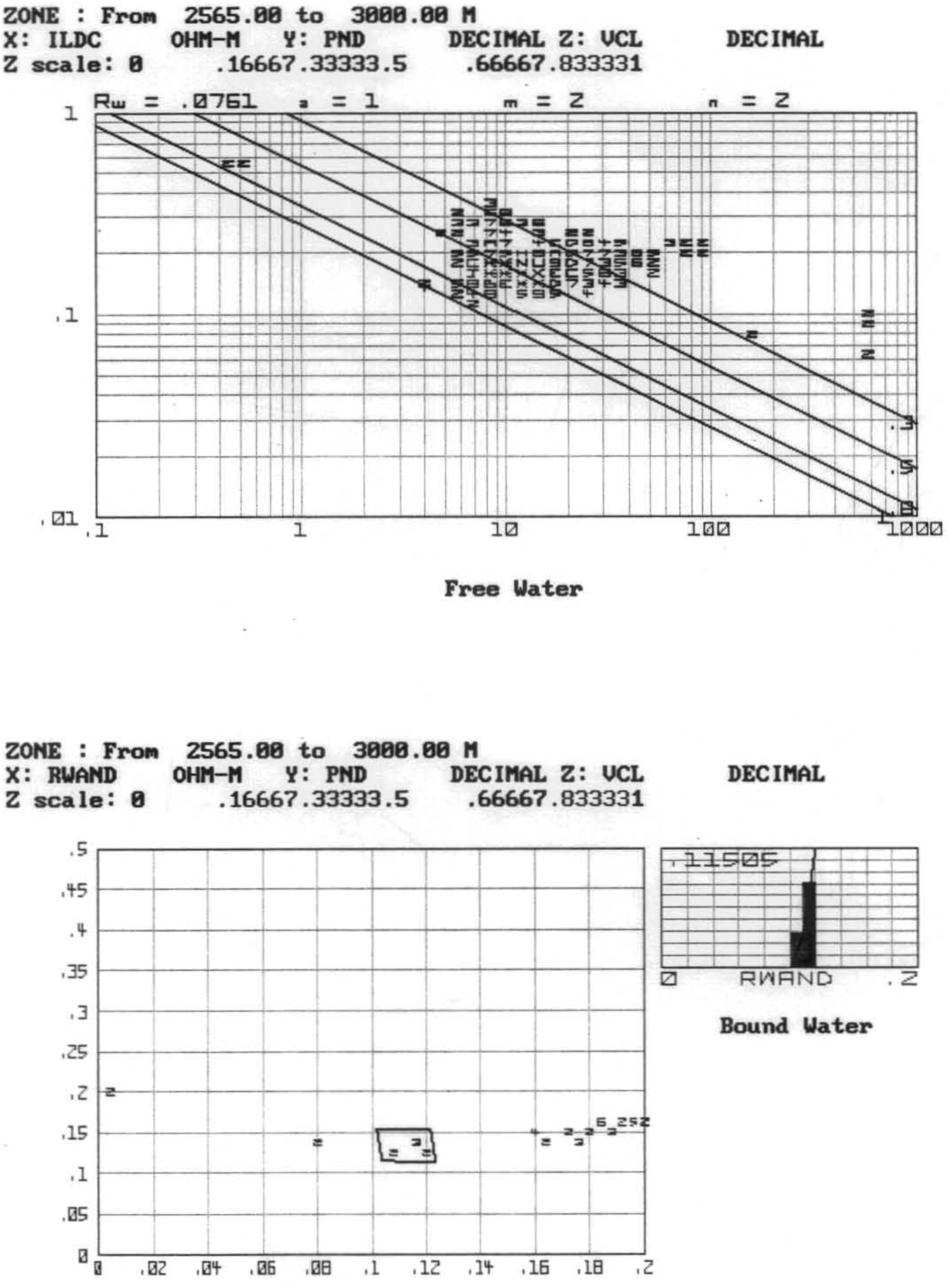
FIGURE 14

5 cm

472125

FREE WATER PICKETT PLOT & BOUND WATER PLOT

ZONE 3



```
ZONE : From  2565.00 to  3000.00 M
X: ILDC      OHM-M   Y: PND        DECIMAL Z: VCL       DECIMAL
Z scale: 0        .16667.33333.5     .66667.833331
```

```
ZONE : From  2565.00 to  3000.00 M
X: RWAND     OHM-M   Y: PND        DECIMAL Z: VCL       DECIMAL
Z scale: 0        .16667.33333.5     .66667.833331
```

FIGURE 15

5 cm

472126

COMPANY : AMOCO AUSTRALIA PETROLEUM COMPANY

WELL : YOLLA #1

FIELD : WILDCAT

COUNTY : BASS STRAIT OFFS

STATE : TASMANIA

COUNTRY : AUSTRALIA

11-AUG-89 @ 08:34:49

TABLE 1

TABLE 1 (Continued)

ZONE : ZONE 1
BASE : 1810.00 M
TOP : 1860.00 M
GROSS : 50.25 M

	CUTOFFS		NET			AVG	AVG	NET RES	AVG
PHI	VCL	Sw	PAY	PHIH	HPVH	PHI	Sw	ROCK	PHI
.050	.350	.300	.00	.00	.00	.000	1.000	22.50	.252
.050	.350	.350	.00	.00	.00	.000	1.000	22.50	.252
.050	.350	.400	1.25	.38	.24	.306	.380	22.50	.252
.050	.350	.450	3.25	.94	.56	.289	.407	22.50	.252
.050	.350	.500	4.50	1.29	.74	.286	.428	22.50	.252
.050	.350	.550	7.00	1.90	1.03	.272	.461	22.50	.252
.050	.350	.600	10.00	2.55	1.30	.255	.491	22.50	.252
.050	.400	.300	.00	.00	.00	.000	1.000	30.50	.236
.050	.400	.350	.00	.00	.00	.000	1.000	30.50	.236
.050	.400	.400	1.25	.38	.24	.306	.380	30.50	.236
.050	.400	.450	3.25	.94	.56	.289	.407	30.50	.236
.050	.400	.500	4.50	1.29	.74	.286	.428	30.50	.236
.050	.400	.550	7.25	1.96	1.05	.271	.462	30.50	.236
.050	.400	.600	10.50	2.66	1.35	.253	.492	30.50	.236
.050	.450	.300	.00	.00	.00	.000	1.000	37.50	.219
.050	.450	.350	.00	.00	.00	.000	1.000	37.50	.219
.050	.450	.400	1.25	.38	.24	.306	.380	37.50	.219
.050	.450	.450	3.25	.94	.56	.289	.407	37.50	.219
.050	.450	.500	4.50	1.29	.74	.286	.428	37.50	.219
.050	.450	.550	7.25	1.96	1.05	.271	.462	37.50	.219
.050	.450	.600	10.50	2.66	1.35	.253	.492	37.50	.219
.060	.350	.300	.00	.00	.00	.000	1.000	22.50	.252
.060	.350	.350	.00	.00	.00	.000	1.000	22.50	.252
.060	.350	.400	1.25	.38	.24	.306	.380	22.50	.252
.060	.350	.450	3.25	.94	.56	.289	.407	22.50	.252
.060	.350	.500	4.50	1.29	.74	.286	.428	22.50	.252
.060	.350	.550	7.00	1.90	1.03	.272	.461	22.50	.252
.060	.350	.600	10.00	2.55	1.30	.255	.491	22.50	.252
.060	.400	.300	.00	.00	.00	.000	1.000	30.50	.236
.060	.400	.350	.00	.00	.00	.000	1.000	30.50	.236
.060	.400	.400	1.25	.38	.24	.306	.380	30.50	.236
.060	.400	.450	3.25	.94	.56	.289	.407	30.50	.236
.060	.400	.500	4.50	1.29	.74	.286	.428	30.50	.236
.060	.400	.550	7.25	1.96	1.05	.271	.462	30.50	.236
.060	.400	.600	10.50	2.66	1.35	.253	.492	30.50	.236
.060	.450	.300	.00	.00	.00	.000	1.000	37.50	.219
.060	.450	.350	.00	.00	.00	.000	1.000	37.50	.219
.060	.450	.400	1.25	.38	.24	.306	.380	37.50	.219
.060	.450	.450	3.25	.94	.56	.289	.407	37.50	.219
.060	.450	.500	4.50	1.29	.74	.286	.428	37.50	.219
.060	.450	.550	7.25	1.96	1.05	.271	.462	37.50	.219
.060	.450	.600	10.50	2.66	1.35	.253	.492	37.50	.219
.070	.350	.300	.00	.00	.00	.000	1.000	22.50	.252
.070	.350	.350	.00	.00	.00	.000	1.000	22.50	.252
.070	.350	.400	1.25	.38	.24	.306	.380	22.50	.252
.070	.350	.450	3.25	.94	.56	.289	.407	22.50	.252
.070	.350	.500	4.50	1.29	.74	.286	.428	22.50	.252
.070	.350	.550	7.00	1.90	1.03	.272	.461	22.50	.252
.070	.350	.600	10.00	2.55	1.30	.255	.491	22.50	.252
.070	.400	.300	.00	.00	.00	.000	1.000	30.50	.236

TABLE 1 (Continued)

ZONE : ZONE 1
BASE : 1810.00 M
TOP : 1860.00 M
GROSS : 50.25 M

	CUTOFFS		NET			AVG	AVG	NET RES	AVG
PHI	VCL	Sw	PAY	PHIH	HPVH	PHI	Sw	ROCK	PHI
.070	.400	.350	.00	.00	.00	.000	1.000	30.50	.236
.070	.400	.400	1.25	.38	.24	.306	.380	30.50	.236
.070	.400	.450	3.25	.94	.56	.289	.407	30.50	.236
.070	.400	.500	4.50	1.29	.74	.286	.428	30.50	.236
.070	.400	.550	7.25	1.96	1.05	.271	.462	30.50	.236
.070	.400	.600	10.50	2.66	1.35	.253	.492	30.50	.236
.070	.450	.300	.00	.00	.00	.000	1.000	37.50	.219
.070	.450	.350	.00	.00	.00	.000	1.000	37.50	.219
.070	.450	.400	1.25	.38	.24	.306	.380	37.50	.219
.070	.450	.450	3.25	.94	.56	.289	.407	37.50	.219
.070	.450	.500	4.50	1.29	.74	.286	.428	37.50	.219
.070	.450	.550	7.25	1.96	1.05	.271	.462	37.50	.219
.070	.450	.600	10.50	2.66	1.35	.253	.492	37.50	.219
.080	.350	.300	.00	.00	.00	.000	1.000	22.50	.252
.080	.350	.350	.00	.00	.00	.000	1.000	22.50	.252
.080	.350	.400	1.25	.38	.24	.306	.380	22.50	.252
.080	.350	.450	3.25	.94	.56	.289	.407	22.50	.252
.080	.350	.500	4.50	1.29	.74	.286	.428	22.50	.252
.080	.350	.550	7.00	1.90	1.03	.272	.461	22.50	.252
.080	.350	.600	10.00	2.55	1.30	.255	.491	22.50	.252
.080	.400	.300	.00	.00	.00	.000	1.000	30.50	.236
.080	.400	.350	.00	.00	.00	.000	1.000	30.50	.236
.080	.400	.400	1.25	.38	.24	.306	.380	30.50	.236
.080	.400	.450	3.25	.94	.56	.289	.407	30.50	.236
.080	.400	.500	4.50	1.29	.74	.286	.428	30.50	.236
.080	.400	.550	7.25	1.96	1.05	.271	.462	30.50	.236
.080	.400	.600	10.50	2.66	1.35	.253	.492	30.50	.236
.080	.450	.300	.00	.00	.00	.000	1.000	37.50	.219
.080	.450	.350	.00	.00	.00	.000	1.000	37.50	.219
.080	.450	.400	1.25	.38	.24	.306	.380	37.50	.219
.080	.450	.450	3.25	.94	.56	.289	.407	37.50	.219
.080	.450	.500	4.50	1.29	.74	.286	.428	37.50	.219
.080	.450	.550	7.25	1.96	1.05	.271	.462	37.50	.219
.080	.450	.600	10.50	2.66	1.35	.253	.492	37.50	.219
.090	.350	.300	.00	.00	.00	.000	1.000	22.50	.252
.090	.350	.350	.00	.00	.00	.000	1.000	22.50	.252
.090	.350	.400	1.25	.38	.24	.306	.380	22.50	.252
.090	.350	.450	3.25	.94	.56	.289	.407	22.50	.252
.090	.350	.500	4.50	1.29	.74	.286	.428	22.50	.252
.090	.350	.550	7.00	1.90	1.03	.272	.461	22.50	.252
.090	.350	.600	10.00	2.55	1.30	.255	.491	22.50	.252
.090	.400	.300	.00	.00	.00	.000	1.000	30.50	.236
.090	.400	.350	.00	.00	.00	.000	1.000	30.50	.236
.090	.400	.400	1.25	.38	.24	.306	.380	30.50	.236
.090	.400	.450	3.25	.94	.56	.289	.407	30.50	.236
.090	.400	.500	4.50	1.29	.74	.286	.428	30.50	.236
.090	.400	.550	7.25	1.96	1.05	.271	.462	30.50	.236
.090	.400	.600	10.50	2.66	1.35	.253	.492	30.50	.236
.090	.450	.300	.00	.00	.00	.000	1.000	37.50	.219
.090	.450	.350	.00	.00	.00	.000	1.000	37.50	.219

TABLE 1 (Continued)

ZONE : ZONE 1
BASE : 1810.00 M
TOP : 1860.00 M
GROSS : 50.25 M

	CUTOFFS		NET			AVG	AVG	NET RES	AVG
PHI	VCL	Sw	PAY	PHIH	HPVH	PHI	Sw	ROCK	PHI
.090	.450	.400	1.25	.38	.24	.306	.380	37.50	.219
.090	.450	.450	3.25	.94	.56	.289	.407	37.50	.219
.090	.450	.500	4.50	1.29	.74	.286	.428	37.50	.219
.090	.450	.550	7.25	1.96	1.05	.271	.462	37.50	.219
.090	.450	.600	10.50	2.66	1.35	.253	.492	37.50	.219
.100	.350	.300	.00	.00	.00	.000	1.000	22.50	.252
.100	.350	.350	.00	.00	.00	.000	1.000	22.50	.252
.100	.350	.400	1.25	.38	.24	.306	.380	22.50	.252
.100	.350	.450	3.25	.94	.56	.289	.407	22.50	.252
.100	.350	.500	4.50	1.29	.74	.286	.428	22.50	.252
.100	.350	.550	7.00	1.90	1.03	.272	.461	22.50	.252
.100	.350	.600	10.00	2.55	1.30	.255	.491	22.50	.252
.100	.400	.300	.00	.00	.00	.000	1.000	30.50	.236
.100	.400	.350	.00	.00	.00	.000	1.000	30.50	.236
.100	.400	.400	1.25	.38	.24	.306	.380	30.50	.236
.100	.400	.450	3.25	.94	.56	.289	.407	30.50	.236
.100	.400	.500	4.50	1.29	.74	.286	.428	30.50	.236
.100	.400	.550	7.25	1.96	1.05	.271	.462	30.50	.236
.100	.400	.600	10.50	2.66	1.35	.253	.492	30.50	.236
.100	.450	.300	.00	.00	.00	.000	1.000	37.50	.219
.100	.450	.350	.00	.00	.00	.000	1.000	37.50	.219
.100	.450	.400	1.25	.38	.24	.306	.380	37.50	.219
.100	.450	.450	3.25	.94	.56	.289	.407	37.50	.219
.100	.450	.500	4.50	1.29	.74	.286	.428	37.50	.219
.100	.450	.550	7.25	1.96	1.05	.271	.462	37.50	.219
.100	.450	.600	10.50	2.66	1.35	.253	.492	37.50	.219

TABLE 1 (Continued)

ZONE : ZONE 3
BASE : 2715.00 M
TOP : 3000.00 M
GROSS : 285.25 M

PAGE 1

CUTOFFS PHI	 VCL	 Sw	NET PAY	 PHIH	 HPVH	AVG PHI	AVG Sw	NET RES ROCK	AVG PHI
.050	.350	.300	13.25	2.42	1.83	.182	.244	64.25	.134
.050	.350	.350	19.25	3.46	2.53	.180	.269	64.25	.134
.050	.350	.400	25.25	4.42	3.12	.175	.292	64.25	.134
.050	.350	.450	26.50	4.61	3.24	.174	.298	64.25	.134
.050	.350	.500	29.00	4.97	3.42	.171	.311	64.25	.134
.050	.350	.550	32.25	5.37	3.61	.167	.327	64.25	.134
.050	.350	.600	36.00	5.83	3.81	.162	.347	64.25	.134
.050	.400	.300	13.25	2.42	1.83	.182	.244	70.50	.129
.050	.400	.350	19.50	3.49	2.55	.179	.270	70.50	.129
.050	.400	.400	25.75	4.47	3.16	.174	.293	70.50	.129
.050	.400	.450	27.00	4.67	3.28	.173	.298	70.50	.129
.050	.400	.500	29.75	5.07	3.48	.170	.313	70.50	.129
.050	.400	.550	33.00	5.47	3.67	.166	.328	70.50	.129
.050	.400	.600	37.00	5.95	3.88	.161	.348	70.50	.129
.050	.450	.300	13.25	2.42	1.83	.182	.244	74.50	.127
.050	.450	.350	19.50	3.49	2.55	.179	.270	74.50	.127
.050	.450	.400	25.75	4.47	3.16	.174	.293	74.50	.127
.050	.450	.450	27.25	4.70	3.29	.172	.299	74.50	.127
.050	.450	.500	30.00	5.10	3.50	.170	.313	74.50	.127
.050	.450	.550	33.25	5.50	3.69	.165	.329	74.50	.127
.050	.450	.600	37.25	5.98	3.90	.160	.348	74.50	.127
.060	.350	.300	13.25	2.42	1.83	.182	.244	62.50	.136
.060	.350	.350	19.25	3.46	2.53	.180	.269	62.50	.136
.060	.350	.400	25.25	4.42	3.12	.175	.292	62.50	.136
.060	.350	.450	26.50	4.61	3.24	.174	.298	62.50	.136
.060	.350	.500	29.00	4.97	3.42	.171	.311	62.50	.136
.060	.350	.550	32.25	5.37	3.61	.167	.327	62.50	.136
.060	.350	.600	36.00	5.83	3.81	.162	.347	62.50	.136
.060	.400	.300	13.25	2.42	1.83	.182	.244	68.00	.132
.060	.400	.350	19.50	3.49	2.55	.179	.270	68.00	.132
.060	.400	.400	25.75	4.47	3.16	.174	.293	68.00	.132
.060	.400	.450	27.00	4.67	3.28	.173	.298	68.00	.132
.060	.400	.500	29.75	5.07	3.48	.170	.313	68.00	.132
.060	.400	.550	33.00	5.47	3.67	.166	.328	68.00	.132
.060	.400	.600	37.00	5.95	3.88	.161	.348	68.00	.132
.060	.450	.300	13.25	2.42	1.83	.182	.244	71.50	.130
.060	.450	.350	19.50	3.49	2.55	.179	.270	71.50	.130
.060	.450	.400	25.75	4.47	3.16	.174	.293	71.50	.130
.060	.450	.450	27.25	4.70	3.29	.172	.299	71.50	.130
.060	.450	.500	30.00	5.10	3.50	.170	.313	71.50	.130
.060	.450	.550	33.25	5.50	3.69	.165	.329	71.50	.130
.060	.450	.600	37.25	5.98	3.90	.160	.348	71.50	.130
.070	.350	.300	13.25	2.42	1.83	.182	.244	59.50	.139
.070	.350	.350	19.25	3.46	2.53	.180	.269	59.50	.139
.070	.350	.400	25.25	4.42	3.12	.175	.292	59.50	.139
.070	.350	.450	26.50	4.61	3.24	.174	.298	59.50	.139
.070	.350	.500	29.00	4.97	3.42	.171	.311	59.50	.139
.070	.350	.550	32.25	5.37	3.61	.167	.327	59.50	.139
.070	.350	.600	36.00	5.83	3.81	.162	.347	59.50	.139
.070	.400	.300	13.25	2.42	1.83	.182	.244	64.00	.136

TABLE 1 (Continued)

ZONE : ZONE 3
BASE : 2715.00 M
TOP : 3000.00 M
GROSS : 285.25 M

	CUTOFFS		NET			AVG	AVG	NET RES	AVG
PHI	VCL	Sw	PAY	PHIH	HPVH	PHI	Sw	ROCK	PHI
.070	.400	.350	19.50	3.49	2.55	.179	.270	64.00	.136
.070	.400	.400	25.75	4.47	3.16	.174	.293	64.00	.136
.070	.400	.450	27.00	4.67	3.28	.173	.298	64.00	.136
.070	.400	.500	29.75	5.07	3.48	.170	.313	64.00	.136
.070	.400	.550	33.00	5.47	3.67	.166	.328	64.00	.136
.070	.400	.600	37.00	5.95	3.88	.161	.348	64.00	.136
.070	.450	.300	13.25	2.42	1.83	.182	.244	67.00	.134
.070	.450	.350	19.50	3.49	2.55	.179	.270	67.00	.134
.070	.450	.400	25.75	4.47	3.16	.174	.293	67.00	.134
.070	.450	.450	27.25	4.70	3.29	.172	.299	67.00	.134
.070	.450	.500	30.00	5.10	3.50	.170	.313	67.00	.134
.070	.450	.550	33.25	5.50	3.69	.165	.329	67.00	.134
.070	.450	.600	37.25	5.98	3.90	.160	.348	67.00	.134
.080	.350	.300	13.25	2.42	1.83	.182	.244	55.75	.144
.080	.350	.350	19.25	3.46	2.53	.180	.269	55.75	.144
.080	.350	.400	25.25	4.42	3.12	.175	.292	55.75	.144
.080	.350	.450	26.50	4.61	3.24	.174	.298	55.75	.144
.080	.350	.500	29.00	4.97	3.42	.171	.311	55.75	.144
.080	.350	.550	32.25	5.37	3.61	.167	.327	55.75	.144
.080	.350	.600	36.00	5.83	3.81	.162	.347	55.75	.144
.080	.400	.300	13.25	2.42	1.83	.182	.244	59.00	.141
.080	.400	.350	19.50	3.49	2.55	.179	.270	59.00	.141
.080	.400	.400	25.75	4.47	3.16	.174	.293	59.00	.141
.080	.400	.450	27.00	4.67	3.28	.173	.298	59.00	.141
.080	.400	.500	29.75	5.07	3.48	.170	.313	59.00	.141
.080	.400	.550	33.00	5.47	3.67	.166	.328	59.00	.141
.080	.400	.600	37.00	5.95	3.88	.161	.348	59.00	.141
.080	.450	.300	13.25	2.42	1.83	.182	.244	60.50	.140
.080	.450	.350	19.50	3.49	2.55	.179	.270	60.50	.140
.080	.450	.400	25.75	4.47	3.16	.174	.293	60.50	.140
.080	.450	.450	27.25	4.70	3.29	.172	.299	60.50	.140
.080	.450	.500	30.00	5.10	3.50	.170	.313	60.50	.140
.080	.450	.550	33.25	5.50	3.69	.165	.329	60.50	.140
.080	.450	.600	37.25	5.98	3.90	.160	.348	60.50	.140
.090	.350	.300	13.25	2.42	1.83	.182	.244	53.25	.146
.090	.350	.350	19.25	3.46	2.53	.180	.269	53.25	.146
.090	.350	.400	25.25	4.42	3.12	.175	.292	53.25	.146
.090	.350	.450	26.50	4.61	3.24	.174	.298	53.25	.146
.090	.350	.500	29.00	4.97	3.42	.171	.311	53.25	.146
.090	.350	.550	32.25	5.37	3.61	.167	.327	53.25	.146
.090	.350	.600	36.00	5.83	3.81	.162	.347	53.25	.146
.090	.400	.300	13.25	2.42	1.83	.182	.244	55.75	.145
.090	.400	.350	19.50	3.49	2.55	.179	.270	55.75	.145
.090	.400	.400	25.75	4.47	3.16	.174	.293	55.75	.145
.090	.400	.450	27.00	4.67	3.28	.173	.298	55.75	.145
.090	.400	.500	29.75	5.07	3.48	.170	.313	55.75	.145
.090	.400	.550	33.00	5.47	3.67	.166	.328	55.75	.145
.090	.400	.600	37.00	5.95	3.88	.161	.348	55.75	.145
.090	.450	.300	13.25	2.42	1.83	.182	.244	56.75	.144
.090	.450	.350	19.50	3.49	2.55	.179	.270	56.75	.144

TABLE 1 (Continued)

ZONE : ZONE 3
BASE : 2715.00 M
TOP : 3000.00 M
GROSS : 285.25 M

CUTOFFS PHI	VCL	Sw	NET PAY	PHIH	HPVH	AVG PHI	AVG Sw	NET RES ROCK	AVG PHI
.090	.450	.400	25.75	4.47	3.16	.174	.293	56.75	.144
.090	.450	.450	27.25	4.70	3.29	.172	.299	56.75	.144
.090	.450	.500	30.00	5.10	3.50	.170	.313	56.75	.144
.090	.450	.550	33.25	5.50	3.69	.165	.329	56.75	.144
.090	.450	.600	37.25	5.98	3.90	.160	.348	56.75	.144
.100	.350	.300	13.25	2.42	1.83	.182	.244	46.25	.154
.100	.350	.350	19.25	3.46	2.53	.180	.269	46.25	.154
.100	.350	.400	25.25	4.42	3.12	.175	.292	46.25	.154
.100	.350	.450	26.50	4.61	3.24	.174	.298	46.25	.154
.100	.350	.500	29.00	4.97	3.42	.171	.311	46.25	.154
.100	.350	.550	31.50	5.30	3.58	.168	.325	46.25	.154
.100	.350	.600	33.75	5.61	3.71	.166	.338	46.25	.154
.100	.400	.300	13.25	2.42	1.83	.182	.244	47.75	.153
.100	.400	.350	19.50	3.49	2.55	.179	.270	47.75	.153
.100	.400	.400	25.75	4.47	3.16	.174	.293	47.75	.153
.100	.400	.450	27.00	4.67	3.28	.173	.298	47.75	.153
.100	.400	.500	29.75	5.07	3.48	.170	.313	47.75	.153
.100	.400	.550	32.25	5.40	3.64	.167	.326	47.75	.153
.100	.400	.600	34.50	5.71	3.77	.165	.339	47.75	.153
.100	.450	.300	13.25	2.42	1.83	.182	.244	48.25	.153
.100	.450	.350	19.50	3.49	2.55	.179	.270	48.25	.153
.100	.450	.400	25.75	4.47	3.16	.174	.293	48.25	.153
.100	.450	.450	27.25	4.70	3.29	.172	.299	48.25	.153
.100	.450	.500	30.00	5.10	3.50	.170	.313	48.25	.153
.100	.450	.550	32.50	5.43	3.66	.167	.326	48.25	.153
.100	.450	.600	34.75	5.74	3.79	.165	.339	48.25	.153

```
YOLLA #1
7-AUG-89 @ 08:27:53
ZONE : From  1775.00 to  2145.00


             CLAY VOLUME DETERMINATION

Gamma Ray curve    = GRC      clean   =   22.00 clay    =  111.00
Discriminator1     = CAL      minimum =    8.00 maximum =   15.00

CROSS PLOT curves and parameters given as:
Density curve      = RHOC     clay    =    2.54
Neutron curve      = CNLLC    clay    =     .32
Sonic curve        = DTAFF    clay    =   89.80

LINES option chosen
   Density [at the point where Neutron is zero] =    2.65
   Density [at the point where Neutron is 0.20] =    2.30
```

TABLE 2

```
YOLLA #1
7-AUG-89 @ 08:35:31
ZONE : From  2145.00 to  2565.00


         CLAY VOLUME DETERMINATION

GAMMA RAY curved
Gamma Ray curve    = GRC      clean   =   10.00 clay    =  156.00
Discriminator1     = CAL      minimum =    8.00 maximum =   15.00

CROSS PLOT curves and parameters given as:
Density curve      = RHOC     clay    =    2.71
Neutron curve      = CNLLC    clay    =     .33
Sonic curve        = DTAFF    clay    =   86.80

LINES option chosen
    Density [at the point where Neutron is zero] =    2.65
    Density [at the point where Neutron is 0.20] =    2.30
```

TABLE 3

```
YOLLA #1
7-AUG-89 @ 08:52:13
ZONE : From  2565.00 to  3000.00


         CLAY VOLUME DETERMINATION

GAMMA RAY curved
Gamma Ray curve    = GRC      clean    =   20.00 clay     =  121.00
Discriminator1     = CAL      minimum  =    8.00 maximum  =   15.00

CROSS PLOT curves and parameters given as:
Density curve      = RHOC     clay     =    2.74
Neutron curve      = CNLLC    clay     =     .32

LINES option chosen
```

TABLE 4

```
YOLLA #1
8-AUG-89 @ 08:14:31
ZONE : From  1775.00 to  2145.00

      CONSTANTS used by DUAL WATER ANALYSIS

Input curve names are:
 CNLLC     for NEUTRON
 RHOC      for DENSITY
 DTAFF     for SONIC
 VCL       for VOLUME CLAY
 CLF       for CLAY FLAG
 ILDC      for RT
 T         for TEMPERATURE
  Neutron type was CNL
  Rho matrix was variable
  Hydrocarbon density was variable
  Vclay was fixed to the input value
  Porosity model was standard
  m was variable with vclay
  Coal logic was used
  Discriminator for limit logic was DTAFF
     Discriminator minimum limit =  17.000
     Discriminator maximum limit =  30.000
      ____________________________________________________________

                    User specified parameters

RwF           = .045      RwF Temp      = 176       RmfF          = .838
RmfF Temp     = 61        RwB           = .15       RwB Temp      = 176
RmfB          = .15       RmfB Temp     = 176       MF Density    =
P NaCl        =           HC Density    =           HC Den Min.   = .3
Neu HC Factor=            Den HC Factor=            Phi*Shr Limit=
Matrix Den.   = 2.65      Wet Clay Den = 2.536      Dry Clay Den = 2.8
Neu Wet Clay = .323       Phi Max       = .32       Delta Phi Max=
Delta GD +    = .08       Delta GD -    = .06       a             = 1
m             = 2         n             = 2         Vo Clay Limit= .35
EXP (Sxo-Sw) = .2         IF (SW-Sxo)   = 3         Den Salt      =
Neu Salt      =           Den Coal      = 2.10      Neu Coal      = .35
TP Water      =           TP Clay       =          TP Hydrocarbon=
TP Limestone =            TP Sandstone =            TP Dolomite   =
Min Value m   =           Max Value m   =
Discrim. Min.= 17         Discrim. Max.= 30
           Bad hole logic Sonic parameters
DT Matrix     = 55.6      DT Fluid      = 189       DT Clay       = 89.8
CP            = 1
      ____________________________________________________________


    MF Density    was calculated to be       .996
    P NaCl        was calculated to be       .008

++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++
```

TABLE 5

```
YOLLA #1
8-AUG-89 @ 07:43:42
ZONE : From  2145.00 to  2565.00

      CONSTANTS used by DUAL WATER ANALYSIS

Input curve names are:
 CNLLC     for NEUTRON
 RHOC      for DENSITY
 DTAFF     for SONIC
 VCL       for VOLUME CLAY
 CLF       for CLAY FLAG
 ILDC      for RT
 T         for TEMPERATURE
  Neutron type was CNL
  Rho matrix was variable
  Hydrocarbon density was variable
  Vclay was fixed to the input value
  Porosity model was standard
  m was variable with vclay
  Coal logic was used
  Discriminator for limit logic was DTAFF
     Discriminator minimum limit =  15.000
     Discriminator maximum limit =  30.000
      ____________________________________________________________

                   User specified parameters

RwF            = .087       RwF Temp      = 202        RmfF           = .838
RmfF Temp      = 61         RwB           = .13        RwB Temp       = 202
RmfB           = .13        RmfB Temp     = 202        MF Density     =
P NaCl         =            HC Density    =            HC Den Min.    = .3
Neu HC Factor=              Den HC Factor=             Phi*Shr Limit=
Matrix Den.    = 2.65       Wet Clay Den  = 2.710      Dry Clay Den  = 2.8
Neu Wet Clay   = .329       Phi Max       = .26        Delta Phi Max=
Delta GD +     = .08        Delta GD -    = .06        a              = 1
m              = 2          n             = 2          Vo Clay Limit= .35
EXP (Sxo-Sw)   = .2         IF (SW-Sxo)   = 3          Den Salt       =
Neu Salt       =            Den Coal      = 2.15       Neu Coal       = .35
TP Water       =            TP Clay       =           TP Hydrocarbon=
TP Limestone =              TP Sandstone =             TP Dolomite    =
Min Value m    =            Max Value m   =
Discrim. Min.= 15           Discrim. Max.= 30
                 Bad hole logic Sonic parameters
DT Matrix      = 55.6       DT Fluid      = 189        DT Clay        = 86.8
CP             = 1
      ____________________________________________________________

    MF Density    was calculated to be      .990
    P NaCl        was calculated to be      .008

++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++
```

TABLE 6

```
YOLLA #1
8-AUG-89 @ 07:46:23
ZONE : From  2565.00 to  3000.00

      CONSTANTS used by DUAL WATER ANALYSIS

Input curve names are:
 CNLLC     for NEUTRON
 RHOC      for DENSITY
 DTAFF     for SONIC
 VCL       for VOLUME CLAY
 CLF       for CLAY FLAG
 ILDC      for RT
 T         for TEMPERATURE
  Neutron type was CNL
  Rho matrix was variable
  Hydrocarbon density was variable
  Vclay was fixed to the input value
  Porosity model was standard
  m was variable with vclay
  Coal logic was used
  Discriminator for limit logic was DTAFF
     Discriminator minimum limit =  15.000
     Discriminator maximum limit =  30.000
______________________________________________________________

                 User specified parameters

RwF            = .076        RwF Temp       = 227        RmfF           = .838
RmfF Temp      = 61          RwB            = .115       RwB Temp       = 227
RmfB           = .115        RmfB Temp      = 227        MF Density     =
P NaCl         =             HC Density     =            HC Den Min.    = .3
Neu HC Factor=               Den HC Factor=              Phi*Shr Limit=
Matrix Den.    = 2.65        Wet Clay Den = 2.738        Dry Clay Den = 2.8
Neu Wet Clay = .316          Phi Max        = .24        Delta Phi Max=
Delta GD +     = .08         Delta GD -     = .06        a              = 1
m              = 2           n              = 2          Vo Clay Limit= .35
EXP (Sxo-Sw) = .2            IF (SW-Sxo)    = 3          Den Salt       =
Neu Salt       =             Den Coal       = 2.15       Neu Coal       = .35
TP Water       =             TP Clay        =           TP Hydrocarbon=
TP Limestone =               TP Sandstone =              TP Dolomite    =
Min Value m    =             Max Value m    =
Discrim. Min.= 15            Discrim. Max.= 30
             Bad hole logic Sonic parameters
DT Matrix      = 55.6        DT Fluid       = 189        DT Clay        = 89.8
CP             = 1
______________________________________________________________

    MF Density     was calculated to be       .983
    P NaCl         was calculated to be       .008

++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++++
```

TABLE 7

Enclosure 1.

472139

OR-0363 VOL II

5 cm

Log Analysis by R.L. Terry

COMPANY AMOCO AUSTRALIA PETROLEUM COMPANY
WELL YOLLA #1
FIELD WILDCAT
COUNTY BASS STRAIT OFFSHORE STATE TASMANIA COUNTRY AUSTRALIA
LOCATION LAT 039 50 18.96 S
LONG 145 48 21.20 E
SECTION ______ TOWNSHIP ______ RANGE ______ API NUM 97033037890
Permanent Datum MSL ; Elevation 0.0 Elev.: K.B. 11.0 M
Log Measured From KB ,11.0 Above Perm. Datum D.F. 10.4 M
Drilling Meas From KB G.L. -79.6 M

Run No.	1	2	3
Date	22-AUG-85		
Depth - Driller	3347		
Depth - Logger	3351		
Btm Log Interval	3350		
Top Log Interval	1755		
Casing - Driller	1752		
Casing - Logger	1755		
Bitsize	12.25		
Type Fluid in Hole	FRESH WATER POLYM		
Dens. / Visc.	9.8 / 44	/	/
pH / Fluid Loss	11 / 9	/	/
Source of Sample	FLOWLINE		
Rm @ Meas. Temp	1.07 @ 23 C	@	@
Rmf @ Meas. Temp	.838 @ 16 C	@	@
Rmc @ Meas. Temp	1.37 @ 16 C	@	@
Source: Rmf / Rmc	PRESS / PRESS	/	/
Rm @ BHT	.335 @ 121 C	@	@
Max. Rec. Temp.	121		

REMARKS :

GRC = Environmentally corrected gamma ray
DCAL = Differential caliper (difference between bit size and caliper)
SW = Water saturation
PHIE = Effective porosity (shale effect removed)
BVW = Bulk volume of water

Note: Black indicates possible hydrocarbons; White indicates water in pore space.

YOLLA #1
8-AUG-89 @ 08:43:29

1 / 500 METERS | GRC API UNIT 0 – 200 | DCAL -10 – 10 | SW 1 – 0 | PHIE .5 – 0 | BVW .5 – 0 | CLAY DEC 0 – 1 | SILT DEC 0 – 1 | MATRIX DEC 0 – 1 | PHI DEC 0 – 1 | COAL DEC 0 – 1

1 / 500 METERS | GRC API UNIT 0 – 200 | DCAL -10 – 10 | SW 1 – 0 | PHIE .5 – 0 | BVW .5 – 0 | CLAY DEC 0 – 1 | SILT DEC 0 – 1 | MATRIX DEC 0 – 1 | PHI DEC 0 – 1 | COAL DEC 0 – 1

APPENDIX 2

472140

TPR
OR-363
VOL III/4

DEVELOPMENT STUDY YOLLA GAS FIELD

FOR

AMOCO AUSTRALIA PETROLEUM COMPANY

Prepared by
R.J. Brown - CMPS
Chatswood Plaza, South Tower, Railway Street
Chatswood NSW 2067

July 1989

TPR
OR-363
VOL III/4

2298R

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SUMMARY

This study has shown that the preferred scheme for Yolla is the development of a fixed steel platform producing both gas and liquids transported to shore via a single submarine pipeline. For a 15% internal rate of return (IRR) sales gas can be sold Victoria at $1.84/GJ and in Tasmania for $2.88/GJ.

The initial capital expenditure for gas being sold to Victoria is approximately $250 million and $226 million for gas sold to Tasmania.

1. INTRODUCTION

The purpose of this study has been to determine the selling price for Yolla gas to provide an IRR of 10%, 15% and 20% on capital invested in the development of the Yolla gas field in the Bass Strait, Australia.

The study has looked at the processing requirements of natural gas from Yolla Field to meet markets identified by others. Two separate independent markets exist.

(a) Victoria
(b) Tasmania

The field contains two separate reservoir bodies, identified as the upper and lower reservoirs.

Various options identified in the Scope of Work were considered :

Case 1 To produce from the lower reservoir only and sell gas to either of the 2 markets.

Case 2 To produce from both the upper and lower reservoir simultaneously and sell gas to either market.

Case 3 To produce sales gas from the lower reservoir only and sell either market and at the same time producing gas from the upper reservoir, recovering liquids and injecting gas into the lower reservoir to maintain pressure in the lower reservoir.

Case 4 A sensitivity study, to produce from both upper and lower reservoirs simultaneously (as Case 2) but with reduced in-ground gas reserves (approximately 50%).

For each case, the alternatives of putting gas compression on the platform or an on-shore treatment plant were considered. The premise being that if there is no off-shore compression then the platform could be designed and operated "unmanned". Case 3 requires recycle gas compression therefore the option of on-shore sales gas compression was not pursued in this instance.

A screening study considered various development options and the preferred scheme consists of a four leg fixed steel platform with offshore compression facilities. Production is transported to shore via a submarine pipeline to further treated to produce sales gas and stabilised liquids.

2. ECONOMIC OVERVIEW

The results of the economic analysis is summarised below :

		Gas Sold to Victoria		
	Case 1	Case 2	Case 3	Case 4
1. Capital Cost (A$ Million)	250	256	257	250
2. Selling Price $/GJ				
° 10% IRR	1.17	1.24	1.39	1.04
° 15% IRR	1.84	1.93	2.14	1.84
° 20% IRR	2.71	2.81	3.09	3.00

		Gas Sold to Tasmania			
		Case 1	Case 2	Case 3	Case 4
1.	Capital Cost (A$ Million)	228	226	232	250
2.	Selling Price $/GJ				
	° 10% IRR	1.78	1.62	2.39	2.04
	° 15% IRR	3.03	2.88	3.84	3.45
	° 20% IRR	4.75	4.60	5.77	5.27

Based soley on selling price there is no substantial difference between the cases investigated, except Case 3, which is the worst case for either the Victorian or Tasmanian market.

However, from a technical view point it should be pointed out that only very preliminary engineering has been undertaken and further work will need to be carried out before a final development scheme can be selected. In particular pipeline and compression optimisation needs very careful study. These two items represent more than 30% of the total capital investment. Similarly the size and configuration of the platform needs further study and major savings in capital could be realised.

3. Sensitivity Analysis

Various sensitivity analyses have been carried out for changes in operating costs, depreciation schedule and capital investment. The resulting changes to the gas selling price are provided in Section 6 of the report.

SECTION 1

INTRODUCTION

1.1 Background

R.J. Brown - CMPS were commissioned to study various options for the development of the Yolla Gas field in Bass Strait, Australia. The objective of the investigations was to determine the selling price of the gas for various rates of return on capital invested.

Yolla field is located approximately 92 kilometres South-South West of Wilson's Promontory as shown on Figure 1.1.

This report documents the preferred development scenario. Measurements in this report are generally expressed in imperial units to compliment the data provided by Gas and Fuel Exploration N/L.

1.2 Study Philosophy

The general philosophy adopted in this study has been to utilise only accepted and proven Bass Strait development practices in line with existing producing facilities.

1.3 Scope of Study

The overall scope of work undertaken was to generally evaluate four production scenarios as set out below :

- The study is to investigate and identify various development options, and based on the development option selected, develop preliminary economics with the aim of determining the landed price of Yolla gas in Victoria and Tasmania. It can be assumed that the Victoria and Tasmanian markets are mutually exclusive of one another. It is expected that the gas earmarked for the market will come mainly from the deeper pay zone at Yolla.

- The study will also investigate the possibility of dual production from the top reservoir. The aim is to determine the feasibility of recovering oil and condensate and associated gas from the upper zone and its effect on the overall economic and landed price of gas in Tasmania and Victoria.

- Considering that some additional wells are probably required to be drilled in the later part of the life of the field to augment deliverability, the study should also address the feasibility and economics of phasing in these wells earlier for use as dry gas recycling within the deeper pay zone.

- The study should investigate the sensitivity on the landed price of gas using reserve of 190 BCF of gas and 9 million barrels of condensate in the lower zone and 10 BCF and 11 million barrels of oil in the upper zone. For this sensitivity study, the same deliverability and well requirements used in the base cases can be assumed. However, life of the field will have to be shortened to correspond with the total reserves recoverable.

? See p. 2
of Dolr RL document.
What effect does
2x of reserves have
on economics.)

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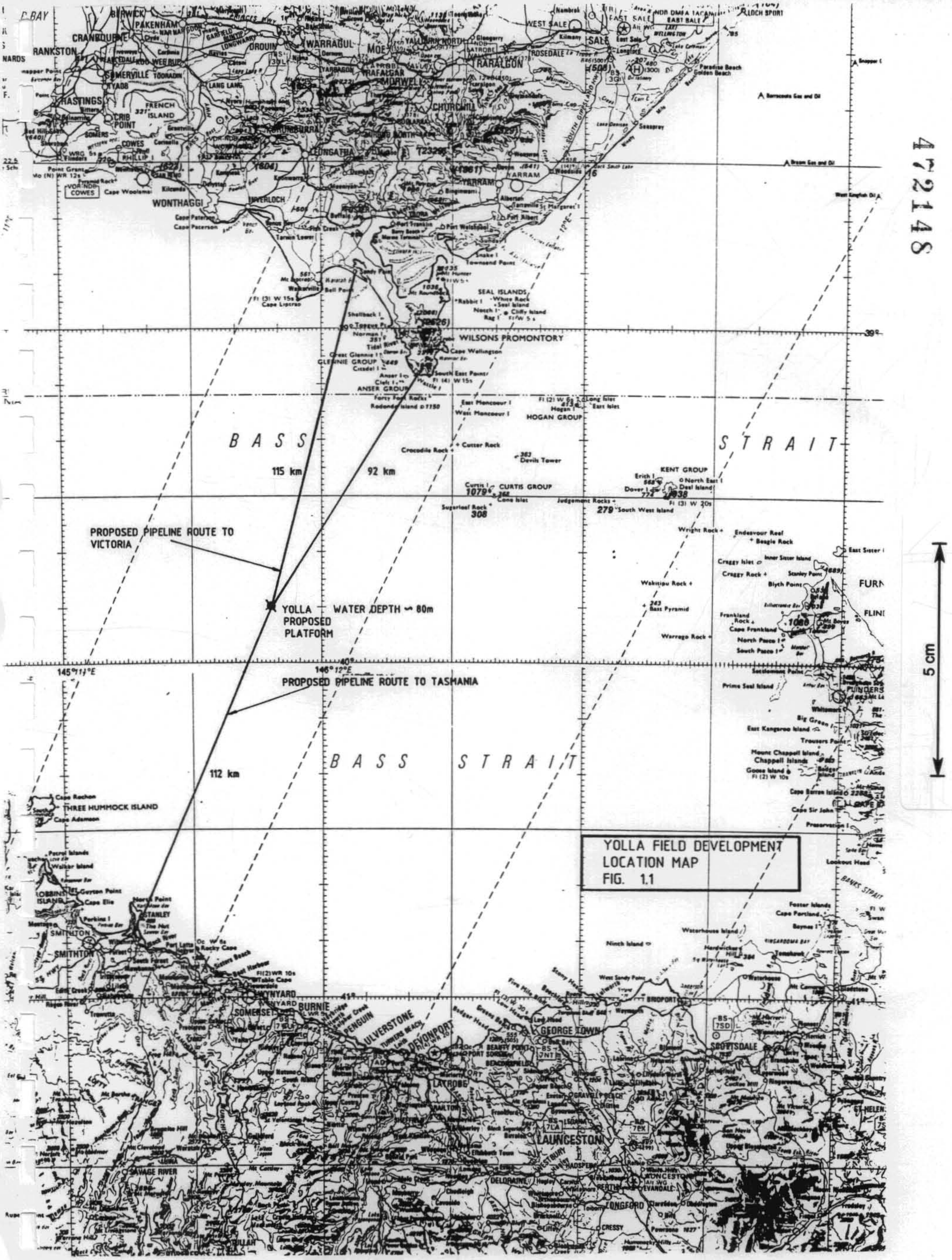

YOLLA FIELD DEVELOPMENT
LOCATION MAP
FIG. 1.1

SECTION 2

STUDY BASIS

2.1 Design Assumptions

The study has been based upon data provided by Gas & Fuel Exploration N/L and other information subsequently supplied by Gas & Fuel. The data is appended to this report.

2.2 Flow Rates

The sales gas market profiles for Victoria and Tasmania are provided in Table 2.1.

In order to determine production rates the following set of assumptions were used :

- The composition of the wellstreams for the upper and lower reservoirs were taken from the laboratory results on test samples.
- It was assumed that the wellstream composition will remain constant throughout the life of the reservoir.
- It was assumed that the wells will stop producing when the total amount of predicted gas reserves are exhausted.

In regard to Case 4, the changes in GOR and composition will effect the determined production rates to a greater or lesser extent. This is a sensitivity study case and more data input would be required to upgrade the level of confidence in the numbers.

The production rates thus determined are given in Table 2.2.

2.3 Sales Gas Specification

The sales gas specifications for both the Victorian and Tasmanian markets are as follows :

S.I. Units!

Delivery Pressure		1000 psig
Maximum Hydrocarbon Dew Point @ 1000 psia		36°F
Maximum Oxygen Content by Volume		0.2%
Maximum Total Sulphur/100 Cubic Feet		2 grains
Maximum H_2S/100 Cubic Feet		0.25 grains
Maximum Mercaptan/100 Cubic Feet		0.20 grains
Total Calorific Value/Cubic Feet	- Maximum	1100 Btu
	- Minimum	980 Btu
Wobbe Index	- Maximum	1365
	- Minimum	1235

2.4 General Design Philosophy

The design philosophy adopted has been to utilise only accepted and proven offshore development techniques with a minimum of processing facilities to be located offshore. Special attention has been given to minimise development cost while providing adequate reliability and compliance with applicable codes and regulations.

2.5 Environmental Conditions

Water depth at Yolla is approximately 80m. Calcareous sands have been assumed for the platform foundations. Mud)

It has been assumed that pipelines and gas plant construction will not be permitted in the National Park at Wilson's Promantory.

2.6 Technical Data

It is important to note that the data upon which this study is based is highly preliminary and not exhaustive. In sizing equipment and evaluation of support facilities considerable reliance was made on our past experience with similar installations. For an in depth study it is necessary to carry out extensive computer simulations regarding the process hydraulics and mass/heat balances. This was not done and only desk calculator programs were used in sizing the facilities and equipment.

2.7 Economic Analysis

It is assumed that the project will be liable for Resource Rent Tax (RRT) if net cash flows exceeds project related expenditure. Excess project related expenditure over net cash flow has been compounded at a threshhold rate of 28%.

A project contingency of 20% has been applied to capital investment. Capital equipment including the platform and pipeline has been depreciated over 5 years from first year of income.

Liquids from the field have been sold at $21/B. Too low?

Gas selling prices have been determined to provide an IRR of 10%, 15% and 20% on capital invested.

TABLE 2.1

SALES GAS MARKET PROFILES

YEARS FROM COMMISSIONING	GAS DEMAND (PJ)	
	VICTORIAN MARKET	TASMANIAN MARKET
1	30	12
2	30	14
3	30	15
4	30	15
5	30	16
6	30	16
7	30	17
8	30	17
9	24	17
10	18	17
11	12	17
12	9	17
13	6	17
14		17
15		17
16		17
17		14
18		11
19		9
20		7
21		6 /325

NOTE: It is assumed that the Victorian and Tasmanian markets are mutually exclusive of each other.

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	CASE 1				CASE 2				CASE 3			
	VICTORIA		TASMANIA		VICTORIA		TASMANIA		VICTORIA		TASMANIA	
	GAS	LIQUIDS	GAS	LIQUIDS	GAS	LIQUIDS	GAS	LIQUIDS	GAS	LIQUIDS	GAS	LIQUIDS
1	87.3	5120	39.5	2050	84.2	5490	31.7	2410	87.3	5810	87.3	2740
2	87.3	5120	40.8	2390	84.6	5420	38.0	2690	87.3	5695	87.3	2965
3	87.3	5120	43.7	2570	84.6	5420	40.9	2860	87.3	5695	87.3	3145
4	87.3	5120	43.7	2570	85.1	5355	41.4	2795	87.3	5580	87.3	3030
5	87.3	5120	46.6	2740	85.7	5300	44.9	2910	87.3	5465	87.3	3085
6	87.3	5120	46.6	2740	86.2	5240	45.5	2850	87.3	5350	87.3	2970
7	87.3	5120	49.5	2910	86.8	5180	49.0	2970	87.3	5235	87.3	3025
8	87.3	5120	49.5	2910	87.3	5125	49.5	2910	87.3	5120	87.3	2910
9	69.9	4100	49.5	2910	69.9	4110	49.5	2910	69.9	4100	69.9	2910
10	52.4	3080	49.5	2910	52.4	3080	49.5	2910	52.4	3080	52.4	2910
11	34.9	2050	49.5	2910	34.9	2050	49.5	2910	34.9	2050	34.9	2910
12	26.2	1540	49.5	2910	26.2	1540	49.5	2910	26.2	1540	26.2	2910
13	17.5	1030	49.5	2910	17.5	1030	49.5	2910	17.5	1030	17.5	2910
14			49.5	2910			49.5	2910				2910
15			49.5	2910			49.5	2910				2910
16			49.5	2910			49.5	2910				2910
17			40.8	2390			40.8	2390				2390
18			32.0	1880			32.0	1880				1880
19			26.2	1540			26.2	1540				1540
20			20.4	1200			20.4	1200				1200
21			17.5	1030			17.5	1030				1030

NOTE - CASES 1,2 & 3:

1. Recoverable gas reserves are 350 BCF lower reservoir.
2. Recoverable gas reserves are 30 BCF upper reservoir.
3. Gas rates are MMSCF/D.
4. Liquid rates are B/D.
5. Gas rates are production rates required to meet sales gas requirements.

CASE 4

	VICTORIA		TASMANIA	
	GAS	LIQUIDS	GAS	LIQUIDS
1	85.7	9140	33.3	3850
2	85.7	9140	39.1	4430
3	86.2	9040	42.5	4620
4	87.3	8830	43.7	4430
5	87.3	8830	46.6	4720
6	87.3	8830	46.6	4720
7			49.5	5020
8			49.5	5020
9			49.5	5020
10			49.5	5020

<u>NOTE - CASE 4:</u>

1. Lower Reservoir Contains : 190 BCF Gas - 9 million barrels condensate Liquids
2. Upper Reservoir Contains : 10 BCF Gas - 11 million barrels oil Liquids
3. Gas Market/Sales are same as Case 1.
4. Gas rates are MMSCF/D.
5. Liquid rates are B/D.

SECTION 3

SCREENING STUDY

3.1 General

A preliminary screening study was carried out to investigate various options for transporting gas and liquids to shore from the Yolla Field.

The study scope identified two major requirements, namely that the design philosophy should utilise only accepted and proven offshore development techniques with a minimum of offshore processing facilities. Secondly, that special efforts should be taken to minimise cost while providing adequate reliability and compliance with applicable codes and regulations.

The options that were considered included :

- Subsea wellheads free flowing to a production manifold and the free co-mingled production free flowing to shore. This scheme was rejected on the basis that flow over long distances (115km) is not a proven technology.

- Subsea wellheads flowing to a subsea multi-phase pump and then pumped production to shore. This scheme was rejected on the basis that multi-phase pumping technology is still at R&D stage. However, it will most certainly be a technology that will be extensively used in the 1990's.

- Offshore platform with various options for transporting production. The transportation options included the following schemes :

  (a) Gas and liquids transported to shore via 2 phase pipeline.

(b) Gas and liquids to shore via separate pipelines.

(c) Gas to shore via pipeline with liquids to offshore storage tanker via submarine pipeline.

Schemes (b) and (c) were rejected on the basis of much higher capital cost than scheme (a).

As a result, the preferred development consists of an offshore platform with gas and liquids being transported to shore via a 2 phase pipeline to an onshore treatment plant. The remaining question for this type of development relates to the need for offshore compression since this affects both capital cost as well as operating cost. If offshore compression is adopted the size of the submarine pipelines can be kept relatively small. On the other hand it is generally accepted practice in the hostile environment of Bass Strait that compression facilities of some size require permanent operating and maintenance manning. Hence the choice of development relates to the capital cost of offshore compression/pipeline sizing versus permanent manning/part-time manning.

The major alternatives for the Yolla development can therefore be defined as follows :

(a) Manned platform, offshore compression, small diameter pipeline to shore, OR

(b) Unmanned platform, no offshore compression large diameter pipeline to shore with onshore compression.

A third alternative is a combination of (a) and (b) above. This was not considered primarily because the two options provide maximum and minimum cases and the selection of an in between case is a major study in itself and outside the scope of this current study.

3.2 Selection of Development Scheme

To assess the impact of offshore gas compression versus onshore compression each of the four cases set out in the scope of work were investigated in a preliminary screening study. Pipeline size, separator pressure and compression requirements were calculated. Wellhead pressure and the life of the field were determined using an in-house programme which determines approximately the declining well head pressure with time.

The exception to the above was Case 3 where gas from the upper reservoir needs to be compressed in order to re-inject the dry gas into the lower reservoir. Since offshore compression is always required for this operation no onshore compression case was examined.

The resulting pipeline size and compression requirements for each case are shown in tables 3.1, 3.2, 3.3 and 3.4. In addition to these facilities the offshore compression case attracts higher capital expenditure required for offshore quarters plus larger deck size to carry the compressors and quarters and comensurately larger jacket to support this additional weight.

By inspection of Tables 3.1 to 3.4 Case 1 Gas to Victoria (or Tasmania) demonstrates the least difference in equipment and pipeline requirements between the onshore and offshore compressor options. This case was subsequently selected to show difference in capital and operating costs for the two options. For all other cases the difference in capital will be higher than Case 1. The difference in capital is shown in Table 3.5.

In this case the onshore compression option is considerably higher in capital cost than the offshore compression option. The difference is approximately $29 million. This is almost entirely due to the cost of installing a larger diameter relatively long submarine pipeline. On the other hand the operating cost for a manned platform versus an unmanned platform are considerably higher. The additional operating cost for a manned platform is estimated to be about $8,700K/year. This covers manning, helicopter for crew changes and workboats for supplies. However, full manning will not be required until well into the production life of the field (except case 3 which requires compression for gas re-injection in year 1).

Hence the choice comes down to higher early capital investment for the onshore compression options versus higher operating costs later in the field life for offshore compression options.

Based on other Bass Strait petroleum development studies that R.J. Brown - CMPS have carried out for Gas & Fuel Corporation the selling price of the product for a specified Internal Rate of Return (IRR) on investment is adversely affected to a greater extent by early investment than it is to savings in operating costs.

Therefore the choice of development for Yolla is clearly the offshore compression option which has the lower capital investment, but higher operating cost later in the life of the field.

As a sensitivity to demonstrate the effect of lower operating cost a financial analysis will be carried out for an unmanned offshore compression case which will demonstrate the benefits of both lower capital and lower operating costs.

TABLE 3.1
GAS TO VICTORIA - LOWER RESERVOIR ONLY - CASE 1
PRODUCTION PROFILE

Year	Sales Gas MMSCFD	Cumulative % Of Recoverable Gas	Wellhead Pressure	Offshore (a) Compression Requirements	Onshore (b) Compression Requirements
1	87.3	8.8	2,800	Nil	Nil
2	87.3	17.6	2,400	Nil	Nil
3	87.3	26.4	2,100	Nil	Nil
4	87.3	35.3	1,800	Nil	Nil
5	87.3	44.1	1,400	1,000 HP C	Nil
6	87.3	52.6	1,200	1,700 HP	Nil
7	87.3	61.4	800	4,000 HP	2,500 HP C
8	87.3	70.2	500	6,700 HP C	8,000 HP C
9	69.9	76.9	320/400	6,700 HP	8,000 HP
10	52.4	81.8	140/250	7,950 HP	14,700 HP 2xC
11	34.9	85.1	100/200	6,300 HP	6,800 HP
12	26.2	87.6	80/150	5,200 HP	6,200 HP
13	17.5	89.2	70/100	3,800 HP	5,150 HP

TABLE 3.1 - CONTINUED
GAS TO TASMANIA - LOWER RESERVOIR ONLY - CASE 1
PRODUCTION PROFILE

Year	Sales Gas MMSCFD	Cumulative % Of Recoverable Gas	Wellhead Pressure	Offshore (a) Compression Requirements	Onshore (b) Compression Requirements
1	34.9	3.5	3,000	Nil	Nil
2	40.8	7.6	2,800	Nil	Nil
3	43.7	12.0	2,600	Nil	Nil
4	43.7	16.4	2,500	Nil	Nil
5	46.6	21.1	2,300	Nil	Nil
6	46.6	25.8	2,100	Nil	Nil
7	49.5	30.9	2,000	Nil	Nil
8	49.5	35.7	1,800	Nil	Nil
9	49.5	40.8	1,500	Nil	Nil
10	49.5	45.7	1,300	Nil	Nil
11	49.5	50.7	1,200	200 HP 2xS	Nil
12	49.5	55.6	1,000	750 HP	Nil
13	49.5	60.6	850	1,250 HP	250 HP 2xS
14	49.5	65.6	650	2,100 HP 1xC	1,500 HP
15	49.5	70.8	500	3,000 HP	3,000 HP 1xC
16	49.5	75.8	300	4,750 HP 1xC	6,700 HP 1xC
17	40.8	76.9	150/196	6,500 HP	12,000 HP 2xC
18	32.0	82.9	120/160	6,500 HP	9,200 HP
19	26.2	85.7	100/130	4,750 HP	7,600 HP
20	20.4	87.6	80/108	4,000 HP	5,900 HP
21	17.5	89.5	70/100	3,700 HP	5,030 HP

NOTE:

(a) Based on 323 O/D pipe (12") and 1750 psig offshore separator pressure.
(b) Based on 508 O/D pipe (20").
C Install Solar Centaur Turbine Compressor Package.
S Install Solar Saturn Turbine Compressor Package.

TABLE 3.2

GAS TO VICTORIA - UPPER & LOWER RESERVOIR - CASE 2

PRODUCTION PROFILE

Year	Sales Gas MMSCFD	Wellhead Pressure	Offshore (a) Compression Requirements		Onshore (b) Compression Requirements	
1	14.2/70.0	1,500/2,900	Nil/Nil		Nil	
2	11.8/72.8	1,200/2,600	Nil/Nil		Nil	
3	11.8/72.8	1,000/2,300	225/Nil	S	250 HP	C
4	9.4/75.7	700/2,000	350/Nil		2,300 HP	
5	7.1/78.6	500/1,700	400/Nil		5,600 HP	C
6	4.7/81.5	300/1,300	350/Nil		19,500 HP	C
7	2.4/84.4	200/1,100	160/500 HP		16,500 HP	2xC
8	-/87.3	-/800	/2,200 HP	C	1,550 HP	
9	-/70.0	-/500	/4,000 HP		3,750 HP	
10	-/52.4	-/350	/4,500 HP		4,450 HP	
11	-/34.9	-/200	/5,000 HP		4,900 HP	
12	-/26.2	-/160	/4,200 HP		4,250 HP	
13	-/17.5	-/120	/3,250 HP		3,400 HP	

TABLE 3.2 - CONTINUED
GAS TO TASMANIA - UPPER & LOWER RESERVOIR - CASE 2
PRODUCTION PROFILE

Year	Sales Gas MMSCFD	Wellhead Pressure	Offshore (c) Compression (HP) Requirements		Onshore (d) Compression Requirements	
1	14.2/17.5	1,500/3,200	Nil/Nil		Nil	
2	11.8/26.2	1,200/2,950	Nil/Nil	2xR	Nil	
3	11.8/29.1	1,000/2,850	225/Nil		150	S
4	9.4/32.0	700/2,750	350/Nil		1,150	
5	7.1/37.8	500/2,600	400/Nil		2,500	S
6	4.7/40.8	300/2,450	350/Nil		5,000	2xC
7	2.4/46.6	200/2,250	160/Nil		10,500	2xC
8	-/49.5	-/2,100	-/Nil		Nil	
9	-/49.5	-/1,900	-/Nil		Nil	
10	-/49.5	-/1,700	-/Nil		Nil	
11	-/49.5	-/1,500	-/Nil		Nil	
12	-/49.5	-/1,300	-/Nil		Nil	
13	-/49.5	-/1,100	-/400		Nil	
14	-/49.5	-/950	-/800	S	300	
15	-/49.5	-/750	-/1,450	S	1,100	
16	-/49.5	-/600	-/2,250		2,000	
17	-/40.8	-/450	-/2,800		2,600	
18	-/32.0	-/350	-/2,800		2,750	
19	-/26.2	-/200	-/3,200		3,850	
20	-/20.4	-/150	-/3,500		3,650	
21	-/17.5	-/120	-/3,400		3,650	

NOTE:

(a)	Based on 356 O/D pipe (14") and 1200 psig offshore separation pressure
(b)	Based on 711 O/D pipe (28")
(c)	Based on 323 O/D pipe (12") and 1200 psig offshore separator pressure
(d)	Based on 559 O/D pipe (22")
--/--	First Number Upper Reservoir pressure Second Number Lower Reservoir pressure
S	Install Solar Saturn Turbine/Compressor Package
C	Install Solar Contaur Turbine/Compressor Package
R	Install reciprocal compressor package

TABLE 3.3

GAS TO VICTORIA - RECYCLE UPPER RESERVOIR GAS TO LOWER RESERVOIR

CASE 3 - PRODUCTION PROFILE

Year	Sales Gas MMSCFD	Wellhead Pressure	Compression Requirements	
1	87.3	1,500/2,900	600 HP/Nil	Install 600 HP recip.
2	87.3	1,200/2,600	550 HP/Nil	
3	87.3	1,000/2,300	600 HP/Nil	
4	87.3	700/2,000	600 HP/Nil	
5	87.3	500/1,700	520 HP/Nil	
6	87.3	300/1,300	420 HP/250 HP	
7	87.3	200/1,100	360 HP/1,000 HP	Install 2,500 HP
8	87.3	-/800	-/2,800 HP	
9	69.9	-/500	-/4,500 HP	Install 2,000 HP
10	52.4	-/350	-/4,800 HP	
11	34.9	-/200	-/4,800 HP	
12	26.2	-/160	-/4,200 HP	
13	17.5	-/120	-/3,300 HP	

TABLE 3.3 - CONTINUED

GAS TO TASMANIA - RECYCLE UPPER RESERVOIR GAS TO LOWER RESERVOIR

CASE 3 - PRODUCTION PROFILE

Year	Sales Gas MMSCFD	Wellhead Pressure	Compression Requirements	
1	34.9	1,500/3,200	Nil	
2	40.8	1,200/2,950	Nil	
3	43.7	1,000/2,850	750/-	Install 800 HP recip.
4	43.7	700/2,750	800/-	
5	46.6	500/2,600	700/-	
6	46.6	300/2,450	800/-	
7	49.5	200/2,250	600/-	
8	49.5	-/2,100		
9	49.5	-/1,900		
10	49.5	-/1,700		
11	49.5	-/1,500		
12	49.5	-/1,300		
13	49.5	-/1,100		
14	49.5	-/950	-/1,500	
15	49.5	-/750	-/1,200	Install 2,000 HP
16	49.5	-/600	-/1,600	
17	40.8	-/450	-/2,800	
18	32.0	-/350	-/2,800	
19	26.2	-/200	-/3,700	Install 1,000 HP
20	20.4	-/150	-/3,500	
21	17.5	-/120	-/3,400	

NOTE:

Based on 356 O/D pipe (14") and 1,350 psig offshore separator pressure

TABLE 3.4
GAS TO VICTORIA - SENSITIVITY STUDY
CASE 4 - PRODUCTION PROFILE

Year	Sales Gas MMSCFD	Wellhead Pressure	Offshore (a) Compression Requirements		Onshore (b) Compression Requirements	
1	7.1/78.6	1,500/2,650	Nil/Nil		Nil	
2	7.1/78.6	1,000/2,050	-/Nil		300 HP	S
3	4.7/81.5	800/1,350	-/Nil		1,500 HP	
4	87.3	/800	-/2,800	C	1,500 HP	
5	87.3	/250	-/12,000	3xC	12,200 HP	3xC

TABLE 3.4 - CONTINUED
GAS TO TASMANIA - SENSITIVITY STUDY
CASE 4 - PRODUCTION PROFILE

Year	Sales Gas MMSCFD	Wellhead Pressure	Offshore (a) Compression Requirements		Onshore (b) Compression Requirements	
1	7.1/26.2	1,500/2,950	Nil/Nil		Nil	
2	7.1/32.0	1,000/2,700	-/Nil		300 HP	S
3	4.7/81.5	800/1,350	-/Nil		1,500 HP	
4	/43.7	/2,150	-/Nil		Nil	
5	/46.6	/1,750	-/Nil		Nil	
6	/46.6	/1,400	-/Nil		Nil	
7	/49.5	/1,050	/500	2xC	Nil	
8	/49.5	/700	/1,800		1,300	
9	/49.5	/400	/4,100	1xC	3,700	
10	/49.5	/150	/9,000	1xC	14,300	

NOTE:

(a)	Based on 400 O/D pipe (16") and 1200 psig offshore separator pressure
(b)	Based on 800 O/D pipe (31.5")
C	Install Solar Centaur Turbine Compressor Package
S	Install Solar Saturn Turbine Compressor Package

TABLE 3.5
PRELIMINARY CAPITAL COST DIFFERENCES(1) BETWEEN ONSHORE & OFFSHORE COMPRESSION
GAS TO VICTORIA OPTION - (A $ K)

ITEM	CASE 1 OFFSHORE	ONSHORE
° Compression Facilities	-	2,300
° Submarine Pipeline, offshore 323, onshore 508mm		
- Materials	-	11,840
- Installation	-	16,800
° Platform	2,060	-
TOTAL:	2,060	30,940

NOTE(1): Capital Cost Differences refers to the difference in capital cost to install equipment or facilities over and above the lowest cost option. For example, Case 1 with offshore compression requires a 323mm submarine pipeline but a 508mm pipeline is required for the onshore compression option. The additional capital to install the 508mm pipeline over the 323mm pipeline of $28,640K is the "Capital Cost Difference".

SECTION 4

YOLLA DEVELOPMENT

4.1 General Concept

As previously discussed, the preferred development for the Yolla field for all cases consists of a fixed steel production platform with gas and liquids transferred to an onshore treatment plant via a single submarine pipeline.

An offshore three phase separator on the platform removes the produced water. The gas is subsequently compressed and sent to shore via the pipeline along with the condensate and oil.

The gas and liquids are further treated at an onshore plant at either Victoria or Tasmania where the gas is processed to sales gas specifications and the liquids stock piled in storage tanks.

The offshore development is serviced by work boats from a marine supply base assumed to be within 150 kilometres of the platform. Helicopter service is operated from a helipad located at the onshore plant.

4.2 Offshore Platform Facilities

4.2.1 Offshore Production Philosophy

The approach taken has been to keep the extent of off-shore processing to the minimum necessary for security of supply.

Case 1 The produced combined gas and liquids from all producing wells is mingled in an inlet/test/drain manifold. The combined stream feeds a 3 phase horizontal production separator sized for the maximum combined flow rate of all wells. The separated condensate/oil is pumped back into the gas stream for transportation to shore in a 2 phase flow pipeline. Separated water from the production separator is further treated in a Vortoil separator before going to the skimmer pile.

A test separator is provided to enable performance of any individual well to be checked. The test separator is the same size and rating as the production separator to provide 100% standby capacity, it would have its own condensate/oil pump and Vortoil separator.

A pig launcher is provided for pigging the pipeline to shore.

As wellhead pressure falls, gas turbine driven centrifugal compressors are required to achieve the forecast sales gas quantities.

Case 2 The production streams from the upper and lower reservoirs are kept separate and fed to independent 3 phase horizontal production separators. The liquid treatment systems are as per case 1, again with a test separator designed for the maximum conditions to provide 100% standby of either production separator.

Offshore compression is required to compress the separator off gas from the upper reservoir before being mixed with that of the lower reservoir and entering the "to shore" pipeline.

As for Case 1, the wellhead pressure will decline and gas turbine driven compressors are required off shore to achieve the required discharge pressure to meet the sales gas quantities.

Case 3 This is identical to Case 2 except that the off gas from the upper production separator is always compressed and recycled to the lower reservoir. Thus off-shore compression is necessary for this duty from the beginning of production.

Case 4 The production equipment is the same as for Case 2.

4.2.2 Compressor Philosophy

The in-depth evaluation of compressor is beyond this study, we have therefore used a simple philosophy to allocate compression requirements.

(a) For the Victorian market, it is assumed that alternative gas supply sources are available and that security of supply is not of prime importance. Thus 100% standby is not necessary.

(b) For the Tasmanian market, it is assumed that security of the supply is of paramount importance because there is only the one source of gas. Thus we have allowed for 100% standby, whenever compressor failure would reduce gas flow below 70/80% of predicted sales.

Two sizes of gas turbine driven compressors have been allowed for :

(a) Solar Saturn, producing approximately 1200 shp.
(b) Solar Centaur, producing approximately 3800 shp.

It has been assumed that a compressor/turbine combination can be adjusted or modified to meet operational conditions provided that sufficient horsepower is available. This may mean running compressors in series or changing the compression ratios. A turbine/compressor efficiency of 70% has been used.

4.2.3 Other Platform Equipment

In addition to the production equipment referred to above other plant and equipment will be necessary in all cases, these include :

(a) Utilities

- Blow down vessel.
- Vent scrubber and gas flare.
- Injection pumps for corrosion control and to inhibit hydrate formation, plus storage tanks for each chemical.
- Well kill system, comprising storage tank and high pressure pump connected to wellhead.

(b) Fire Protection System

The fire protection system will consist of diesel engine driven vertical pumps, 150mm ring main and water deluge system. All piping will be in cupro-nickel in accordance with latest practices. In addition a bladder foam storage tank, local hose stations, hydrants and fire monitors will be provided at strategic locations. The ring main will be continuously pressurised from the service water system. A fire, gas and smoke detection system will be provided as part of the overall fire protection facilities. In addition BCF cylinders and distribution system will be provided for fire protection of the electrical switchgear and control room.

(c) Vents and Drain

All open and closed platform drains will be directed to a sump. The hydrocarbon liquids collected in the sump will be re-injected into the production separators using a sump pump and two HP plunger type re-injection pumps.

(d) Life Support and Maintenance Facilities

These will include the following :

- Living quarters for 24 personnel
- Central control and communications room
- Chemical and parts store
- Pressurised workshop to allow welding and hot work
- Two survival capsules
- Platform crane (Favco 25/10k)

(e) Electric Power Supply

This shall include the following :

- Generator set - 2 off
- Lighting and power
- Battery back up of emergencies and communication
- Maintenance (welding, life support)
- ESD
- Navigation lighting

4.3 Platform Structure

The platform jacket is a 4 leg structure fixed to the seabed with 4 driven sleeve piles to 15m sub mudline. At each sleeve pile an insert pile is drilled and grouted to a penetration of approximately 100m sub mudline. The sleeve pile is welded to the jacket leg with the annulus between the insert pile and the sleeve pile grouted.

Drilled and grouted piles techniques are well suited for the Bass Strait calcareous sands and have been successfully used by Esso/BHP on all of their Bass Strait platforms.

The structure has 6 well slots adjacent to the face of the jacket for access by jack-up drilling rig. The legs will have boat fenders and a small combination boat landing/riser guard.

The deck has two levels with the main deck kept generally clear for future work-over operation and the cellar deck holding the majority of the equipment. The quarters are located directly below the helideck.

Platform weight summary is provided below :

Components	Steel Weight (Tonnes)
Deck	400
Jacket	1050
Piles	870

Fabrication of the decks, jacket, conductors and piles will be carried out in Australia.

It has been assumed that a derrick barge similar to J. Ray McDermott's DB101 will be available to lift and install the jacket directly from the jacket tow out barge. A jack-up will subsequently drill and grout the jacket piles and later be used for the development drilling. The derrick barge will also lift onto the jacket the decks, living quarters and helideck modules, which will be transported directly by barge from the fabrication yard(s).

4.4 Pipelines

4.4.1 Offshore Submarine Pipeline

The submarine pipeline to shore is uninsulated except for the affects of the corrosion coating and concrete weight coating for stability. Cathodic protection will be provided to the pipeline and pipeline riser by a sacrificial anode system.

Operating conditions for the pipeline are onshore discharge pressure of 1050 psig, minimum anticipated sea bed temperature is approximately 11°C and a pipeline roughness factor of 0.002. Operating experience with other uninsulated Bass Strait gas lines indicate that hydrates may form in the pipeline at these operating pressures and temperatures. However, glycol will be injected into the pipeline to inhibit hydrate information and the glycol will be subsequently collected at the onshore gas plant for re-use.

The pipeline will be regularly pigged to clear the line of sand, corrosion deposits, any liquids and other deliterious materials.

The pipeline will be installed from the derrick/lay barge used for the installation of the platform and trenching of the pipeline has not been included.

The closest Victorian landfall to Yolla is Wilson's Promontory which is approximately 92km N.N.E. of Yolla. However, the land around Wilson's Promontory is part of a National Park system and for this study is assumed to be environmentally sensitive. Accordingly the routing of the pipeline to Victoria is from Yolla to Sandy Point as shown on Figure 1.1 and is clear of the national park. The route length is approximately 115km.

The routing of the pipeline to Tasmania is from Yolla to Stanley, which is the closest Tasmanian landfall.

Site visits of these landfalls will be needed to confirm their suitability.

4.4.2 Onshore Pipeline to Gas Plant

Once onshore the pipeline will travel approximately 5 kilometres to a new gas processing plant. The delivery pressure will be approximately 1050 psig.

Pipeline scraper receiving facilities will be installed at the gas plant.

4.5 Onshore Treatment Plant

The onshore treatment plant includes both gas and liquid facilities. The incoming 2 phase flow will enter a slug catcher which also operates as a first stage (high pressure), 2 phase separator.

The separated liquids then pass to an intermediate 3 phase horizontal separator, and the condensate/oil stream to a 3rd stage, (low pressure) 3 phase separator before going to tank storage. Condensate storage capacity is a nominal 14 days of maximum production. Any water removed in the intermediate and low pressure separators is further treated in an API separator before passing to an evaporation pond. Oil recovered from the API separator will be pumped direct to the tank storage.

Off gas from the intermediate and low pressure separator will be used as fuel gas in other areas of the treatment plant.

Off gas from the slug catcher will be treated to first remove excess CO_2 then to dehydrate to pipeline specifications.

The CO_2 removal system will be either an Amine Unit or Benfield process plant; the dehydration unit will be a Tri-ethylene glycol plant (TEG).

For those cases where gas is for Victorian markets then single gas treatment units of 100% duty are envisaged. For the Tasmanian market however, 2x100% duty plants are envisaged to give full security of supply.

Prior to export the gas will go through a fiscal metering station.

4.5.1 Plant Utilities

The following utilities have been allowed for :

- A compressed and instrument air skid consisting of two air compressors, heatless driers, instrument air receiver, compressed air volume tank and distribution system.

- Diesel storage tank and two circulation pumps.
- Flare knockout drums and elevated flare.
- Closed and open drain system.
- Evaporation pond.

- 200,000 gallon fire water tank including two 100 L/sec diesel driven fire water pumps and distribution system in carbon steel. This will include foam generating equipment, water deluge sprinklers, fire monitors and hose stations.

- Central control and communications building.
- Gatehouse, office.
- Maintenance store and workshop.
- Helicopter pad.

4.5.2 Future Developments

Future developments of the onshore facilities that could be considered include the extraction of ethane and LPG components for sale. These were not covered in this study because the quantities appeared too small to have much impact on the overall financial return.

4.6 Onshore Support Facilities

4.6.1 Helipad

Crew changes and other personnel visits to the platform will be by helicopter operating from a helipad at the onshore plant. Helicopters will be 13 man, twin engine, and equipped for night flying.

The helipad will have a workshop, small warehouse, waiting room and flight check-in facilities. Site services such as potable water, fire fighting, re-fuelling, sewerage disposal and communications have been included.

4.6.2 Marine Base

A marine base for workboats and other marine activities will be located within 150 kilometres of the Platform.

The base will have a small wharf area large enough to handle two workboats, workshop, warehouse, office, canteen and helipad. Site services, access road, and dredging have been included.

4.7 Development Drilling

It is assumed that the original discovery well Yolla-1, which was left suspended, can be successfully re-entered.

Drilling will need to be carried out from a jack-up drilling rig. The alternative would be for the platform to be a combination drilling and production platform. However, the platform would need to be much larger to support a drilling rig and for the small number of wells required at Yolla is not considered to be an attractive option.

The development drilling schedule for Victoria and Tasmania is shown below. It is assumed that the exploration well can be completed as a development well.

Drilling Schedule

	Pre-Production (Year)	Production (Year)
Tasmania:		
Case 1 & 2	1 in Year 4	1 in Year 11, 1 Year 15
Case 3	3 in Year 4	-
Case 4	1 in Year 4	-
Victoria:		
Case 1 & 2	3 in Year 4	2 in Year 7
Case 3	5 in Year 4	-
Case 4	3 in Year 4	-

For Case 3 it is assumed all the wells need to be drilled pre-production in order to re-cycle the gas from the upper reservoir. For Case 4, which is assumed to be a sensitivity case, it is further assumed that no further wells are required because of the relatively short production time frame (max. 6 years Victoria, 10 years to Tasmania).

SECTION 5

CAPITAL AND OPERATING COST ESTIMATES

5.1 Capital Costs

Total estimated capital costs for the initial development of the Yolla field are summarised below.

		Capital Cost A$ Millions		
	Case 1	Case 2	Case 3	Case 4
Gas to Victoria	249.73	255.83	256.36	250.12
Gas to Tasmania	228.19	225.58	232.04	249.88

Detailed breakdown of the costs are provided in Table 5.1 and 5.2.

The capital costs estimate has been developed on the basis of a combination of unit costs, written quotations, in-house data and telephone quotations. All costs shown are in first quarter 1989, Australian dollars.

Equipment lists, weights, size, costs, etc., for the platform and onshore plant are summarised in the Appendices A, B, C.

Offshore construction of the platform and the submarine pipeline have been developed using the installation times shown in Figure 5.2 and a unit rate for the derrick barge of $260,000/day whilst operating in construction mode and $300,000/day whilst laying pipe.

Drilling and grouting of the jacket piles, and conductors and work on well completions by the jack-up have been costed at $125,000/day.

A weather downtime of 40% has been applied to all derrick barge installation times. In addition an allowance of 15 days of derrick barge time has been included to cover industrial unrest during platform and pipeline construction. A derrick barge standby rate of $300,000/day has been used.

Each item shown in the main body of the estimate includes an allowance for design and project management as it is assumed that the project would be put out to tender in discrete packages.

An overall project contingency of 20% has been applied to all items in the estimate except the allowance for industrial unrest.

The costs of any imported materials and/or equipment have been converted to Australian dollars at the exchange rate of A$1.00 = US$0.80.

5.2 Operating Costs

Operating costs have been developed for the various components of the project. Broadly the categories covered are platform production costs, submarine and onshore pipeline maintenance and inspection costs, gas plant processing costs, support base costs, insurance and overhead.

5.2.1 Offshore Production Costs

Platform production costs have been estimated for a manned and an unmanned operation. For the unmanned operation it is assumed that the platform will be periodically visited for routine inspection and maintenance. Workers will be transported via helicopter. If necessary workers can stay overnight.

Costs for a manned operation are based on a permanent 24 man crew being on the platform, working two weeks on and two weeks off. It is assumed that the workforce will all come from the local region. That is, no interstate travel will be incurred by the new.

The offshore production costs will cover the following items :

- Manning
- Catering
- Platform maintenance
- Platform damage repair
- Underwater inspection and cleaning
- Chemical injection
- Other consumables

The annual cost for these items has been estimated to be $1.9 million for unmanned facilities and $5.08 million for manned operation.

5.2.2 Helicopter and Workboats

Helicopter operating costs are based on a long term lease and maintenance of a fully operational 13 man twin engine helicopter. The estimate has allowed for 20 trips per month for the manned operation and 4 trips per month for the unmanned operation.

Workboat costs are based on a 300 kilometre round trip, six trips per month for the manned operation and one trip per month for the unmanned facility.

Full back-up and service at the helipad and marine base has been included. The annual transportation costs have been estimated to cost $8.1 million for the manned and $1.21 million for the unmanned operation.

5.2.3 Onshore Pipeline and Gas Plant

Operating costs for the onshore pipeline and gas plant are based on the plant operating 365 days per year. It is assumed that the workforce will all come from the local region. The equipment proposed for onshore facilities is common throughout the industry, it is well proven and requires little day to day maintenance other than normal oil level checks etc.

Manning levels can therefore be kept low. An operator needs to be available at all times, this can be achieved by working 2x12 hour shifts each day and rotating 3 men.

The operators require support from tradespersons (e.g. instrument technicians, fitters) and this is best provided on an as needed basis under sub-contract.

Major overhauls or modifications will be handled by specialist companies.

The operating costs cover the following items :

- Manning
- Plant maintenance
- Plant repair
- Pipeline surveillance
- Materials and other consumables
- Equipment hire

The annual cost for these items has been estimated to cost $0.58 million for the Victorian plant and $0.52 million for the Tasmanian plant.

5.2.4 Annual Insurance

Insurance premiums for the project have been estimated on the following basis :

° Offshore platform	0.5%
° Offshore pipeline	0.3%
° Onshore plant and pipeline	0.2%

Estimated annual insurance premium is $0.55 million.

5.2.5 Indirect Costs

Indirect costs are made up of two components. The first cost covers the establishment costs and is a once off charge against the project. It is meant to cover such items as :

- Establishing a local office
- Hiring costs of personnel
- Office equipment and furniture
- Re-location costs
- Some housing
- Cars and commercial vehicles
- Stores
- Establishment of a head office group

The once off establishment cost during the development commissioning phase is estimated to cost $0.5 million.

Indirect operating costs will cover the day to day running costs of the above items and the management and administration of the project as a whole. These costs have been estimated to be $0.3 million per year.

5.3 Working Capital

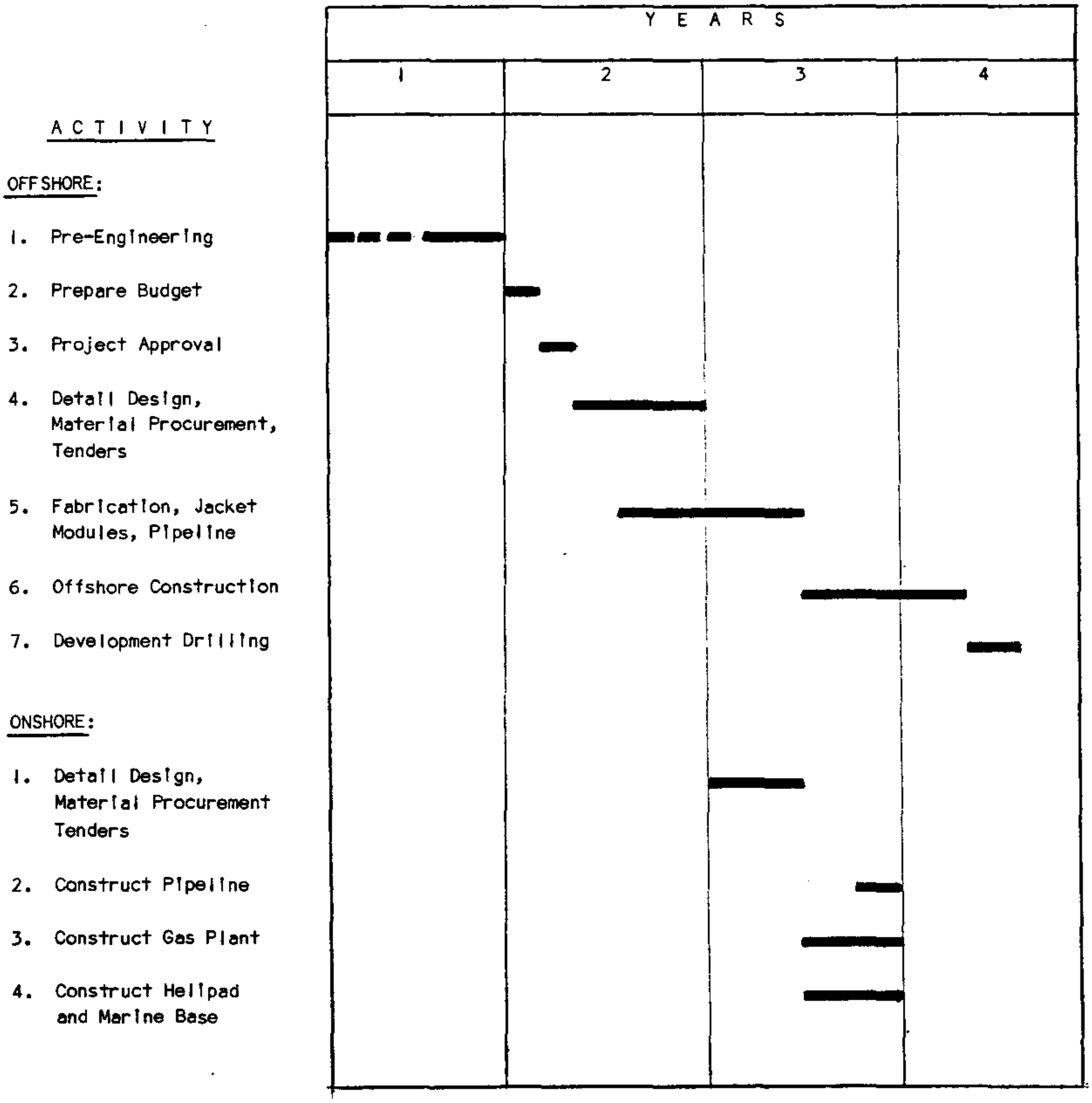
As is normal for a resource project a working capital fund has been included. The fund is based on 2% of the investment capital and $5.0 million and $4.6 million have been included for this purpose for the Victorian and Tasmanian cases respectively.

5.4 Platform Removal

An allowance has been made for platform removal to be carried out at the end of the field life. It assumes that a derrick barge will be mobilised to remove the platform and pipeline. No salvage value has been assumed. Platform removal has been estimated to cost $20.0 million.

FIGURE 5.3

YOLLA DEVELOPMENT SCHEDULE



5.5 Well Costs

As per the study brief well workovers are assumed to cost $250,000 once every two years.

Development wells have been taken to cost $10 million including drilling and completion.

TABLE 5.1 GAS TO VICTORIA

SUMMARY OF CAPITAL COSTS

(FIRST QUARTER, A$ 1989 MILLIONS)

ITEM		CASE 1	CASE 2	CASE 3	CASE 4
1.	Jacket, deck conductors and piling	15.69	15.69	15.69	15.69
2.	Equipment modules, quarters and helipad	20.69	18.76	20.84	25.84
3.	Offshore installation with derrick barge	35.18	35.18	35.18	35.18
4.	Offshore hook-up on platform	2.40	2.40	2.40	2.40
5.	Offshore pipeline	58.30	65.26	65.26	73.46
6.	Development drilling	52.20	52.20	52.20	31.20
7.	Site investigations, certification, preliminary studies	1.00	1.00	1.00	1.00
8.	Onshore pipeline	1.10	1.10	1.10	1.10
9.	Onshore gas plant	7.55	7.55	7.55	7.55
10.	Helipad and marine base	8.23	8.23	8.23	8.23
11.	Construction insurance - 1%	2.02	2.07	2.10	2.03
12.	Project contingency - 20%	40.87	41.89	42.31	40.94
13.	Allowance for industrial unrest	4.50	4.50	4.50	4.50
	TOTAL:	249.73	255.83	256.36	250.12

TABLE 5.2 GAS TO TASMANIA

SUMMARY OF CAPITAL COSTS

(FIRST QUARTER, A$ 1989 MILLIONS)

ITEM		CASE 1	CASE 2	CASE 3	CASE 4
1.	Jacket, deck conductors and piling	15.69	15.69	15.69	15.69
2.	Equipment modules, quarters and helipad	24.94	23.09	21.34	27.09
3.	Offshore installation with derrick barge	35.18	35.18	35.18	35.18
4.	Offshore hook-up on platform	2.40	2.40	2.40	2.40
5.	Offshore pipeline	56.96	56.96	63.74	72.70
6.	Development drilling	33.20	33.20	33.20	33.20
7.	Site investigations, certification, preliminary studies	1.0	1.0	1.0	1.0
8.	Onshore pipeline	1.1	1.1	1.1	1.1
9.	Onshore gas plant	5.86	5.86	5.86	5.86
10.	Helipad and marine base	8.23	8.23	8.23	8.23
11.	Construction insurance - 1%	1.85	1.83	1.88	2.03
12.	Project contingency - 20%	37.28	36.54	37.92	40.90
13.	Allowance for industrial unrest	4.5	4.5	4.5	4.5
	TOTAL:	228.19	225.58	232.04	249.88

3 Wells.

SECTION 6

ECONOMIC ANALYSIS

6.1 General

The prime objective of the analyses has been to determine the selling price of Yolla gas to achieve 10%, 15% and 20% Internal Rate of Return (IRR) on the project.

The base data used in the evaluations are as follows :

- Production to commence 5 years after development start.
- Inflator 0%
- Deflator 0%
- 100% equity financing
- 39% company tax
- Project contingency 20%
- Gas delivery at onshore Victoria or Tasmania
- 95% of capital equipment is depreciable over five years from year of first income.
- Resource rent tax applicable
- Threshold limit for RRT calculations is 28%
- Previous exploration well expenditure was A$10 million in 1985
- LIquids sold at A$21.00 per barrel.

6.2 Economic Analysis

6.2.1 Gas to Victoria

Economic analysis carried out for gas being sold in Victoria for cases 1, 2, 3 and 4 gave the following results :

IRR	Selling Price $/GJ			
	Case 1	Case 2	Case 3	Case 4
10%	1.17	1.24	1.39	1.04
15%	1.84	1.93	2.14	1.84
20%	2.71	2.81	3.09	3.00

The full cash flow analyses for these cases are presented in Appendix D to this report. The Analyses show that resource rent tax is not applicable to any of the cases for IRR of 10% or 15%.

Based upon the required selling price of the gas for a given IRR there is no appreciable difference in the cases analysed, however, Cases 1 and 4 are marginally the best cases.

6.2.2 Gas to Tasmania

The gas selling price for gas sold in Tasmania was analysed in a similar fashion to that carried out for Victoria. The results are as follows :

IRR	Selling Price $/GJ			
	Case 1	Case 2	Case 3	Case 4
10%	1.78	1.62	2.39	2.04
15%	3.03	2.88	3.84	3.45
20%	4.75	4.60	5.77	5.27

Resource rent tax is not applicable. All cases are below the RRT threshold limit.

Case 2 is marginally the best case, closely followed by Case 1.

6.3 Gas Selling Price Sensitivity

6.3.1 Operating Cost

In Section 3 of this report the operating costs for the project for a manned or unmanned platform were discussed. To test the sensitivity of higher or lower operating costs on the gas selling price two additional sensitivity cases were analysed.

Case 1, with 15% IRR for both Victoria and Tasmania was re-analysed for the following conditions.

1. The offshore platform is run as a fully manned operation for the entire life of the field.
2. The offshore platform is run as an unmanned operation for the entire life of the field.

The results of these analyses are as follows :

Selling Price $/GJ - Case 1

	Gas to Victoria		Gas to Tasmania	
IRR	Manned	Unmanned	Manned	Unmanned
15%	2.03	1.66	3.57	2.90

For gas to Victoria the difference in price is about ±$0.18/GJ when compared to the base case.

For gas to Tasmania the difference is -$0.13 and +$0.55 when compared to the base case. There is less benefit for the unmanned case because the savings in operating cost only commence in Year 11 of production and the discounted benefits have much less effect on the cash flow. However, there is considerable benefit in running the development as an unmanned facility.

6.3.2 Production Rates

Gas selling price sensitivity to production rates can be indirectly analysed by comparing Case 1 Gas to Victoria with Case 1 Gas to Tasmania. Allowing for the fact that there are some differences in capital and operating cost expenditure, the major difference is the much higher earlier production rates for gas to Victoria. This changes the gas selling price by at least $1/GJ for the 15% IRR case.

6.3.3 Depreciation

Depreciation Schedule

Depreciation of platform and plant has been made over 5 years. New Government tax regulations require depreciation over the life of the plant. To account for this, Case 1 Victoria and Tasmania have been re-analysed for changes in selling price for a 10 year depreciation schedule.

The results of these analyses are as follows :

Selling Price $/GJ - Case 1

	Gas to Victoria		Gas to Tasmania	
IRR	5 Year Depreciation	10 Year Depreciation	5 Year Depreciation	10 Year Depreciation
10%	1.17	1.26	1.78	1.89
15%	1.84	1.97	3.03	3.23
20%	2.71	3.02	4.75	5.02

As would be expected the selling price for the gas increases with the 10 year depreciation schedule.

Exploration Well Cost

The initial exploration well was included in the cash flow at a cost of A$10 million. Case 1 Victoria and Tasmania have been re-analysed for an inflated well cost of A$30 million and depreciation over 10 years. The selling price of the gas is substantially increased as set out below.

SELLING PRICE $/GJ - CASE 1

(10 year depreciation and exploration well cost of A$30 million)

IRR	Victoria	Tasmania
10%	1.64	2.43
15%	2.64	4.29
20%	5.07	8.49

APPENDIX A

MAJOR OFFSHORE EQUIPMENT AND COMPRESSION FACILITIES
GAS TO VICTORIA

TABLE A1

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 1:				
Production Separator	87.3MMSCFD 2000 psi @ 150°F	42" dia x 10" S/S(H)	12,000	65,000
Test Separator	87.3MMSCFD 2000 psi @ 150°F	42" dia x 10" S/S(H)	15,000	75,000
Vortoil Water Separator 1	3,000 BPD 2000 psi @ 150°F	6" dia x 8' S/S(H)	1,500	50,000
Vortoil Water Separator 2	3,000 BPD 2000 psi @ 150°F	6" dia x 8' S/S(H)	1,500	50,000
Production Liquids Pump	5120 BPD/2000 psi	3" x 4"	2,500	25,000
Test Liquid Pump	5120 BPD/2000 psi	3" x 4"	2,500	25,000
Recovered Oil Pump	200 PBD/2000 psi	1" x 2"	1,000	15,000
Power Generation Fuel Gas Skid	200 PBD/2000 psi	1" x 2"	1,000	80,000
Inlet/Test Manifold	200 PBD/2000 psi	1" x 2"	1,000	50,000
Pig Launcher Assembly	200 PBD/2000 psi	1" x 2"	1,000	20,000
			TOTAL:	455,000

TABLE A2

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 1:				
High Pressure Production Separator	87.3MMSCFD 2,000 psig @ 150°F	42" dia x 10' S/S(H)	12,000	65,000
Low Pressure Production Separator	14.2MMSCFD 1,500 psig @ 150°F	24" dia x 10' S/S(H)	10,500	55,000
Test Separator	14.2MMSCFD 2,000 psig @ 150°F	24" dia x 10' S/S(H)	13,000	65,000
Vortoil Water Separator 1	3,000 BPD 2,000 psig @ 150°F	6" dia x 8' S/S(H)	1,500	50,000
Vortoil Water Separator 2	2,000 BPD 1,500 psig @ 150°F	4" dia x 8' S/S(H)	1,500	50,000
Vortoil Water Separator 3	2,000 BPD 1,500 psig @ 150°F	4" dia x 8' S/S(H)	1,500	50,000
High Pressure Liquids Pump	5,125 BPD/1,200psig	3" x 4"	2,500	25,000
Low Pressure Liquids Pump	1,380 BPD/1,200psig	2" x 3"	2,500	20,000
Recovered Oil Pump	200 BPD/1,200 psig	1" x 2"	1,000	15,000
Power Generation Fuel Gas Skid				80,000
Inlet/Test Manifold				80,000
Pig Launcher Assembly				20,000
			TOTAL:	475,000

TABLE A3

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 5:				
Gas Compressor No.1	Solar Centaur	3,800 HP	40,000	2,300,000 300,000
YEAR 8:				
Gas Compressor No.2	Solar Centaur	3,800 HP	40,000	2,300,000 300,000
				Installation Later
			TOTAL:	5,200,000

TABLE A4

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 3:				
Gas Compressor No.1 (Booster Compressor)	Solar Saturn	1,200 HP	17,500	1,500,000
YEAR 8:				
Gas Compressor No.2	Solar Centaur	3,800 HP	40,000	2,300,000 300,000
				Installation
			TOTAL:	4,100,000

TABLE A5

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 1:				
Gas Compressor No.1 (Recycle)	Recip.	600 HP	16,000	800,000
YEAR 6:				
Gas Compressor No.2	Solar Saturn	1,200 HP	17,500	1,500,000 300,000
YEAR 8:				
Gas Compressor No.3	Solar Centaur	3,800 HP	40,000	2,300,000 300,000
			TOTAL:	5,200,000

TABLE A6

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 4:				
Gas Compressor No.1	Solar Centaur	3,800 HP	40,000	2,300,000 300,000
YEAR 5:				
Gas Compressor No.2	Solar Centaur	3,800 HP	40,000	2,300,000
Gas Compressor No.3	Solar Centaur	3,800 HP	40,000	2,300,000
Gas Compressor No.4	Solar Centaur	3,800 HP	40,000	2,300,000
				500,000
			TOTAL:	10,000,000

APPENDIX B

MAJOR OFFSHORE EQUIPMENT AND COMPRESSION FACILITIES GAS TO TASMANIA

TABLE B1

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 1:				
Production Separator	49.5MMSCFD 1,500 psig @ 150°F	36" O/D x 10' S/S(H)	8,000	60,000
Test Separator	49.5MMSCFD 1,500 psig @ 150°F	36" O/D x 10' S/S(H)	10,000	70,000
Vortoil Water Separator No.1	2,000 BPD 1,500 psig @ 150°F	4" O/D x 8' S/S(H)	1,500	50,000
Vortoil Water Separator No.2	2,000 BPD 1,500 psig @ 150°F	4" O/D x 8' S/S(H)	1,500	50,000
Production Liquids Pump	2910 BPD/1500 psi	2" x 3"	2,000	20,000
Test Liquid Pump	2910 BPD/1500 psi	2" x 3"	2,000	20,000
Recovered Oil Pump	200 BPD/1500 psi	1" x 2"	1,000	15,000
Power Generation Fuel Gas Skid				80,000
Inlet/Test Manifold				50,000
Pig Launcher Assembly				20,000
			TOTAL:	435,000

TABLE B2

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 1:				
High Pressure Production Separator	49.5MMSCFD 2,000 psig @ 150°F	36" dia x 10' S/S(H)		
Low Pressure Production Separator	14.2MMSCFD 1,500 psig @ 150°F	24" dia x 10' S/S(H)	10,500	55,000
Test Separator	14.2MMSCFD 2,000 psig @ 150°F	24" dia x 10' S/S(H)	13,500	65,000
Vortoil Water Separator 1	2,000 BPD 2,000 psig @ 150°F	4" dia x 8' S/S	1,500	50,000
Vortoil Water Separator 2	1,500 BPD 1,500 psig @ 150°F	4" dia x 8' S/S	1,500	50,000
Vortoil Water Separator 3	1,500 BPD 1,500 psig @ 150°F	4" dia x 8' S/S	1,500	50,000
High Pressure Liquids Pump	2,910 BPD/1200 psig	2" x 3"	2,000	20,000
Low Pressure Liquids Pump	1,380 BPD/1200 psig	2" x 3"	2,000	20,000
Power Generation Fuel Gas Skid				80,000
Inlet/Test Manifold				60,000
Pig Launcher Assembly				20,000
			TOTAL:	485,000

TABLE B3

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 11:				
Gas Compressor No.1	Solar Saturn	1,200 HP	17,500	1,500,000
Gas Compressor No.2	Solar Saturn	1,200 HP	17,500	1,500,000
				400,000
YEAR 14:				
Gas Compressor No.3	Solar Centaur	3,800 HP	40,000	2,300,000
				300,000
YEAR 15:				
Gas Compressor No.4	Solar Centaur	3,800 HP	40,000	2,300,000
				300,000
			TOTAL:	8,600,000

TABLE B4

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 3:				
Compressor No.1	Recip.	600 HP	16,000	800,000
Compressor No.2 (Booster Compressor)	Recip.	600 HP	16,000	800,000
YEAR 14:				
Compressor No.3	Solar Saturn	1,200 HP	17,500	1,500,000 300,000
YEAR 15:				
Compressor No.4	Solar Saturn	1,200 HP	17,500	1,500,000 300,000
YEAR 16:				
Compressor No.5	Solar Centaur	3,800 HP	40,000	2,300,000 300,000
			TOTAL:	7,800,000

TABLE B5

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 3:				
Gas Compressor No.1	Solar Saturn	1,200 HP	17,500	1,500,000
Gas Compressor No.2	Solar Saturn	1,200 HP	17,500	1,500,000
YEAR 16:				
Gas Compressor No.3	Solar Centaur	3,800 HP	40,000	2,300,000
				300,000
			TOTAL:	5,600,000

TABLE B6

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 7:				
Gas Compressor No.1	Solar Centaur	3,800 HP	40,000	2,300,000
Gas Compressor No.2	Solar Centaur	3,800 HP	40,000	2,300,000
				400,000
YEAR 9:				
Gas Compressor No.3	Solar Centaur	3,800 HP	40,000	2,300,000
				300,000
YEAR 10:				
Gas Compressor No.4	Solar Centaur	3,800 HP	40,000	2,300,000
				300,000
			TOTAL:	10,200,000

APPENDIX C

MAJOR ONSHORE EQUIPMENT AND COMPRESSION VICTORIA AND TASMANIA

TABLE CI

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 1:				
Slug catcher/first stage Separator	49.5MMSCFD/3000BPD 1,050 psig @ 100°F	42" dia x 30' S/S	32,000	160,000
2nd Stage Separator	5MMSCFD/3,000 BPD 450 psig @ 100°F	20" dia x 10' S/S	2,000	40,000
3rd Stage Separator	2MMSCFD/2,910 BPD 450 psig @ 100°F	20" dia x 10' S/S	2,000	40,000
API Separator	200 BPD			40,000
Condensate Tank No.1	2,500 BBL	80' dia x 30' H		400,000
Condensate Tank No.2	2,500 BBL	80' dia x 30' H		400,000
Pig Receiver Assembly				20,000
Amine Plant No.1	49.5MMSCFD 1,050 psig	Package		2,000,000
Amine Plant No.2	49.5MMSCFD 1,050 psig	Package		2,000,000
Clycol Plant No.1	42.0MMSCFD	Package		1,400,000
Clycol Plant No.2	42.0MMSCFD	Package		1,400,000
Fuel Gas Package				80,000
Recovered Oil Pump	200 BPD/50 psi	1" x 2"	1,000	15,000
Load Out Pump No.1	20,000 BPD/150 psi	6" x 4"	4,000	35,000
Load Out Pump No.2	20,000 BPD/150 psi	6" x 4"	4,000	35,000
			TOTAL:	4,665,000

TABLE C2

ITEM	DESIGN	SIZE	DRY WEIGHT (lb)	COST
YEAR 1:				
Slug catcher/first stage Separator	87MMSCFD/7000BPD 1,050 psig @ 100°F	42" dia x 30' S/S(H)	32,000	160,000
2nd Stage Separator	6MMSCFD/6,000 BPD 450 psig @ 100°F	20" dia x 10' S/S	2,000	40,000
3rd Stage Separator	2MMSCFD/5,120 BPD 450 psig @ 100°F	20" dia x 10' S/S	2,000	40,000
API Separator	200 BPD			40,000
Condensate Tank No.1	40,000 BBL	90' dia x 42' H		500,000
Condensate Tank No.2	40,000 BBL	90' dia x 42' H		500,000
Pig Receiver Assembly				20,000
Amine Plant No.1	87.3MMSCFD 1,050 psig	Package		2,800,000
Clycol Plant	75.0MMSCFD 1,050 psig	Package		2,000,000
Fuel Gas Package				80,000
Recovered Oil Pump	200 BPD/50 psi	1" x 2"	1,000	15,000
Load Out Pump No.1	20,000 BPD/150 psi	6" x 4"	4,000	35,000
Load Out Pump No.2	20,000 BPD/150 psi	6" x 4"	4,000	35,000
			TOTAL:	6,265,000

APPENDIX D

ECONOMIC ANALYSIS
GAS TO VICTORIA & TASMANIA

VICTORIA

CASES 1 TO 4

JOB NO 3002
CLIENT AMOCO
CASE 1 VICTORIA

CAPITAL	$M	280.73
RATE GAS	$/GJ.	$1.17
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	10.00

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT

All Costs Aust. Dollars Millions.
(First Quarter 1989)

	DEVELOPMENT					PRODUCTION													
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	16.28						2.60			2.60						63.38
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	23.88														68.88
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.90	24.85	13.64														48.39
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	280.73
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						1.90	1.90	1.90	1.90	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	53.32
Offshore transport						1.21	1.21	1.21	1.21	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	77.74
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14,86	14.61	14.86	14.61	151.65
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$1.17				1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17
Natural Gas Revenue						35.10	35.10	35.10	35.10	35.10	35.10	35.10	35.10	28.08	21.06	14.04	10.53	7.02	361.53
Sales Liquid Throughput BBLS/Y x 1000						1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19270.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						39.27	39.27	39.27	39.27	39.27	39.27	39.27	39.27	31.50	23.52	15.75	11.76	7.98	404.67
TOTAL REVENUE						74.37	74.37	74.37	74.37	74.37	74.37	74.37	74.37	59.58	44.58	29.79	22.29	15	766.2

CASE 1 VICTORIA (Continued)

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						74.37	74.37	74.37	74.37	74.37	74.37	74.37	74.37	59.58	44.58	29.79	22.29	15.00
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-10.00	-2.90	-49.90	-103.01	-68.72	64.33	69.58	69.83	69.58	57.16	59.51	38.76	56.91	44.97	29.72	15.18	7.43	-14.61
Undeducted Expendature	0.00	-34.36	-47.69	-124.92	-291.75	-461.40	-508.25	-561.50	-629.33	-716.49	-843.94	-1004.07	-1235.59	-1508.71	-1873.59	-2360.15	-3001.57	-3832.49
Accum. Net Receipts	-10.00	-37.26	-97.59	-227.93	-360.47	-397.07	-438.67	-491.67	-559.75	-659.33	-784.43	-965.31	-1178.68	-1463.74	-1843.87	-2344.97	-2994.14	-3847.10
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						74.37	74.37	74.37	74.37	74.37	74.37	74.37	74.37	59.58	44.58	29.79	22.29	15.00
LESS																		
Total Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 190.43						36.18	36.18	36.18	36.18	36.18								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						33.15	33.40	33.65	33.40	23.58	59.51	59.76	59.51	44.97	29.72	15.18	7.43	0.39
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	12.93	13.03	13.12	13.03	9.20	23.21	23.31	23.21	17.54	11.59	5.92	2.90	0.15
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	74.37	74.37	74.37	74.37	74.37	74.37	74.37	74.37	59.58	44.58	29.79	22.29	15.00
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	12.93	13.03	13.12	13.03	9.20	23.21	23.31	23.21	17.54	11.59	5.92	2.90	0.15
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.90	-103.01	-68.72	51.40	56.55	56.71	56.55	47.96	36.30	15.45	33.70	27.43	18.13	9.26	4.53	-14.76
Cum Cash Flow	-10.00	-12.90	-62.80	-165.81	-234.53	-183.13	-126.57	-69.87	-13.31	34.65	70.95	86.41	120.11	147.54	165.67	174.93	179.46	164.70

IRR %	10.00	15.00	20.00
NPV $(Millions)	-0.02	-17.63	-22.83
IRR (CALC) %	10.00		

472212

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO	3002	
CLIENT	AMOCO	
CASE 1	VICTORIA	
CAPITAL	$M	280.73
RATE GAS	$/GJ.	$1.84
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	15.00

	DEVELOPMENT					PRODUCTION													
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	16.28						2.60			2.60						63.38
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	23.88														68.88
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.90	24.85	13.64														48.39
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	280.73
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						1.90	1.90	1.90	1.90	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	53.32
Offshore transport						1.21	1.21	1.21	1.21	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	77.74
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	151.65
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$1.84				1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84
Natural Gas Revenue						55.26	55.26	55.26	55.26	55.26	55.26	55.26	55.26	44.21	33.16	22.10	16.58	11.05	569.18
Sales Liquid Throughput BBLS/Y x 1000						1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19270.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						39.27	39.27	39.27	39.27	39.27	39.27	39.27	39.27	31.50	23.52	15.75	11.76	7.98	404.67
TOTAL REVENUE						94.53	94.53	94.53	94.53	94.53	94.53	94.53	94.53	75.708	56.676	37.854	28.338	19.032	973.848

CASE 1 VICTORIA (Continued)

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						94.53	94.53	94.53	94.53	94.53	94.53	94.53	94.53	75.71	56.68	37.85	28.34	19.03
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-10.00	-2.90	-49.90	-103.01	-68.72	84.49	89.74	89.99	89.74	77.32	79.67	58.92	77.07	61.10	41.82	23.24	13.48	-10.58
Undeducted Expendature	0.00	-34.36	-47.69	-124.92	-291.75	-461.40	-482.44	-502.66	-528.22	-561.26	-619.44	-690.90	-808.94	-936.79	-1120.88	-1381.21	-1738.19	-2207.64
Accum. Net Receipts	-10.00	-37.26	-97.59	-227.93	-360.47	-376.91	-392.70	-412.67	-438.48	-483.94	-539.77	-631.98	-731.87	-875.69	-1079.07	-1357.96	-1724.72	-2218.21
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						94.53	94.53	94.53	94.53	94.53	94.53	94.53	94.53	75.71	56.68	37.85	28.34	19.03
LESS																		
Total Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 190.43						36.18	36.18	36.18	36.18	36.18								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						53.31	53.56	53.81	53.56	43.74	79.67	79.92	79.67	61.10	41.82	23.24	13.48	4.42
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	20.79	20.89	20.99	20.89	17.06	31.07	31.17	31.07	23.83	16.31	9.07	5.26	1.72
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	94.53	94.53	94.53	94.53	94.53	94.53	94.53	94.53	75.71	56.68	37.85	28.34	19.03
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	20.79	20.89	20.99	20.89	17.06	31.07	31.17	31.07	23.83	16.31	9.07	5.26	1.72
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.90	-103.01	-68.72	63.70	68.85	69.00	68.85	60.26	48.60	27.75	46.00	37.27	25.51	14.18	8.22	-12.30
Cum Cash Flow	-10.00	-12.90	-62.80	-165.81	-234.53	-170.83	-101.98	-32.97	35.88	96.14	144.74	172.49	218.49	255.76	281.27	295.45	303.67	291.37

IRR %	10.00	15.00	20.00
NPV $(Millions)	32.31	-0.02	-12.83
IRR (CALC) %	15.00		

472214

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 1 VICTORIA
CAPITAL $M 280.73
RATE GAS $/GJ. $2.71
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 20.00

		DEVELOPMENT				PRODUCTION													
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	16.28						2.60			2.60						63.38
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	23.88														68.88
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.90	24.85	13.64														48.39
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	280.73
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						1.90	1.90	1.90	1.90	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	53.32
Offshore transport						1.21	1.21	1.21	1.21	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	77.74
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	151.65
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$2.71				2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71
Natural Gas Revenue						81.15	81.15	81.15	81.15	81.15	81.15	81.15	81.15	64.92	48.69	32.46	24.35	16.23	835.85
Sales Liquid Throughput BBLS/Y x 1000						1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19270.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						39.27	39.27	39.27	39.27	39.27	39.27	39.27	39.27	31.50	23.52	15.75	11.76	7.98	404.67
TOTAL REVENUE						120.42	120.42	120.42	120.42	120.42	120.42	120.42	120.42	96.42	72.21	48.21	36.105	24.21	1240.515

CASE 1 VICTORIA (Continued)

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						120.42	120.42	120.42	120.42	120.42	120.42	120.42	120.42	96.42	72.21	48.21	36.11	24.21
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-10.00	-2.90	-49.90	-103.01	-68.72	110.38	115.63	115.88	115.63	103.21	105.56	84.81	102.96	81.81	57.35	33.60	21.25	-5.40
Undeducted Expendature	0.00	-34.36	-47.69	-124.92	-291.75	-461.40	-449.31	-427.10	-398.37	-361.90	-331.13	-288.73	-261.02	-202.31	-154.24	-124.02	-115.74	-120.95
Accum. Net Receipts	-10.00	-37.26	-97.59	-227.93	-360.47	-351.02	-333.68	-311.22	-282.74	-258.69	-225.57	-203.92	-158.06	-120.50	-96.89	-90.42	-94.49	-126.35
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						120.42	120.42	120.42	120.42	120.42	120.42	120.42	120.42	96.42	72.21	48.21	36.11	24.21
LESS																		
Total Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 190.43						36.18	36.18	36.18	36.18	36.18								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						79.20	79.45	79.70	79.45	69.63	105.56	105.81	105.56	81.81	57.35	33.60	21.25	9.60
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	30.89	30.98	31.08	30.98	27.16	41.17	41.27	41.17	31.91	22.37	13.10	8.29	3.74
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	120.42	120.42	120.42	120.42	120.42	120.42	120.42	120.42	96.42	72.21	48.21	36.11	24.21
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	30.89	30.98	31.08	30.98	27.16	41.17	41.27	41.17	31.91	22.37	13.10	8.29	3.74
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.90	-103.01	-68.72	79.49	84.65	84.80	84.65	76.05	64.39	43.54	61.79	49.90	34.98	20.50	12.96	-9.14
Cum Cash Flow	-10.00	-12.90	-62.80	-165.81	-234.53	-155.04	-70.39	14.41	99.05	175.11	239.50	283.04	344.83	394.74	429.72	450.22	463.18	454.03

IRR %	10.00	15.00	20.00
NPV $(Millions)	73.83	22.60	0.01
IRR (CALC) %	20.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 2 VICTORIA

CAPITAL	$M	285.83
RATE GAS	$/GJ.	$1.24
RATE LIQUID	$/BBL.	$21.00
RIT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	10.00

		DEVELOPMENT				PRODUCTION													
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	20.95									2.60						65.45
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	26.84														71.84
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.80	24.43	14.23														48.46
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.80	107.26	72.27	5.00	0.00	0.00	0.00	0.00	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	285.83
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						1.90	1.90	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	59.68
Offshore transport						1.21	1.21	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	91.52
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						5.04	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	171.79
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$1.24				1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24
Natural Gas Revenue						37.14	37.14	37.14	37.14	37.14	37.14	37.14	37.14	29.71	22.28	14.86	11.14	7.43	382.54
Sales Liquid Throughput BBLS/Y x 1000						2000.00	1980.00	1980.00	1960.00	1940.00	1910.00	1890.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19840.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						42.00	41.58	41.58	41.16	40.74	40.11	39.69	39.27	31.50	23.52	15.75	11.76	7.98	416.64
TOTAL REVENUE						79.14	78.72	78.72	78.3	77.88	77.25	76.83	76.41	61.212	45.804	30.606	22.902	15.408	799.182

CASE 2   VICTORIA

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						79.14	78.72	78.72	78.30	77.88	77.25	76.83	76.41	61.21	45.80	30.61	22.90	15.41
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.80	107.26	72.27	5.00	0.00	0.00	0.00	0.00	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						5.04	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-10.00	-2.90	-49.80	-107.26	-72.27	69.10	73.93	64.11	63.44	63.27	62.39	41.22	58.95	46.60	30.94	16.00	8.04	-14.20
Undeducted Expendature	0.00	-34.36	-47.69	-124.79	-297.03	-472.70	-516.60	-566.62	-643.22	-742.12	-868.92	********	-1268.66	-1548.43	-1922.34	-2420.99	-3078.39	-3930.04
Accum. Net Receipts	-10.00	-37.26	-97.49	-232.05	-369.30	-403.60	-442.67	-502.51	-579.78	-678.85	-806.53	-991.14	-1209.71	-1501.83	-1891.40	-2404.99	-3070.35	-3944.25
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						79.14	78.72	78.72	78.30	77.88	77.25	76.83	76.41	61.21	45.80	30.61	22.90	15.41
LESS																		
Total Operating Costs						5.04	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 198.13						37.64	37.64	37.64	37.64	37.64								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						36.46	36.29	26.47	25.80	25.63	62.39	62.22	61.55	46.60	30.94	16.00	8.04	0.80
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	14.22	14.15	10.32	10.06	9.99	24.33	24.27	24.00	18.17	12.07	6.24	3.14	0.31
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	79.14	78.72	78.72	78.30	77.88	77.25	76.83	76.41	61.21	45.80	30.61	22.90	15.41
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	14.22	14.15	10.32	10.06	9.99	24.33	24.27	24.00	18.17	12.07	6.24	3.14	0.31
Total Capital	10.00	2.90	49.80	107.26	72.27	5.00	0.00	0.00	0.00	0.00	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.80	-107.26	-72.27	54.88	59.78	53.79	53.38	53.28	38.06	16.95	34.95	28.43	18.88	9.76	4.91	-14.51
Cum Cash Flow	-10.00	-12.90	-62.70	-169.96	-242.23	-187.35	-127.57	-73.78	-20.40	32.88	70.93	87.89	122.83	151.26	170.14	179.89	184.80	170.29

IRR %	10.00	15.00	20.00
NPV $(Millions)	0.02	-18.06	-23.35
IRR (CALC) %	10.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472218

JOB NO	3002	
CLIENT	AMOCO	
CASE 2	VICTORIA	
CAPITAL	$M	285.83
RATE GAS	$/GJ.	$1.93
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	15.00

			DEVELOPMENT									PRODUCTION							
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	20.95									2.60						65.45
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	26.84														71.84
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.80	24.43	14.23														48.46
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.80	107.26	72.27	5.00	0.00	0.00	0.00	0.00	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	285.83
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						1.90	1.90	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	59.68
Offshore transport						1.21	1.21	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	91.52
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						5.04	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	171.79
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$1.93				1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93
Natural Gas Revenue						57.81	57.81	57.81	57.81	57.81	57.81	57.81	57.81	46.25	34.69	23.12	17.34	11.56	595.44
Sales Liquid Throughput BBLS/Y x 1000						2000.00	1980.00	1980.00	1960.00	1940.00	1910.00	1890.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19840.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						42.00	41.58	41.58	41.16	40.74	40.11	39.69	39.27	31.50	23.52	15.75	11.76	7.98	416.64
TOTAL REVENUE						99.81	99.39	99.39	98.97	98.55	97.92	97.5	97.08	77.748	58.206	38.874	29.103	19.542	1012.083

CASE 2 VICTORIA

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						99.81	99.39	99.39	98.97	98.55	97.92	97.50	97.08	77.75	58.21	38.87	29.10	19.54
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.80	107.26	72.27	5.00	0.00	0.00	0.00	0.00	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						5.04	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-10.00	-2.90	-49.80	-107.26	-72.27	89.77	94.60	84.78	84.11	83.94	83.06	61.89	79.62	63.14	43.35	24.26	14.24	-10.07
Undeducted Expendature	0.00	-34.36	-47.69	-124.79	-297.03	-472.70	-490.15	-506.30	-539.55	-582.96	-638.74	-711.28	-831.21	-962.04	-1150.59	-1417.28	-1783.06	-2264.08
Accum. Net Receipts	-10.00	-37.26	-97.49	-232.05	-369.30	-382.93	-395.55	-421.52	-455.44	-499.02	-555.68	-649.39	-751.59	-898.90	-1107.25	-1393.01	-1768.81	-2274.15
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						99.81	99.39	99.39	98.97	98.55	97.92	97.50	97.08	77.75	58.21	38.87	29.10	19.54
LESS																		
Total Operating Costs						5.04	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 198.13						37.64	37.64	37.64	37.64	37.64								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						57.13	56.96	47.14	46.47	46.30	83.06	82.89	82.22	63.14	43.35	24.26	14.24	4.93
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	22.28	22.21	18.38	18.12	18.06	32.39	32.33	32.07	24.62	16.90	9.46	5.55	1.92
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	99.81	99.39	99.39	98.97	98.55	97.92	97.50	97.08	77.75	58.21	38.87	29.10	19.54
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	22.28	22.21	18.38	18.12	18.06	32.39	32.33	32.07	24.62	16.90	9.46	5.55	1.92
Total Capital	10.00	2.90	49.80	107.26	72.27	5.00	0.00	0.00	0.00	0.00	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.80	-107.26	-72.27	67.49	72.39	66.40	65.99	65.88	50.67	29.56	47.55	38.51	26.44	14.80	8.69	-11.99
Cum Cash Flow	-10.00	-12.90	-62.70	-169.96	-242.23	-174.74	-102.35	-35.95	30.03	95.92	146.59	176.15	223.70	262.22	288.66	303.46	312.15	300.16

IRR %	10.00	15.00	20.00
NPV $(Millions)	33.16	-0.00	-13.10
IRR (CALC) %	15.00		

472220

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO	3002	
CLIENT	AMOCO	
CASE 2	VICTORIA	
CAPITAL	$M	285.83
RATE GAS	$/GJ.	$2.81
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	20.00

		DEVELOPMENT				PRODUCTION													
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	20.95									2.60						65.45
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	26.84														71.84
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.80	24.43	14.23														48.46
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.80	107.26	72.27	5.00	0.00	0.00	0.00	0.00	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	285.83
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						1.90	1.90	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	59.68
Offshore transport						1.21	1.21	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	91.52
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						5.04	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	171.79
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$2.81				2.81	2.81	2.81	2.81	2.81	2.81	2.81	2.81	2.81	2.81	2.81	2.81	2.81	2.81
Natural Gas Revenue						84.24	84.24	84.24	84.24	84.24	84.24	84.24	84.24	67.39	50.54	33.70	25.27	16.85	867.67
Sales Liquid Throughput BBLS/Y x 1000						2000.00	1980.00	1980.00	1960.00	1940.00	1910.00	1890.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19840.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						42.00	41.58	41.58	41.16	40.74	40.11	39.69	39.27	31.50	23.52	15.75	11.76	7.98	416.64
TOTAL REVENUE						126.24	125.82	125.82	125.4	124.98	124.35	123.93	123.51	98.892	74.064	49.446	37.032	24.828	1284.312

CASE 2 VICTORIA

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						126.24	125.82	125.82	125.40	124.98	124.35	123.93	123.51	98.89	74.06	49.45	37.03	24.83
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.80	107.26	72.27	5.00	0.00	0.00	0.00	0.00	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						5.04	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-10.00	-2.90	-49.80	-107.26	-72.27	116.20	121.03	111.21	110.54	110.37	109.49	88.32	106.05	84.28	59.20	34.84	22.17	-4.78
Undeducted Expendature	0.00	-34.36	-47.69	-124.79	-297.03	-472.70	-456.32	-429.17	-406.99	-379.45	-344.42	-300.71	-271.86	-212.24	-163.79	-133.87	-126.76	-133.87
Accum. Net Receipts	-10.00	-37.26	-97.49	-232.05	-369.30	-356.50	-335.29	-317.96	-296.45	-269.08	-234.93	-212.39	-165.81	-127.96	-104.58	-99.03	-104.59	-138.66
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						126.24	125.82	125.82	125.40	124.98	124.35	123.93	123.51	98.89	74.06	49.45	37.03	24.83
LESS																		
Total Operating Costs						5.04	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 198.13						37.64	37.64	37.64	37.64	37.64								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						83.56	83.39	73.57	72.90	72.73	109.49	109.32	108.65	84.28	59.20	34.84	22.17	10.22
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	32.59	32.52	28.69	28.43	28.36	42.70	42.63	42.37	32.87	23.09	13.59	8.65	3.99
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	126.24	125.82	125.82	125.40	124.98	124.35	123.93	123.51	98.89	74.06	49.45	37.03	24.83
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	32.59	32.52	28.69	28.43	28.36	42.70	42.63	42.37	32.87	23.09	13.59	8.65	3.99
Total Capital	10.00	2.90	49.80	107.26	72.27	5.00	0.00	0.00	0.00	0.00	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.80	-107.26	-72.27	83.61	88.51	82.52	82.11	82.01	66.79	45.69	63.68	51.41	36.11	21.25	13.52	-8.77
Cum Cash Flow	-10.00	-12.90	-62.70	-169.96	-242.23	-158.62	-70.11	12.41	94.52	176.53	243.32	289.00	352.68	404.09	440.21	461.46	474.98	466.22

IRR %	10.00	15.00	20.00
NPV $(Millions)	75.55	23.08	0.01
IRR (CALC) %	20.00		

472222

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 3 VICTORIA
CAPITAL $M 287.91
RATE GAS $/GJ. $1.39
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 10.00

	DEVELOPMENT					PRODUCTION													
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	21.23							1.80		2.60						67.53
Offshore Installation				45.00	26.84														71.84
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					52.20														52.20
Insurance, Contingency			9.80	24.43	14.23														48.46
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.80	107.54	93.27	5.00	0.00	0.00	0.00	0.00	1.80	0.00	2.60	0.00	0.00	0.00	0.00	15.00	287.91
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	66.04
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	105.30
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	191.93
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$1.39				1.39	1.39	1.39	1.39	1.39	1.39	1.39	1.39	1.39	1.39	1.39	1.39	1.39	1.39
Natural Gas Revenue						41.64	41.64	41.64	41.64	41.64	41.64	41.64	41.64	33.31	24.98	16.66	12.49	8.33	428.89
Sales Liquid Throughput BBLS/Y x 1000						2120.00	2080.00	2080.00	2040.00	2000.00	1950.00	1910.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	20360.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						44.52	43.68	43.68	42.84	42.00	40.95	40.11	39.27	31.50	23.52	15.75	11.76	7.98	427.56
TOTAL REVENUE						86.16	85.32	85.32	84.48	83.64	82.59	81.75	80.91	64.812	48.504	32.406	24.252	16.308	856.452

CASE 3 VICTORIA

		DEVELOPMENT										PRODUCTION						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						86.16	85.32	85.32	84.48	83.64	82.59	81.75	80.91	64.81	48.50	32.41	24.25	16.31
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.80	107.54	93.27	5.00	0.00	0.00	0.00	0.00	1.80	0.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-10.00	-2.90	-49.80	-107.54	-93.27	66.05	70.46	70.71	69.62	69.03	65.93	67.14	63.45	50.20	33.64	17.80	9.39	-13.30
Undeducted Expendature	0.00	-34.36	-47.69	-124.79	-297.38	-500.04	-555.50	-620.85	-704.18	-812.24	-951.31	********	-1364.67	-1665.56	-2067.66	-2603.54	-3309.76	-4224.47
Accum. Net Receipts	-10.00	-37.26	-97.49	-232.33	-390.65	-433.99	-485.04	-550.14	-634.56	-743.21	-885.38	********	-1301.22	-1615.36	-2034.02	-2585.75	-3300.37	-4237.77
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						86.16	85.32	85.32	84.48	83.64	82.59	81.75	80.91	64.81	48.50	32.41	24.25	16.31
LESS																		
Total Operating Costs						15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 198.41						37.70	37.70	37.70	37.70	37.70								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						33.35	32.76	33.01	31.92	31.33	67.73	67.14	66.05	50.20	33.64	17.80	9.39	1.70
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	13.01	12.78	12.87	12.45	12.22	26.41	26.18	25.76	19.58	13.12	6.94	3.66	0.66
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	86.16	85.32	85.32	84.48	83.64	82.59	81.75	80.91	64.81	48.50	32.41	24.25	16.31
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	13.01	12.78	12.87	12.45	12.22	26.41	26.18	25.76	19.58	13.12	6.94	3.66	0.66
Total Capital	10.00	2.90	49.80	107.54	93.27	5.00	0.00	0.00	0.00	0.00	1.80	0.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.80	-107.54	-93.27	53.04	57.68	57.84	57.17	56.81	39.52	40.96	37.69	30.62	20.52	10.86	5.73	-13.96
Cum Cash Flow	-10.00	-12.90	-62.70	-170.24	-263.51	-210.47	-152.78	-94.95	-37.78	19.03	58.55	99.50	137.19	167.82	188.34	199.19	204.92	190.96

IRR %	10.00	15.00	20.00
NPV $(Millions)	-0.03	-19.72	-25.28
IRR (CALC) %	10.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 3 VICTORIA

CAPITAL	$M	287.91
RATE GAS	$/GJ.	$2.14
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	15.00

	DEVELOPMENT					PRODUCTION													
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	21.23							1.80		2.60						67.53
Offshore Installation				45.00	26.84														71.84
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					52.20														52.20
Insurance, Contingency			9.80	24.43	14.23														48.46
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.80	107.54	93.27	5.00	0.00	0.00	0.00	0.00	1.80	0.00	2.60	0.00	0.00	0.00	0.00	15.00	287.91
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	66.04
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	105.30
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	191.93
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$2.14				2.14	2.14	2.14	2.14	2.14	2.14	2.14	2.14	2.14	2.14	2.14	2.14	2.14	2.14
Natural Gas Revenue						64.20	64.20	64.20	64.20	64.20	64.20	64.20	64.20	51.36	38.52	25.68	19.26	12.84	661.26
Sales Liquid Throughput BBLS/Y x 1000						2120.00	2080.00	2080.00	2040.00	2000.00	1950.00	1910.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	20360.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						44.52	43.68	43.68	42.84	42.00	40.95	40.11	39.27	31.50	23.52	15.75	11.76	7.98	427.56
TOTAL REVENUE						108.72	107.88	107.88	107.04	106.2	105.15	104.31	103.47	82.86	62.04	41.43	31.02	20.82	1088.82

CASE 3 VICTORIA

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						108.72	107.88	107.88	107.04	106.20	105.15	104.31	103.47	82.86	62.04	41.43	31.02	20.82
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.80	107.54	93.27	5.00	0.00	0.00	0.00	0.00	1.80	0.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-10.00	-2.90	-49.80	-107.54	-93.27	88.61	93.02	93.27	92.18	91.59	88.49	89.70	86.01	68.25	47.18	26.82	16.16	-8.79
Undeducted Expendature	0.00	-34.36	-47.69	-124.79	-297.38	-500.04	-526.63	-555.02	-591.03	-638.53	-700.09	-782.84	-887.22	-1025.56	-1225.35	-1508.06	-1895.99	-2406.18
Accum. Net Receipts	-10.00	-37.26	-97.49	-232.33	-390.65	-411.43	-433.61	-461.75	-498.85	-546.94	-611.60	-693.14	-801.21	-957.31	-1178.17	-1481.24	-1879.83	-2414.97
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						108.72	107.88	107.88	107.04	106.20	105.15	104.31	103.47	82.86	62.04	41.43	31.02	20.82
LESS																		
Total Operating Costs						15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 198.41						37.70	37.70	37.70	37.70	37.70								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						55.91	55.32	55.57	54.48	53.89	90.29	89.70	88.61	68.25	47.18	26.82	16.16	6.21
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	21.81	21.58	21.67	21.25	21.02	35.21	34.98	34.56	26.62	18.40	10.46	6.30	2.42
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	108.72	107.88	107.88	107.04	106.20	105.15	104.31	103.47	82.86	62.04	41.43	31.02	20.82
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	21.81	21.58	21.67	21.25	21.02	35.21	34.98	34.56	26.62	18.40	10.46	6.30	2.42
Total Capital	10.00	2.90	49.80	107.54	93.27	5.00	0.00	0.00	0.00	0.00	1.80	0.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.80	-107.54	-93.27	66.80	71.44	71.60	70.93	70.57	53.28	54.72	51.45	41.63	28.78	16.36	9.86	-11.21
Cum Cash Flow	-10.00	-12.90	-62.70	-170.24	-263.51	-196.71	-125.26	-53.66	17.27	87.84	141.12	195.83	247.29	288.92	317.70	334.06	343.92	332.70

IRR %	10.00	15.00	20.00
NPV $(Millions)	36.15	-0.02	-14.09
IRR (CALC) %	15.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472226

JOB NO	3002	
CLIENT	AMOCO	
CASE 3	VICTORIA	
CAPITAL	$M	287.91
RATE GAS	$/GJ.	$3.09
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	20.00

		DEVELOPMENT				PRODUCTION													
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	21.23							1.80		2.60						67.53
Offshore Installation				45.00	26.84														71.84
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					52.20														52.20
Insurance, Contingency			9.80	24.43	14.23														48.46
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.80	107.54	93.27	5.00	0.00	0.00	0.00	0.00	1.80	0.00	2.60	0.00	0.00	0.00	0.00	15.00	287.91
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	66.04
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	105.30
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	191.93
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$3.09				3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09
Natural Gas Revenue						92.61	92.61	92.61	92.61	92.61	92.61	92.61	92.61	74.09	55.57	37.04	27.78	18.52	953.88
Sales Liquid Throughput BBLS/Y x 1000						2120.00	2080.00	2080.00	2040.00	2000.00	1950.00	1910.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	20360.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						44.52	43.68	43.68	42.84	42.00	40.95	40.11	39.27	31.50	23.52	15.75	11.76	7.98	427.56
TOTAL REVENUE						137.13	136.29	136.29	135.45	134.61	133.56	132.72	131.88	105.588	79.086	52.794	39.543	26.502	1381.443

CASE 3 VICTORIA

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						137.13	136.29	136.29	135.45	134.61	133.56	132.72	131.88	105.59	79.09	52.79	39.54	26.50
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.80	107.54	93.27	5.00	0.00	0.00	0.00	0.00	1.80	0.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-10.00	-2.90	-49.80	-107.54	-93.27	117.02	121.43	121.68	120.59	120.00	116.90	118.11	114.42	90.98	64.23	38.18	24.68	-3.11
Undeducted Expendature	0.00	-34.36	-47.69	-124.79	-297.38	-500.04	-490.26	-472.10	-448.54	-419.78	-383.72	-341.53	-285.97	-219.59	-164.62	-128.50	-115.61	-116.38
Accum. Net Receipts	-10.00	-37.26	-97.49	-232.33	-390.65	-383.02	-368.83	-350.42	-327.95	-299.78	-266.82	-223.42	-171.55	-128.61	-100.39	-90.32	-90.93	-119.49
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						137.13	136.29	136.29	135.45	134.61	133.56	132.72	131.88	105.59	79.09	52.79	39.54	26.50
LESS																		
Total Operating Costs						15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 198.41						37.70	37.70	37.70	37.70	37.70								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						84.32	83.73	83.98	82.89	82.30	118.70	118.11	117.02	90.98	64.23	38.18	24.68	11.89
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	32.89	32.66	32.75	32.33	32.10	46.29	46.06	45.64	35.48	25.05	14.89	9.63	4.64
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	137.13	136.29	136.29	135.45	134.61	133.56	132.72	131.88	105.59	79.09	52.79	39.54	26.50
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	32.89	32.66	32.75	32.33	32.10	46.29	46.06	45.64	35.48	25.05	14.89	9.63	4.64
Total Capital	10.00	2.90	49.80	107.54	93.27	5.00	0.00	0.00	0.00	0.00	1.80	0.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.80	-107.54	-93.27	84.13	88.77	88.93	88.26	87.90	70.61	72.05	68.78	55.50	39.18	23.29	15.06	-7.75
Cum Cash Flow	-10.00	-12.90	-62.70	-170.24	-263.51	-179.38	-90.60	-1.67	86.59	174.49	245.10	317.14	385.93	441.42	480.60	503.89	518.95	511.20

IRR %	10.00	15.00	20.00
NPV $(Millions)	81.72	24.80	0.00
IRR (CALC) %	20.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO	3002	
CLIENT	AMOCO	
CASE 4	VICTORIA	
CAPITAL	$M	274.98
RATE GAS	$/GJ.	$1.04
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	10.00

		DEVELOPMENT				PRODUCTION						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	TOTAL
CAPITAL INVESTMENT												
Exploration Well	10.0											10.00
Pre-Engr., Investigation		1.00										1.00
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	26.63					2.60	7.40		78.53
Offshore Installation				45.00	23.88							68.88
Onshore Plant, Marine Base				16.88								16.88
Development Drilling					31.20							31.20
Insurance, Contingency			9.90	24.85	13.74							48.49
Working Capital						5.00					-5.00	0.00
Platform Removal											20.00	20.00
Total Capital	10.00	2.90	49.90	113.36	68.82	5.00	0.00	0.00	2.60	7.40	15.00	274.98
OPERATING COSTS												
Start Up						0.50						0.50
Offshore facility						1.90	1.90	1.90	5.08	5.08	5.08	20.94
Offshore transport						1.21	1.21	1.21	8.10	8.10	8.10	27.93
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	3.48
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	5.10
Well Workover							0.25		0.25		0.25	0.75
TOTAL COSTS						5.04	4.79	4.54	14.86	14.61	14.86	58.70
REVENUE												
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	180.00
Gas Selling Price $/GJ		$1.04				1.04	1.04	1.04	1.04	1.04	1.04	1.04
Natural Gas Revenue						31.32	31.32	31.32	31.32	31.32	31.32	187.92
Sales Liquid Throughput BBLS/Y x 1000						3340.00	3340.00	3300.00	3220.00	3220.00	3220.00	19640.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						70.14	70.14	69.30	67.62	67.62	67.62	412.44
TOTAL REVENUE						101.46	101.46	100.62	98.94	98.94	98.94	600.36

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO	3002	
CLIENT	AMOCO	
CASE 4	VICTORIA	
CAPITAL	$M	274.98
RATE GAS	$/GJ.	$1.84
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	15.00

	DEVELOPMENT					PRODUCTION						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	TOTAL
CAPITAL INVESTMENT												
Exploration Well	10.0											10.00
Pre-Engr., Investigation		1.00										1.00
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	26.63					2.60	7.40		78.53
Offshore Installation				45.00	23.88							68.88
Onshore Plant, Marine Base				16.88								16.88
Development Drilling					31.20							31.20
Insurance, Contingency			9.90	24.85	13.74							48.49
Working Capital						5.00					-5.00	0.00
Platform Removal											20.00	20.00
Total Capital	10.00	2.90	49.90	113.36	68.82	5.00	0.00	0.00	2.60	7.40	15.00	274.98
OPERATING COSTS												
Start Up						0.50						0.50
Offshore facility						1.90	1.90	1.90	5.08	5.08	5.08	20.94
Offshore transport						1.21	1.21	1.21	8.10	8.10	8.10	27.93
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	3.48
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	5.10
Well Workover							0.25		0.25		0.25	0.75
TOTAL COSTS						5.04	4.79	4.54	14.86	14.61	14.86	58.70
REVENUE												
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	180.00
Gas Selling Price $/GJ		$1.84				1.84	1.84	1.84	1.84	1.84	1.84	1.84
Natural Gas Revenue						55.11	55.11	55.11	55.11	55.11	55.11	330.66
Sales Liquid Throughput BBLS/Y x 1000						3340.00	3340.00	3300.00	3220.00	3220.00	3220.00	19640.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						70.14	70.14	69.30	67.62	67.62	67.62	412.44
TOTAL REVENUE						125.25	125.25	124.41	122.73	122.73	122.73	743.1

472230

			DEVEL								
YEAR	-5	1	2	3	4	1	2	3	4	5	6
RESOURCE RENT TAX											
Receipts						125.25	125.25	124.41	122.73	122.73	122.73
LESS											
Expenditure											
Capital Costs	10.00	2.90	49.90	113.36	68.82	5.00	0.00	0.00	2.60	7.40	15.00
Operating Costs						5.04	4.79	4.54	14.86	14.61	14.86
Net Annual Receipts	-10.00	-2.90	-49.90	-113.36	-68.82	115.21	120.46	119.87	105.27	100.72	92.87
Undeducted Expendature	0.00	-34.36	-47.69	-124.92	-305.00	-478.49	-464.99	-441.00	-411.05	-391.40	-372.07
Accum. Net Receipts	-10.00	-37.26	-97.59	-238.28	-373.82	-363.28	-344.53	-321.13	-305.78	-290.68	-279.20
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE											
Gas and Liquid Revenue						125.25	125.25	124.41	122.73	122.73	122.73
LESS											
Total Operating Costs						5.04	4.79	4.54	14.86	14.61	14.86
Depreciation on : 200.88						38.17	38.17	38.17	38.17	38.17	
RRT						0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						82.04	82.29	81.70	69.70	69.95	107.87
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	32.00	32.09	31.86	27.18	27.28	42.07
CASH FLOW											
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	125.25	125.25	124.41	122.73	122.73	122.73
LESS											
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	4.54	14.86	14.61	14.86
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	32.00	32.09	31.86	27.18	27.28	42.07
Total Capital	10.00	2.90	49.90	113.36	68.82	5.00	0.00	0.00	2.60	7.40	15.00
Cash Flow	-10.00	-2.90	-49.90	-113.36	-68.82	83.21	88.37	88.01	78.09	73.44	50.80
Cum Cash Flow	-10.00	-12.90	-62.80	-176.16	-244.98	-161.77	-73.40	14.61	92.69	166.13	216.93

IRR %	10.00	15.00	20.00
NPV $(Millions)	26.81	-0.00	-11.41
IRR (CALC) %	15.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 4 VICTORIA
CAPITAL $M 274.98
RATE GAS $/GJ. $3.00
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 20.00

	DEVELOPMENT					PRODUCTION						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	TOTAL
CAPITAL INVESTMENT												
Exploration Well	10.0											10.00
Pre-Engr., Investigation		1.00										1.00
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	26.63					2.60	7.40		78.53
Offshore Installation				45.00	23.88							68.88
Onshore Plant, Marine Base				16.88								16.88
Development Drilling					31.20							31.20
Insurance, Contingency			9.90	24.85	13.74							48.49
Working Capital						5.00					-5.00	0.00
Platform Removal											20.00	20.00
Total Capital	10.00	2.90	49.90	113.36	68.82	5.00	0.00	0.00	2.60	7.40	15.00	274.98
OPERATING COSTS												
Start Up						0.50						0.50
Offshore facility						1.90	1.90	1.90	5.08	5.08	5.08	20.94
Offshore transport						1.21	1.21	1.21	8.10	8.10	8.10	27.93
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	3.48
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	5.10
Well Workover							0.25		0.25		0.25	0.75
TOTAL COSTS						5.04	4.79	4.54	14.86	14.61	14.86	58.70
REVENUE												
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	180.00
Gas Selling Price $/GJ		$3.00				3.00	3.00	3.00	3.00	3.00	3.00	3.00
Natural Gas Revenue						89.88	89.88	89.88	89.88	89.88	89.88	539.28
Sales Liquid Throughput BBLS/Y x 1000						3340.00	3340.00	3300.00	3220.00	3220.00	3220.00	19640.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						70.14	70.14	69.30	67.62	67.62	67.62	412.44
TOTAL REVENUE						160.02	160.02	159.18	157.5	157.5	157.5	951.72

CASE [illegible]

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YEAR	-5	1	2	3	4	1	2	3	4	5	6
RESOURCE RENT TAX											
Receipts						160.02	160.02	159.18	157.50	157.50	157.50
LESS											
Expenditure											
Capital Costs	10.00	2.90	49.90	113.36	68.82	5.00	0.00	0.00	2.60	7.40	15.00
Operating Costs						5.04	4.79	4.54	14.86	14.61	14.86
Net Annual Receipts	-10.00	-2.90	-49.90	-113.36	-68.82	149.98	155.23	154.64	140.04	135.49	127.64
Undeducted Expendature	0.00	-34.36	-47.69	-124.92	-305.00	-478.49	-420.49	-339.53	-236.66	-123.67	0.00
Accum. Net Receipts	-10.00	-37.26	-97.59	-238.28	-373.82	-328.51	-265.26	-184.89	-96.62	11.82	127.64
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.73	51.06
TAX SCHEDULE											
Gas and Liquid Revenue						160.02	160.02	159.18	157.50	157.50	157.50
LESS											
Total Operating Costs						5.04	4.79	4.54	14.86	14.61	14.86
Depreciation on : 200.88						38.17	38.17	38.17	38.17	38.17	
RRT						0.00	0.00	0.00	0.00	4.73	51.06
Taxable Income						116.81	117.06	116.47	104.47	100.00	91.58
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	45.56	45.65	45.42	40.74	39.00	35.72
CASH FLOW											
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	160.02	160.02	159.18	157.50	157.50	157.50
LESS											
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	4.54	14.86	14.61	14.86
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.73	51.06
Tax	0.00	0.00	0.00	0.00	0.00	45.56	45.65	45.42	40.74	39.00	35.72
Total Capital	10.00	2.90	49.90	113.36	68.82	5.00	0.00	0.00	2.60	7.40	15.00
Cash Flow	-10.00	-2.90	-49.90	-113.36	-68.82	104.42	109.58	109.22	99.30	91.76	40.87
Cum Cash Flow	-10.00	-12.90	-62.80	-176.16	-244.98	-140.56	-30.98	78.23	177.53	269.29	310.16

IRR %	10.00	15.00	20.00
NPV $(Millions)	57.77	18.58	0.01
IRR (CALC) %	20.00		

TASMANIA

CASES 1 TO 4

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472234

JOB NO 3002
CLIENT AMOCO
CASE 1 TASMANIA
CAPITAL $M 258.19
RATE GAS $/GJ. $1.78
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 10.00

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.13												3.40		
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.29	24.40	8.94													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	5.08	5.08	5.08
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	8.10	8.10	8.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$1.78				$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78
Natural Gas Revenue						21.37	24.93	26.72	26.72	28.50	28.50	30.28	30.28	30.28	30.28	30.28	30.28	30.28
Sales Liquid Throughput BBLS/Y x 1000						750.00	870.00	940.00	940.00	1000.00	1000.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						15.75	18.27	19.74	19.74	21.00	21.00	22.26	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						37.122	43.204	46.455	46.455	49.496	49.496	52.537	52.537	52.537	52.537	52.537	52.537	52.537

47223

CASE 1 TASMANIA (Continued)

												PRODUCTION		
YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform						2.60	2.60							66.63
and Pipeline Fabrication														0.00
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														43.63
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40	258.19
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	74.88
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	101.20
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	207.85
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$1.78				1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78
Natural Gas Revenue						30.28	30.28	30.28	24.93	19.59	16.03	12.47	10.69	543.20
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19040.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	399.84
TOTAL REVENUE						52.537	52.537	52.537	43.204	34.081	27.789	21.707	18.666	943.045

CASE 1 TASMANIA (Continued)

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						37.12	43.20	46.46	46.46	49.50	49.50	52.54	52.54	52.54	52.54	52.54	52.54	52.54
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Net Annual Receipts	-10.00	-2.90	-50.29	-100.72	-43.68	27.54	38.47	41.98	41.73	45.02	44.77	48.06	47.81	48.06	47.81	23.59	37.74	37.99
Undeducted Expendature	0.00	-34.36	-47.69	-125.42	-289.46	-426.41	-510.56	-604.27	-719.73	-867.85	-1053.23	-1290.83	-1590.75	-1974.97	-2466.45	-3095.86	-3932.51	-4985.31
Accum. Net Receipts	-10.00	-37.26	-97.98	-226.14	-333.14	-398.87	-472.08	-562.29	-678.01	-822.83	-1008.46	-1242.77	-1542.94	-1926.91	-2418.64	-3072.27	-3894.77	-4947.32
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						37.12	43.20	46.46	46.46	49.50	49.50	52.54	52.54	52.54	52.54	52.54	52.54	52.54
LESS																		
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Depreciation on : 183.49						34.86	34.86	34.86	34.86	34.86								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						-2.72	3.61	7.11	6.86	10.15	44.77	48.06	47.81	48.06	47.81	37.99	37.74	37.99
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	0.00	1.41	2.77	2.68	3.96	17.46	18.74	18.64	18.74	18.64	14.81	14.72	14.81
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	37.12	43.20	46.46	46.46	49.50	49.50	52.54	52.54	52.54	52.54	52.54	52.54	52.54
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	0.00	1.41	2.77	2.68	3.96	17.46	18.74	18.64	18.74	18.64	14.81	14.72	14.81
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Cash Flow	-10.00	-2.90	-50.29	-100.72	-43.68	27.54	37.07	39.20	39.05	41.06	27.31	29.31	29.16	29.31	29.16	8.77	23.02	23.17
Cum Cash Flow	-10.00	-12.90	-63.19	-163.91	-207.59	-180.05	-142.98	-103.78	-64.73	-23.68	3.63	32.95	62.11	91.42	120.59	129.36	152.38	175.55

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472237

JOB NO	3002	
CLIENT	AMOCO	
CASE 1	TASMANIA	
CAPITAL	$M	258.19
RATE GAS	$/GJ.	$3.03
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	15.00

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.13												3.40		
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.29	24.40	8.94													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	5.08	5.08	5.08
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	8.10	8.10	8.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$3.03				$3.03	$3.03	$3.03	$3.03	$3.03	$3.03	$3.03	$3.03	$3.03	$3.03	$3.03	$3.03	$3.03
Natural Gas Revenue						36.41	42.48	45.51	45.51	48.54	48.54	51.58	51.58	51.58	51.58	51.58	51.58	51.58
Sales Liquid Throughput BBLS/Y x 1000						750.00	870.00	940.00	940.00	1000.00	1000.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						15.75	18.27	19.74	19.74	21.00	21.00	22.26	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						52.158	60.746	65.25	65.25	69.544	69.544	73.838	73.838	73.838	73.838	73.838	73.838	73.838

CASE 1 TASMANIA (Continued)

							PRODUCTION	
YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	52.54	52.54	52.54	43.20	34.08	27.79	21.71	18.67
LESS								
Expenditure								
Capital Costs	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	35.14	24.39	37.74	28.65	19.28	13.24	6.91	-11.28
Undeducted Expendature	-6332.57	-8060.72	**********	-13118.42	-16754.90	-21421.59	-27402.69	-35066.60
Accum. Net Receipts	-6297.43	-8036.33	**********	-13089.76	-16735.62	-21408.35	-27395.78	-35077.88
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	52.54	52.54	52.54	43.20	34.08	27.79	21.71	18.67
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.49								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	37.74	37.99	37.74	28.65	19.28	13.24	6.91	4.12
Tax % 39.00	14.72	14.81	14.72	11.18	7.52	5.16	2.69	1.61
CASH FLOW								
Gas and Liquid Revenue	52.54	52.54	52.54	43.20	34.08	27.79	21.71	18.67
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	14.72	14.81	14.72	11.18	7.52	5.16	2.69	1.61
Total Capital	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Cash Flow	20.42	9.57	23.02	17.48	11.76	8.08	4.21	-12.89
Cum Cash Flow	195.97	205.54	228.56	246.04	257.80	265.88	270.09	257.20

IRR %	10.00	15.00	20.00
NPV $(Millions)	-0.01	-20.87	-25.79
IRR (CALC) %	10.00		

CASE 1 TASMANIA (Continued)

												PRODUCTION		
YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform						2.60	2.60							66.63
and Pipeline Fabrication														0.00
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														43.63
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40	258.19
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	74.88
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	101.20
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	207.85
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$3.03				3.03	3.03	3.03	3.03	3.03	3.03	3.03	3.03	3.03
Natural Gas Revenue						51.58	51.58	51.58	42.48	33.37	27.31	21.24	18.20	925.37
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19040.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	399.84
TOTAL REVENUE						73.838	73.838	73.838	60.746	47.864	39.066	30.478	26.184	1325.21

CASE 1 TASMANIA (Continued)

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						52.16	60.75	65.25	65.25	69.54	69.54	73.84	73.84	73.84	73.84	73.84	73.84	73.84
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Net Annual Receipts	-10.00	-2.90	-50.29	-100.72	-43.68	42.58	56.02	60.77	60.52	65.06	64.81	69.36	69.11	69.36	69.11	44.89	59.04	59.29
Undeducted Expendature	0.00	-34.36	-47.69	-125.42	-289.46	-426.41	-491.31	-557.18	-635.40	-735.85	-858.60	-1016.05	-1211.77	-1462.61	-1783.36	-2194.24	-2751.17	-3445.93
Accum. Net Receipts	-10.00	-37.26	-97.98	-226.14	-333.14	-383.84	-435.30	-496.41	-574.88	-670.79	-793.79	-946.69	-1142.66	-1393.25	-1714.25	-2149.35	-2692.13	-3386.64
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						52.16	60.75	65.25	65.25	69.54	69.54	73.84	73.84	73.84	73.84	73.84	73.84	73.84
LESS																		
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Depreciation on : 183.49						34.86	34.86	34.86	34.86	34.86								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						12.31	21.15	25.91	25.66	30.20	64.81	69.36	69.11	69.36	69.11	59.29	59.04	59.29
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	4.80	8.25	10.10	10.01	11.78	25.28	27.05	26.95	27.05	26.95	23.12	23.02	23.12
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	52.16	60.75	65.25	65.25	69.54	69.54	73.84	73.84	73.84	73.84	73.84	73.84	73.84
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	4.80	8.25	10.10	10.01	11.78	25.28	27.05	26.95	27.05	26.95	23.12	23.02	23.12
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Cash Flow	-10.00	-2.90	-50.29	-100.72	-43.68	37.78	47.77	50.67	50.51	53.29	39.54	42.31	42.16	42.31	42.16	21.77	36.01	36.17
Cum Cash Flow	-10.00	-12.90	-63.19	-163.91	-207.59	-169.81	-122.05	-71.38	-20.87	32.42	71.95	114.26	156.42	198.73	240.88	262.65	298.66	334.83

CASE 1 TASMANIA (Continued)

							PRODUCTION	
YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	73.84	73.84	73.84	60.75	47.86	39.07	30.48	26.18
LESS								
Expenditure								
Capital Costs	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	56.44	45.69	59.04	46.20	33.06	24.52	15.68	-3.77
Undeducted Expendature	-4334.90	-5476.43	-6951.35	-8822.16	-11233.23	-14336.21	-18318.97	-23428.22
Accum. Net Receipts	-4278.46	-5430.74	-6892.31	-8775.96	-11200.17	-14311.70	-18303.30	-23431.99
RIT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	73.84	73.84	73.84	60.75	47.86	39.07	30.48	26.18
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.49								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	59.04	59.29	59.04	46.20	33.06	24.52	15.68	11.63
Tax % 39.00	23.02	23.12	23.02	18.02	12.89	9.56	6.11	4.54
CASH FLOW								
Gas and Liquid Revenue	73.84	73.84	73.84	60.75	47.86	39.07	30.48	26.18
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RIT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	23.02	23.12	23.02	18.02	12.89	9.56	6.11	4.54
Total Capital	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Cash Flow	33.41	22.57	36.01	28.18	20.17	14.95	9.56	-8.30
Cum Cash Flow	368.24	390.81	426.82	455.00	475.17	490.12	499.69	491.38

IRR %	10.00	15.00	20.00
NPV $(Millions)	42.54	-0.02	-14.81
IRR (CALC) %	15.00		

472242

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO	3002	
CLIENT	AMOCO	
CASE 1	TASMANIA	
CAPITAL	$M	258.19
RATE GAS	$/GJ.	$4.75
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	20.00

			DEVELOPMENT									PRODUCTION						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.13												3.40		
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.29	24.40	8.94													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	5.08	5.08	5.08
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	8.10	8.10	8.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$4.75				$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75
Natural Gas Revenue						57.05	66.56	71.31	71.31	76.06	76.06	80.82	80.82	80.82	80.82	80.82	80.82	80.82
Sales Liquid Throughput BBLS/Y x 1000						750.00	870.00	940.00	940.00	1000.00	1000.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						15.75	18.27	19.74	19.74	21.00	21.00	22.26	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						72.798	84.826	91.05	91.05	97.064	97.064	103.078	103.078	103.078	103.078	103.078	103.078	103.078

CASE 1 TASMANIA (Continued)

											PRODUCTION			
YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform						2.60	2.60							66.63
and Pipeline Fabrication														0.00
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														43.63
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40	258.19
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	74.88
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	101.20
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	207.85
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$4.75				4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75
Natural Gas Revenue						80.82	80.82	80.82	66.56	52.29	42.79	33.28	28.52	1449.97
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19040.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	399.84
TOTAL REVENUE						103.078	103.078	103.078	84.826	66.784	54.546	42.518	36.504	1849.81

CASE 1 TASMANIA (Continued)

		DEVELOPMENT				PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						72.80	84.83	91.05	91.05	97.06	97.06	103.08	103.08	103.08	103.08	103.08	103.08	103.08
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Net Annual Receipts	-10.00	-2.90	-50.29	-100.72	-43.68	63.22	80.10	86.57	86.32	92.58	92.33	98.60	98.35	98.60	98.35	74.13	88.28	88.53
Undeducted Expendature	0.00	-34.36	-47.69	-125.42	-289.46	-426.41	-464.89	-492.54	-519.64	-554.65	-591.44	-638.86	-691.54	-759.28	-845.68	-956.58	-1129.54	-1332.81
Accum. Net Receipts	-10.00	-37.26	-97.98	-226.14	-333.14	-363.20	-384.80	-405.97	-433.32	-462.07	-499.11	-540.26	-593.19	-660.68	-747.33	-882.45	-1041.26	-1244.28
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						72.80	84.83	91.05	91.05	97.06	97.06	103.08	103.08	103.08	103.08	103.08	103.08	103.08
LESS																		
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Depreciation on : 183.49						34.86	34.86	34.86	34.86	34.86								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						32.95	45.23	51.71	51.46	57.72	92.33	98.60	98.35	98.60	98.35	88.53	88.28	88.53
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	12.85	17.64	20.17	20.07	22.51	36.01	38.45	38.36	38.45	38.36	34.53	34.43	34.53
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	72.80	84.83	91.05	91.05	97.06	97.06	103.08	103.08	103.08	103.08	103.08	103.08	103.08
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	12.85	17.64	20.17	20.07	22.51	36.01	38.45	38.36	38.45	38.36	34.53	34.43	34.53
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Cash Flow	-10.00	-2.90	-50.29	-100.72	-43.68	50.37	62.46	66.40	66.25	70.07	56.32	60.14	59.99	60.14	59.99	39.60	53.85	54.00
Cum Cash Flow	-10.00	-12.90	-63.19	-163.91	-207.59	-157.22	-94.77	-28.36	37.89	107.96	164.28	224.43	284.42	344.57	404.56	444.16	498.01	552.01

CASE 1 TASMANIA (Continued)

							PRODUCTION	
YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	103.08	103.08	103.08	84.83	66.78	54.55	42.52	36.50
LESS								
Expenditure								
Capital Costs	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	85.68	74.93	88.28	70.28	51.98	40.00	27.72	6.55
Undeducted Expendature	-1592.68	-1928.97	-2373.17	-2924.66	-3653.61	-4610.08	-5849.71	-7452.15
Accum. Net Receipts	-1507.00	-1854.04	-2284.89	-2854.38	-3601.63	-4570.09	-5821.99	-7445.60
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	103.08	103.08	103.08	84.83	66.78	54.55	42.52	36.50
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.49								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	88.28	88.53	88.28	70.28	51.98	40.00	27.72	21.95
Tax % 39.00	34.43	34.53	34.43	27.41	20.27	15.60	10.81	8.56
CASH FLOW								
Gas and Liquid Revenue	103.08	103.08	103.08	84.83	66.78	54.55	42.52	36.50
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	34.43	34.53	34.43	27.41	20.27	15.60	10.81	8.56
Total Capital	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Cash Flow	51.25	40.40	53.85	42.87	31.71	24.40	16.91	-2.01
Cum Cash Flow	603.26	643.66	697.51	740.38	772.09	796.49	813.40	811.39

IRR %	10.00	15.00	20.00
NPV $(Millions)	100.38	28.25	0.02
IRR (CALC) %	20.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472246

JOB NO	3002	
CLIENT	AMOCO	
CASE 2	TASMANIA	
CAPITAL	$M	255.58
RATE GAS	$/GJ.	$1.62
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	10.00

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.68														
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.06	24.08	8.73													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.06	100.95	43.47	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$1.62				1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62
Natural Gas Revenue						19.46	22.71	24.33	24.33	25.95	25.95	27.57	27.57	27.57	27.57	27.57	27.57	27.57
Sales Liquid Throughput BBLS/Y x 1000						880.00	980.00	1040.00	1020.00	1060.00	1040.00	1080.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						18.48	20.58	21.84	21.42	22.26	21.84	22.68	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						37.944	43.288	46.17	45.75	48.212	47.792	50.254	49.834	49.834	49.834	49.834	49.834	49.834

472247

CASE 2 TASMANIA (Continued)

												PRODUCTION		
YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform						1.80	1.80	2.60						64.78
and Pipeline Fabrication														0.00
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														42.87
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	1.80	12.80	2.60	0.00	0.00	0.00	0.00	15.40	255.58
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	65.34
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	80.53
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	177.64
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$1.62				1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62
Natural Gas Revenue						27.57	27.57	27.57	22.71	17.84	14.60	11.35	9.73	494.71
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19580.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	411.18
TOTAL REVENUE						49.834	49.834	49.834	40.978	32.332	26.358	20.594	17.712	905.89

CASE 2 TASMANIA (Continued)

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						37.94	43.29	46.17	45.75	48.21	47.79	50.25	49.83	49.83	49.83	49.83	49.83	49.83
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.06	100.95	43.47	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.00	0.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
Net Annual Receipts	-10.00	-2.90	-50.06	-100.95	-43.47	28.36	38.56	41.69	41.02	43.73	43.06	45.77	45.10	45.35	45.10	34.35	45.10	45.35
Undeducted Expendature	0.00	-34.36	-47.69	-125.12	-289.37	-426.04	-509.03	-602.20	-717.45	-865.83	-1052.29	-1291.81	-1594.93	-1983.77	-2481.18	-3118.17	-3947.29	-4994.79
Accum. Net Receipts	-10.00	-37.26	-97.75	-226.07	-332.84	-397.68	-470.47	-560.51	-676.43	-822.10	-1009.23	-1246.04	-1549.82	-1938.42	-2436.07	-3083.82	-3902.18	-4949.44
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						37.94	43.29	46.17	45.75	48.21	47.79	50.25	49.83	49.83	49.83	49.83	49.83	49.83
LESS																		
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
Depreciation on : 183.28						34.82	34.82	34.82	34.82	34.82								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						-1.86	3.73	6.87	6.20	8.91	43.06	45.77	45.10	45.35	45.10	45.35	45.10	45.35
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	0.00	1.46	2.68	2.42	3.47	16.79	17.85	17.59	17.69	17.59	17.69	17.59	17.69
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	37.94	43.29	46.17	45.75	48.21	47.79	50.25	49.83	49.83	49.83	49.83	49.83	49.83
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	0.00	1.46	2.68	2.42	3.47	16.79	17.85	17.59	17.69	17.59	17.69	17.59	17.69
Total Capital	10.00	2.90	50.06	100.95	43.47	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.00	0.00
Cash Flow	-10.00	-2.90	-50.06	-100.95	-43.47	28.36	37.10	39.01	38.60	40.26	26.27	27.92	27.51	27.67	27.51	16.67	27.51	27.67
Cum Cash Flow	-10.00	-12.90	-62.96	-163.91	-207.38	-179.02	-141.91	-102.90	-64.30	-24.04	2.23	30.15	57.66	85.33	112.84	129.51	157.02	184.69

CASE 2 TASMANIA (Continued)

							PRODUCTION	
YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	49.83	49.83	49.83	40.98	32.33	26.36	20.59	17.71
LESS								
Expenditure								
Capital Costs	1.80	12.80	2.60	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	33.23	22.48	32.43	26.43	17.53	11.81	5.79	-12.24
Undeducted Expendature	-6335.28	-8066.62	*********	-13138.00	-16782.81	-21459.56	-27453.12	-35132.58
Accum. Net Receipts	-6302.05	-8044.14	*********	-13111.57	-16765.28	-21447.75	-27447.32	-35144.81
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	49.83	49.83	49.83	40.98	32.33	26.36	20.59	17.71
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.28								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	35.03	35.28	35.03	26.43	17.53	11.81	5.79	3.16
Tax % 39.00	13.66	13.76	13.66	10.31	6.84	4.61	2.26	1.23
CASH FLOW								
Gas and Liquid Revenue	49.83	49.83	49.83	40.98	32.33	26.36	20.59	17.71
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	13.66	13.76	13.66	10.31	6.84	4.61	2.26	1.23
Total Capital	1.80	12.80	2.60	0.00	0.00	0.00	0.00	15.40
Cash Flow	19.57	8.72	18.77	16.12	10.69	7.20	3.53	-13.47
Cum Cash Flow	204.26	212.98	231.75	247.87	258.57	265.77	269.30	255.83

IRR %	10.00	15.00	20.00
NPV $(Millions)	0.01	-20.85	-25.77
IRR (CALC) %	10.00		

JOB NO 3002
CLIENT AMOCO
CASE 2 TASMANIA
CAPITAL $M 255.58
RATE GAS $/GJ. $2.88
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 15.00

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472250

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.68														
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.06	24.08	8.73													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.06	100.95	43.47	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$2.88				2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.88
Natural Gas Revenue						34.56	40.32	43.20	43.20	46.08	46.08	48.96	48.96	48.96	48.96	48.96	48.96	48.96
Sales Liquid Throughput BBLS/Y x 1000						880.00	980.00	1040.00	1020.00	1060.00	1040.00	1080.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						18.48	20.58	21.84	21.42	22.26	21.84	22.68	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						53.04	60.9	65.04	64.62	68.34	67.92	71.64	71.22	71.22	71.22	71.22	71.22	71.22

CASE 2 TASMANIA (Continued)

											PRODUCTION			
YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform						1.80	1.80	2.60						64.78
and Pipeline Fabrication														0.00
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														42.87
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	1.80	12.80	2.60	0.00	0.00	0.00	0.00	15.40	255.58
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	65.34
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	80.53
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	177.64
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$2.88				2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.88
Natural Gas Revenue						48.96	48.96	48.96	40.32	31.68	25.92	20.16	17.28	878.40
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19580.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	411.18
TOTAL REVENUE						71.22	71.22	71.22	58.59	46.17	37.68	29.4	25.26	1289.58

CASE 2 TASMANIA (Continued)

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						53.04	60.90	65.04	64.62	68.34	67.92	71.64	71.22	71.22	71.22	71.22	71.22	71.22
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.06	100.95	43.47	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.00	0.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
Net Annual Receipts	-10.00	-2.90	-50.06	-100.95	-43.47	43.46	56.17	60.56	59.89	63.86	63.19	67.16	66.49	66.74	66.49	55.74	66.49	66.74
Undeducted Expendature	0.00	-34.36	-47.69	-125.12	-289.37	-426.04	-489.70	-554.92	-632.78	-733.30	-856.89	-1015.93	-1214.43	-1469.36	-1795.36	-2212.95	-2761.23	-3449.27
Accum. Net Receipts	-10.00	-37.26	-97.75	-226.07	-332.84	-382.58	-433.53	-494.36	-572.89	-669.44	-793.70	-948.77	-1147.94	-1402.62	-1728.87	-2157.21	-2694.74	-3382.53
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						53.04	60.90	65.04	64.62	68.34	67.92	71.64	71.22	71.22	71.22	71.22	71.22	71.22
LESS																		
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
Depreciation on : 183.28						34.82	34.82	34.82	34.82	34.82								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						13.24	21.35	25.74	25.07	29.04	63.19	67.16	66.49	66.74	66.49	66.74	66.49	66.74
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	5.16	8.33	10.04	9.78	11.32	24.64	26.19	25.93	26.03	25.93	26.03	25.93	26.03
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	53.04	60.90	65.04	64.62	68.34	67.92	71.64	71.22	71.22	71.22	71.22	71.22	71.22
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	5.16	8.33	10.04	9.78	11.32	24.64	26.19	25.93	26.03	25.93	26.03	25.93	26.03
Total Capital	10.00	2.90	50.06	100.95	43.47	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.00	0.00
Cash Flow	-10.00	-2.90	-50.06	-100.95	-43.47	38.30	47.84	50.52	50.11	52.54	38.55	40.97	40.56	40.71	40.56	29.71	40.56	40.71
Cum Cash Flow	-10.00	-12.90	-62.96	-163.91	-207.38	-169.08	-121.24	-70.71	-20.60	31.93	70.48	111.45	152.01	192.72	233.28	262.99	303.55	344.26

CASE 2 TASMANIA (Continued)

							PRODUCTION	
YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	71.22	71.22	71.22	58.59	46.17	37.68	29.40	25.26
LESS								
Expenditure								
Capital Costs	1.80	12.80	2.60	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	54.62	43.87	53.82	44.04	31.37	23.13	14.60	-4.69
Undeducted Expendature	-4329.64	-5472.02	-6948.04	-8824.60	-11239.11	-14345.91	-18333.16	-23447.75
Accum. Net Receipts	-4275.02	-5428.15	-6894.22	-8780.56	-11207.74	-14322.78	-18318.56	-23452.44
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	71.22	71.22	71.22	58.59	46.17	37.68	29.40	25.26
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.28								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	56.42	56.67	56.42	44.04	31.37	23.13	14.60	10.71
Tax % 39.00	22.00	22.10	22.00	17.18	12.23	9.02	5.69	4.18
CASH FLOW								
Gas and Liquid Revenue	71.22	71.22	71.22	58.59	46.17	37.68	29.40	25.26
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	22.00	22.10	22.00	17.18	12.23	9.02	5.69	4.18
Total Capital	1.80	12.80	2.60	0.00	0.00	0.00	0.00	15.40
Cash Flow	32.62	21.77	31.82	26.86	19.14	14.11	8.91	-8.87
Cum Cash Flow	376.88	398.64	430.46	457.32	476.46	490.57	499.48	490.61

IRR %	10.00	15.00	20.00
NPV $(Millions)	42.59	0.00	-14.81
IRR (CALC) %	15.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472254

JOB NO 3002
CLIENT AMOCO
CASE 2 TASMANIA
CAPITAL $M 255.58
RATE GAS $/GJ. $4.60
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 20.00

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.68														
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.06	24.08	8.73													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.06	100.95	43.47	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$4.60				4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60
Natural Gas Revenue						55.15	64.34	68.94	68.94	73.54	73.54	78.13	78.13	78.13	78.13	78.13	78.13	78.13
Sales Liquid Throughput BBLS/Y x 1000						880.00	980.00	1040.00	1020.00	1060.00	1040.00	1080.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						18.48	20.58	21.84	21.42	22.26	21.84	22.68	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						73.632	84.924	90.78	90.36	95.796	95.376	100.812	100.392	100.392	100.392	100.392	100.392	100.392

472255

CASE 2 TASMANIA (Continued)

YEAR						14	15	16	17	18	19	PRODUCTION 20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform						1.80	1.80	2.60						64.78
and Pipeline Fabrication														0.00
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														42.87
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	1.80	12.80	2.60	0.00	0.00	0.00	0.00	15.40	255.58
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	65.34
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	80.53
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	177.64
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$4.60				4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60
Natural Gas Revenue						78.13	78.13	78.13	64.34	50.56	41.36	32.17	27.58	1401.78
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19580.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	411.18
TOTAL REVENUE						100.392	100.392	100.392	82.614	65.046	53.124	41.412	35.556	1812.96

CASE 2 TASMANIA (Continued)

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						73.63	84.92	90.78	90.36	95.80	95.38	100.81	100.39	100.39	100.39	100.39	100.39	100.39
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.06	100.95	43.47	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.00	0.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
Net Annual Receipts	-10.00	-2.90	-50.06	-100.95	-43.47	64.05	80.19	86.30	85.63	91.32	90.65	96.33	95.66	95.91	95.66	84.91	95.66	95.91
Undeducted Expendature	0.00	-34.36	-47.69	-125.12	-289.37	-426.04	-463.35	-490.43	-517.29	-552.53	-590.35	-639.62	-695.41	-767.68	-859.86	-978.17	-1143.37	-1341.07
Accum. Net Receipts	-10.00	-37.26	-97.75	-226.07	-332.84	-361.99	-383.15	-404.13	-431.66	-461.21	-499.70	-543.29	-599.75	-671.76	-764.20	-893.26	-1047.71	-1245.16
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						73.63	84.92	90.78	90.36	95.80	95.38	100.81	100.39	100.39	100.39	100.39	100.39	100.39
LESS																		
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
Depreciation on : 183.28						34.82	34.82	34.82	34.82	34.82								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						33.83	45.37	51.48	50.81	56.49	90.65	96.33	95.66	95.91	95.66	95.91	95.66	95.91
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	13.19	17.69	20.08	19.81	22.03	35.35	37.57	37.31	37.41	37.31	37.41	37.31	37.41
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	73.63	84.92	90.78	90.36	95.80	95.38	100.81	100.39	100.39	100.39	100.39	100.39	100.39
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	13.19	17.69	20.08	19.81	22.03	35.35	37.57	37.31	37.41	37.31	37.41	37.31	37.41
Total Capital	10.00	2.90	50.06	100.95	43.47	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.00	0.00
Cash Flow	-10.00	-2.90	-50.06	-100.95	-43.47	50.86	62.50	66.22	65.82	69.28	55.29	58.76	58.35	58.51	58.35	47.51	58.35	58.51
Cum Cash Flow	-10.00	-12.90	-62.96	-163.91	-207.38	-156.52	-94.02	-27.80	38.02	107.30	162.60	221.36	279.71	338.22	396.57	444.08	502.43	560.94

CASE 2 TASMANIA (Continued)

							PRODUCTION	
YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	100.39	100.39	100.39	82.61	65.05	53.12	41.41	35.56
LESS								
Expenditure								
Capital Costs	1.80	12.80	2.60	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	83.79	73.04	82.99	68.06	50.25	38.57	26.61	5.61
Undeducted Expendature	-1593.80	-1932.81	-2380.50	-2940.81	-3677.12	-4642.40	-5892.89	-7508.84
Accum. Net Receipts	-1510.01	-1859.77	-2297.51	-2872.75	-3626.87	-4603.82	-5866.28	-7503.23
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	100.39	100.39	100.39	82.61	65.05	53.12	41.41	35.56
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.28								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	85.59	85.84	85.59	68.06	50.25	38.57	26.61	21.01
Tax % 39.00	33.38	33.48	33.38	26.54	19.60	15.04	10.38	8.19
CASH FLOW								
Gas and Liquid Revenue	100.39	100.39	100.39	82.61	65.05	53.12	41.41	35.56
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	33.38	33.48	33.38	26.54	19.60	15.04	10.38	8.19
Total Capital	1.80	12.80	2.60	0.00	0.00	0.00	0.00	15.40
Cash Flow	50.41	39.56	49.61	41.52	30.65	23.53	16.23	-2.59
Cum Cash Flow	611.35	650.91	700.52	742.04	772.69	796.22	812.46	809.87

IRR %	10.00	15.00	20.00
NPV $(Millions)	100.30	28.20	-0.01
IRR (CALC) %	20.00		

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FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO	3002	
CLIENT	AMOCO	
CASE 3	TASMANIA	
CAPITAL	$M	261.84
RATE GAS	$/GJ.	$2.39
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	10.00

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	22.53														
Offshore Installation				45.00	26.32													
Onshore Plant, Marine Base				15.19														
Development Drilling					33.20													
Insurance, Contingency			10.06	24.43	9.61													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.06	107.15	69.13	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$2.39				2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39
Natural Gas Revenue						28.66	33.43	35.82	35.82	38.21	38.21	40.60	40.60	40.60	40.60	40.60	40.60	40.60
Sales Liquid Throughput BBLS/Y x 1000						1000.00	1080.00	1150.00	1110.00	1130.00	1080.00	1100.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						21.00	22.68	24.15	23.31	23.73	22.68	23.10	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						49.656	56.112	59.97	59.13	61.938	60.888	63.696	62.856	62.856	62.856	62.856	62.856	62.856

CASE 3 TASMANIA (Continued)

												PRODUCTION		
YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform								2.60						67.03
and Pipeline Fabrication														0.00
Offshore Installation														71.32
Onshore Plant, Marine Base														15.19
Development Drilling														33.20
Insurance, Contingency														44.10
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.60	0.00	0.00	0.00	0.00	15.40	261.84
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	106.68
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	170.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	308.55
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$2.39				2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39
Natural Gas Revenue						40.60	40.60	40.60	33.43	26.27	21.49	16.72	14.33	728.34
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	20130.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	422.73
TOTAL REVENUE						62.856	62.856	62.856	51.702	40.758	33.252	25.956	22.308	1151.07

CASE 3 TASMANIA (Continued)

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						49.66	56.11	59.97	59.13	61.94	60.89	63.70	62.86	62.86	62.86	62.86	62.86	62.86
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.06	107.15	69.13	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Operating Costs						15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	-10.00	-2.90	-50.06	-107.15	-69.13	30.01	41.31	45.42	44.33	47.39	46.09	49.15	48.06	48.31	48.06	48.31	48.06	48.31
Undeducted Expendature	0.00	-34.36	-47.69	-125.12	-297.31	-469.04	-561.97	-666.44	-794.91	-960.74	-1169.09	-1437.44	-1777.01	-2213.06	-2770.89	-3485.23	-4399.26	-5569.54
Accum. Net Receipts	-10.00	-37.26	-97.75	-232.27	-366.44	-439.04	-520.66	-621.02	-750.58	-913.35	-1123.00	-1388.29	-1728.96	-2164.76	-2722.83	-3436.92	-4351.20	-5521.24
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						49.66	56.11	59.97	59.13	61.94	60.89	63.70	62.86	62.86	62.86	62.86	62.86	62.86
LESS																		
Total Operating Costs						15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 193.14						36.70	36.70	36.70	36.70	36.70								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						-2.09	4.62	8.72	7.63	10.69	46.09	49.15	48.06	48.31	48.06	48.31	48.06	48.31
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	0.00	1.80	3.40	2.98	4.17	17.97	19.17	18.74	18.84	18.74	18.84	18.74	18.84
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	49.66	56.11	59.97	59.13	61.94	60.89	63.70	62.86	62.86	62.86	62.86	62.86	62.86
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	0.00	1.80	3.40	2.98	4.17	17.97	19.17	18.74	18.84	18.74	18.84	18.74	18.84
Total Capital	10.00	2.90	50.06	107.15	69.13	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cash Flow	-10.00	-2.90	-50.06	-107.15	-69.13	30.01	39.51	42.02	41.35	43.22	28.11	29.98	29.31	29.47	29.31	29.47	29.31	29.47
Cum Cash Flow	-10.00	-12.90	-62.96	-170.11	-239.24	-209.23	-169.72	-127.70	-86.35	-43.13	-15.02	14.96	44.27	73.74	103.05	132.52	161.84	191.30

CASE 3 TASMANIA (Continued)

						PRODUCTION		
YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	62.86	62.86	62.86	51.70	40.76	33.25	25.96	22.31
LESS								
Expenditure								
Capital Costs	0.00	0.00	2.60	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	48.06	48.31	45.46	37.15	25.96	18.70	11.16	-7.64
Undeducted Expendature	-7067.18	-8984.48	*********	-14582.84	-18618.49	-23798.44	-30438.06	-38946.44
Accum. Net Receipts	-7019.13	-8936.17	*********	-14545.69	-18592.53	-23779.73	-30426.90	-38954.08
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	62.86	62.86	62.86	51.70	40.76	33.25	25.96	22.31
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 193.14								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	48.06	48.31	48.06	37.15	25.96	18.70	11.16	7.76
Tax % 39.00	18.74	18.84	18.74	14.49	10.12	7.29	4.35	3.03
CASH FLOW								
Gas and Liquid Revenue	62.86	62.86	62.86	51.70	40.76	33.25	25.96	22.31
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	18.74	18.84	18.74	14.49	10.12	7.29	4.35	3.03
Total Capital	0.00	0.00	2.60	0.00	0.00	0.00	0.00	15.40
Cash Flow	29.31	29.47	26.71	22.66	15.83	11.41	6.81	-10.67
Cum Cash Flow	220.62	250.08	276.80	299.46	315.29	326.70	333.51	322.84

IRR %	10.00	15.00	20.00
NPV $(Millions)	0.00	-24.15	-29.29
IRR (CALC) %	10.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 3 TASMANIA
CAPITAL $M 261.84
RATE GAS $/GJ. $3.84
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 15.00

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	22.53														
Offshore Installation				45.00	26.32													
Onshore Plant, Marine Base				15.19														
Development Drilling					33.20													
Insurance, Contingency			10.06	24.43	9.61													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.06	107.15	69.13	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$3.84				3.84	3.84	3.84	3.84	3.84	3.84	3.84	3.84	3.84	3.84	3.84	3.84	3.84
Natural Gas Revenue						46.13	53.82	57.66	57.66	61.50	61.50	65.35	65.35	65.35	65.35	65.35	65.35	65.35
Sales Liquid Throughput BBLS/Y x 1000						1000.00	1080.00	1150.00	1110.00	1130.00	1080.00	1100.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						21.00	22.68	24.15	23.31	23.73	22.68	23.10	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						67.128	76.496	81.81	80.97	85.234	84.184	88.448	87.608	87.608	87.608	87.608	87.608	87.608

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YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform								2.60						67.03
and Pipeline Fabrication														0.00
Offshore Installation														71.32
Onshore Plant, Marine Base														15.19
Development Drilling														33.20
Insurance, Contingency														44.10
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.60	0.00	0.00	0.00	0.00	15.40	261.84
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	106.68
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	170.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	308.55
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$3.84				3.84	3.84	3.84	3.84	3.84	3.84	3.84	3.84	3.84
Natural Gas Revenue						65.35	65.35	65.35	53.82	42.28	34.60	26.91	23.06	1172.42
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	20130.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	422.73
TOTAL REVENUE						87.608	87.608	87.608	72.086	56.774	46.356	36.148	31.044	1595.15

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			DEVEI									DUCTI						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						67.13	76.50	81.81	80.97	85.23	84.18	88.45	87.61	87.61	87.61	87.61	87.61	87.61
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.06	107.15	69.13	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Operating Costs						15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	-10.00	-2.90	-50.06	-107.15	-69.13	47.48	61.70	67.26	66.17	70.68	69.38	73.90	72.81	73.06	72.81	73.06	72.81	73.06
Undeducted Expendature	0.00	-34.36	-47.69	-125.12	-297.31	-469.04	-539.60	-611.72	-696.91	-807.35	-942.93	-1118.14	-1336.63	-1617.69	-1977.13	-2437.53	-3026.53	-3780.76
Accum. Net Receipts	-10.00	-37.26	-97.75	-232.27	-366.44	-421.57	-477.91	-544.46	-630.74	-736.66	-873.55	-1044.24	-1263.82	-1544.63	-1904.32	-2364.48	-2953.72	-3707.71
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						67.13	76.50	81.81	80.97	85.23	84.18	88.45	87.61	87.61	87.61	87.61	87.61	87.61
LESS																		
Total Operating Costs						15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 193.14						36.70	36.70	36.70	36.70	36.70								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						15.38	25.00	30.56	29.47	33.99	69.38	73.90	72.81	73.06	72.81	73.06	72.81	73.06
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	6.00	9.75	11.92	11.49	13.26	27.06	28.82	28.40	28.49	28.40	28.49	28.40	28.49
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	67.13	76.50	81.81	80.97	85.23	84.18	88.45	87.61	87.61	87.61	87.61	87.61	87.61
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	6.00	9.75	11.92	11.49	13.26	27.06	28.82	28.40	28.49	28.40	28.49	28.40	28.49
Total Capital	10.00	2.90	50.06	107.15	69.13	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cash Flow	-10.00	-2.90	-50.06	-107.15	-69.13	41.48	51.95	55.34	54.68	57.43	42.32	45.08	44.41	44.57	44.41	44.57	44.41	44.57
Cum Cash Flow	-10.00	-12.90	-62.96	-170.11	-239.24	-197.76	-145.81	-90.47	-35.80	21.63	63.95	109.03	153.44	198.01	242.42	286.99	331.40	375.97

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CASE        TAS        (Con
                                                                                    PRODUCTION
YEAR                                        14       15       16       17        18        19        20        21
=================================================================================================================
RESOURCE RENT TAX
Receipts                                 87.61    87.61    87.61    72.09     56.77     46.36     36.15     31.04
LESS
Expenditure
Capital Costs                             0.00     0.00     2.60     0.00      0.00      0.00      0.00     15.40
Operating Costs                          14.80    14.55    14.80    14.55     14.80     14.55     14.80     14.55
-----------------------------------------------------------------------------------------------------------------
Net Annual Receipts                      72.81    73.06    70.21    57.54     41.97     31.81     21.35      1.09

Undeducted Expendature                -4745.86 -5981.51 -7562.82 -9590.54 -12202.25 -15565.15 -19882.68 -25422.51
Accum. Net Receipts                   -4673.06 -5908.45 -7492.61 -9533.01 -12160.27 -15533.35 -19861.33 -25421.41
RTT      %     40.00                      0.00     0.00     0.00     0.00      0.00      0.00      0.00      0.00
-----------------------------------------------------------------------------------------------------------------
TAX SCHEDULE
Gas and Liquid Revenue                   87.61    87.61    87.61    72.09     56.77     46.36     36.15     31.04
LESS
Total Operating Costs                    14.80    14.55    14.80    14.55     14.80     14.55     14.80     14.55
Depreciation on :      193.14
RRT                                       0.00     0.00     0.00     0.00      0.00      0.00      0.00      0.00
-----------------------------------------------------------------------------------------------------------------
Taxable Income                           72.81    73.06    72.81    57.54     41.97     31.81     21.35     16.49
Tax      %     39.00                     28.40    28.49    28.40    22.44     16.37     12.40      8.33      6.43


CASH FLOW
Gas and Liquid Revenue                   87.61    87.61    87.61    72.09     56.77     46.36     36.15     31.04
LESS
Total Operating Costs                    14.80    14.55    14.80    14.55     14.80     14.55     14.80     14.55
RTT                                       0.00     0.00     0.00     0.00      0.00      0.00      0.00      0.00
Tax                                      28.40    28.49    28.40    22.44     16.37     12.40      8.33      6.43
Total Capital                             0.00     0.00     2.60     0.00      0.00      0.00      0.00     15.40
-----------------------------------------------------------------------------------------------------------------
Cash Flow                                44.41    44.57    41.81    35.10     25.60     19.40     13.02     -5.34
Cum Cash Flow                           420.38   464.95   506.76   541.85    567.46    586.86    599.88    594.54
=================================================================================================================


IRR %                        10.00   15.00   20.00

NPV $(Millions)              49.28   -0.01  -16.60

IRR (CALC)  %                15.00
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FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO	3002	
CLIENT	AMOCO	
CASE 3	TASMANIA	
CAPITAL	$M	261.84
RATE GAS	$/GJ.	$5.77
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	20.00

	DEVELOPMENT				PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	22.53														
Offshore Installation				45.00	26.32													
Onshore Plant, Marine Base				15.19														
Development Drilling					33.20													
Insurance, Contingency			10.06	24.43	9.61													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.06	107.15	69.13	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$5.77				5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77
Natural Gas Revenue						69.24	80.78	86.55	86.55	92.32	92.32	98.09	98.09	98.09	98.09	98.09	98.09	98.09
Sales Liquid Throughput BBLS/Y x 1000						1000.00	1080.00	1150.00	1110.00	1130.00	1080.00	1100.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						21.00	22.68	24.15	23.31	23.73	22.68	23.10	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						90.24	103.46	110.7	109.86	116.05	115	121.19	120.35	120.35	120.35	120.35	120.35	120.35

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YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform								2.60						67.03
and Pipeline Fabrication														0.00
Offshore Installation														71.32
Onshore Plant, Marine Base														15.19
Development Drilling														33.20
Insurance, Contingency														44.10
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.60	0.00	0.00	0.00	0.00	15.40	261.84
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	106.68
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	170.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	308.55
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$5.77				5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77
Natural Gas Revenue						98.09	98.09	98.09	80.78	63.47	51.93	40.39	34.62	1759.85
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	20130.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	422.73
TOTAL REVENUE						120.35	120.35	120.35	99.05	77.96	63.69	49.63	42.6	2182.58

			DEVEL									DUCTI						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						90.24	103.46	110.70	109.86	116.05	115.00	121.19	120.35	120.35	120.35	120.35	120.35	120.35
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.06	107.15	69.13	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Operating Costs						15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	-10.00	-2.90	-50.06	-107.15	-69.13	70.59	88.66	96.15	95.06	101.50	100.20	106.64	105.55	105.80	105.55	105.80	105.55	105.80
Undeducted Expendature	0.00	-34.36	-47.69	-125.12	-297.31	-469.04	-510.02	-539.34	-567.28	-604.45	-643.77	-695.77	-754.09	-830.13	-927.15	-1051.64	-1210.68	-1414.56
Accum. Net Receipts	-10.00	-37.26	-97.75	-232.27	-366.44	-398.45	-421.36	-443.19	-472.22	-502.95	-543.57	-589.13	-648.54	-724.33	-821.60	-945.84	-1105.13	-1308.76
RRT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						90.24	103.46	110.70	109.86	116.05	115.00	121.19	120.35	120.35	120.35	120.35	120.35	120.35
LESS																		
Total Operating Costs						15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 193.14						36.70	36.70	36.70	36.70	36.70								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						38.49	51.96	59.45	58.36	64.80	100.20	106.64	105.55	105.80	105.55	105.80	105.55	105.80
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	15.01	20.27	23.19	22.76	25.27	39.08	41.59	41.16	41.26	41.16	41.26	41.16	41.26
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	90.24	103.46	110.70	109.86	116.05	115.00	121.19	120.35	120.35	120.35	120.35	120.35	120.35
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	15.01	20.27	23.19	22.76	25.27	39.08	41.59	41.16	41.26	41.16	41.26	41.16	41.26
Total Capital	10.00	2.90	50.06	107.15	69.13	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cash Flow	-10.00	-2.90	-50.06	-107.15	-69.13	55.58	68.39	72.96	72.30	76.23	61.12	65.05	64.39	64.54	64.39	64.54	64.39	64.54
Cum Cash Flow	-10.00	-12.90	-62.96	-170.11	-239.24	-183.66	-115.27	-42.30	29.99	106.22	167.34	232.39	296.78	361.32	425.70	490.24	554.62	619.16

YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	120.35	120.35	120.35	99.05	77.96	63.69	49.63	42.60
LESS								
Expenditure								
Capital Costs	0.00	0.00	2.60	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	105.55	105.80	102.95	84.50	63.16	49.14	34.83	12.65
Undeducted Expendature	-1675.22	-2009.18	-2436.32	-2986.72	-3714.84	-4674.15	-5920.01	-7533.03
Accum. Net Receipts	-1569.67	-1903.38	-2333.37	-2902.22	-3651.68	-4625.01	-5885.18	-7520.38
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	120.35	120.35	120.35	99.05	77.96	63.69	49.63	42.60
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 193.14								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	105.55	105.80	105.55	84.50	63.16	49.14	34.83	28.05
Tax % 39.00	41.16	41.26	41.16	32.96	24.63	19.16	13.58	10.94
CASH FLOW								
Gas and Liquid Revenue	120.35	120.35	120.35	99.05	77.96	63.69	49.63	42.60
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	41.16	41.26	41.16	32.96	24.63	19.16	13.58	10.94
Total Capital	0.00	0.00	2.60	0.00	0.00	0.00	0.00	15.40
Cash Flow	64.39	64.54	61.79	51.55	38.53	29.98	21.25	1.71
Cum Cash Flow	683.55	748.09	809.87	861.42	899.94	929.92	951.17	952.88

IRR %	10.00	15.00	20.00
NPV $(Millions)	114.05	31.64	0.00
IRR (CALC) %	20.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472270

JOB NO	3002	
CLIENT	AMOCO	
CASE 4	TASMANIA	
CAPITAL	$M	258.08
RATE GAS	$/GJ.	$2.04
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	10.00

		DEVELOPMENT				PRODUCTION										
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	TOTAL
CAPITAL INVESTMENT																
Exploration Well	10.0															10.00
Pre-Engr., Investigation		1.00														1.00
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	25.88								5.00		2.60	2.60	77.98
Offshore Installation				45.00	30.28											75.28
Onshore Plant, Marine Base				15.19												15.19
Development Drilling					11.20											11.20
Insurance, Contingency			10.25	26.55	10.63											47.43
Working Capital						4.60									-4.60	0.00
Platform Removal															20.00	20.00
Total Capital	10.00	2.90	50.25	112.62	52.11	4.60	0.00	0.00	0.00	0.00	0.00	5.00	0.00	2.60	18.00	258.08
OPERATING COSTS																
Start Up						0.50										0.50
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	5.08	5.08	5.08	5.08	31.72
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	8.10	8.10	8.10	8.10	39.66
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	5.20
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	8.50
Well Workover							0.25		0.25		0.25		0.25		0.25	1.25
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55	14.80	86.83
REVENUE																
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	156.00
Gas Selling Price $/GJ		$2.04				2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04
Natural Gas Revenue						24.44	28.52	30.56	30.56	32.59	32.59	34.63	34.63	34.63	34.63	317.77
Sales Liquid Throughput BBLS/Y x 1000						1410.00	1620.00	1690.00	1620.00	1720.00	1720.00	1830.00	1830.00	1830.00	1830.00	17100.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						29.61	34.02	35.49	34.02	36.12	36.12	38.43	38.43	38.43	38.43	359.10
TOTAL REVENUE						54.054	62.538	66.045	64.575	68.712	68.712	73.059	73.059	73.059	73.059	676.872

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT .

SE 4 ASMAN

(Fi Quarte 89)

	DEVELOPMENT					PRODUCTION									
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10
RESOURCE RENT TAX															
Receipts						54.05	62.54	66.05	64.58	68.71	68.71	73.06	73.06	73.06	73.06
LESS															
Expenditure															
Capital Costs	10.00	2.90	50.25	112.62	52.11	4.60	0.00	0.00	0.00	0.00	0.00	5.00	0.00	2.60	18.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55	14.80
Net Annual Receipts	-10.00	-2.90	-50.25	-112.62	-52.11	44.47	57.81	61.57	59.85	64.23	63.98	53.51	58.26	55.91	40.26
Undeducted Expendature	0.00	-34.36	-47.69	-125.37	-304.62	-456.62	-527.54	-601.26	-690.81	-807.64	-951.56	-1136.10	-1385.72	-1699.15	-2103.35
Accum. Net Receipts	-10.00	-37.26	-97.94	-237.99	-356.73	-412.14	-469.74	-539.70	-630.97	-743.41	-887.58	-1082.59	-1327.46	-1643.24	-2063.09
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE															
Gas and Liquid Revenue						54.05	62.54	66.05	64.58	68.71	68.71	73.06	73.06	73.06	73.06
LESS															
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55	14.80
Depreciation on : 203.78						38.72	38.72	38.72	38.72	38.72					
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						10.36	19.09	22.85	21.13	25.51	63.98	58.51	58.26	58.51	58.26
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	4.04	7.45	8.91	8.24	9.95	24.95	22.82	22.72	22.82	22.72
CASH FLOW															
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	54.05	62.54	66.05	64.58	68.71	68.71	73.06	73.06	73.06	73.06
LESS															
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55	14.80
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	4.04	7.45	8.91	8.24	9.95	24.95	22.82	22.72	22.82	22.72
Total Capital	10.00	2.90	50.25	112.62	52.11	4.60	0.00	0.00	0.00	0.00	0.00	5.00	0.00	2.60	18.00
Cash Flow	-10.00	-2.90	-50.25	-112.62	-52.11	40.44	50.36	52.65	51.61	54.28	39.03	30.69	35.54	33.09	17.54
Cum Cash Flow	-10.00	-12.90	-63.15	-175.77	-227.88	-187.44	-137.08	-84.43	-32.82	21.46	60.49	91.18	126.72	159.81	177.35

IRR %	10.00	15.00	20.00
NPV $(Millions)	-0.02	-18.46	-23.77
IRR (CALC) %	10.00		

CASE 4 TASMANIA

			DEVELOPMENT									PRODUCTION			
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10
RESOURCE RENT TAX															
Receipts						71.01	82.32	87.24	85.77	91.32	91.32	97.08	97.08	97.08	97.08
LESS															
Expenditure															
Capital Costs	10.00	2.90	50.25	112.62	52.11	4.60	0.00	0.00	0.00	0.00	0.00	5.00	0.00	2.60	18.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55	14.80
Net Annual Receipts	-10.00	-2.90	-50.25	-112.62	-52.11	61.43	77.59	82.76	81.04	86.84	86.59	77.53	82.28	79.93	64.28
Undeducted Expendature	0.00	-34.36	-47.69	-125.37	-304.62	-456.62	-505.84	-548.16	-595.71	-658.78	-732.09	-826.24	-958.34	-1121.36	-1333.03
Accum. Net Receipts	-10.00	-37.26	-97.94	-237.99	-356.73	-395.19	-428.25	-465.40	-514.67	-571.94	-645.50	-748.71	-876.06	-1041.43	-1268.75
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE															
Gas and Liquid Revenue						71.01	82.32	87.24	85.77	91.32	91.32	97.08	97.08	97.08	97.08
LESS															
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55	14.80
Depreciation on : 203.78						38.72	38.72	38.72	38.72	38.72					
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						27.31	38.87	44.04	42.32	48.12	86.59	82.53	82.28	82.53	82.28
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	10.65	15.16	17.18	16.51	18.77	33.77	32.19	32.09	32.19	32.09
CASH FLOW															
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	71.01	82.32	87.24	85.77	91.32	91.32	97.08	97.08	97.08	97.08
LESS															
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55	14.80
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	10.65	15.16	17.18	16.51	18.77	33.77	32.19	32.09	32.19	32.09
Total Capital	10.00	2.90	50.25	112.62	52.11	4.60	0.00	0.00	0.00	0.00	0.00	5.00	0.00	2.60	18.00
Cash Flow	-10.00	-2.90	-50.25	-112.62	-52.11	50.78	62.43	65.58	64.53	68.07	52.82	45.34	50.19	47.74	32.19
Cum Cash Flow	-10.00	-12.90	-63.15	-175.77	-227.88	-177.10	-114.67	-49.09	15.45	83.52	136.34	181.68	231.87	279.62	311.81

IRR %	10.00	15.00	20.00
NPV $(Millions)	34.12	-0.01	-13.38
IRR (CALC) %	15.00		

JOB NO 3002
CLIENT AMOCO
CASE 4 TASMANIA
CAPITAL $M 258.08
RATE GAS $/GJ. $5.27
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 20.00

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

	DEVELOPMENT					PRODUCTION										
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	TOTAL
CAPITAL INVESTMENT																
Exploration Well	10.0															10.00
Pre-Engr., Investigation		1.00														1.00
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	25.88								5.00		2.60	2.60	77.98
Offshore Installation				45.00	30.28											75.28
Onshore Plant, Marine Base				15.19												15.19
Development Drilling					11.20											11.20
Insurance, Contingency			10.25	26.55	10.63											47.43
Working Capital						4.60									-4.60	0.00
Platform Removal															20.00	20.00
Total Capital	10.00	2.90	50.25	112.62	52.11	4.60	0.00	0.00	0.00	0.00	0.00	5.00	0.00	2.60	18.00	258.08
OPERATING COSTS																
Start Up						0.50										0.50
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	5.08	5.08	5.08	5.08	31.72
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	8.10	8.10	8.10	8.10	39.66
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	5.20
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	8.50
Well Workover							0.25		0.25		0.25		0.25		0.25	1.25
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55	14.80	86.83
REVENUE																
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	156.00
Gas Selling Price $/GJ		$5.27				5.27	5.27	5.27	5.27	5.27	5.27	5.27	5.27	5.27	5.27	5.27
Natural Gas Revenue						63.24	73.78	79.05	79.05	84.32	84.32	89.59	89.59	89.59	89.59	822.12
Sales Liquid Throughput BBLS/Y x 1000						1410.00	1620.00	1690.00	1620.00	1720.00	1720.00	1830.00	1830.00	1830.00	1830.00	17100.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						29.61	34.02	35.49	34.02	36.12	36.12	38.43	38.43	38.43	38.43	359.10
TOTAL REVENUE						92.85	107.8	114.54	113.07	120.44	120.44	128.02	128.02	128.02	128.02	1181.22

472274

CASE 4 TASMANIA

	DEVELOPMENT					PRODUCTION									
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10
RESOURCE RENT TAX															
Receipts						92.85	107.80	114.54	113.07	120.44	120.44	128.02	128.02	128.02	128.02
LESS															
Expenditure															
Capital Costs	10.00	2.90	50.25	112.62	52.11	4.60	0.00	0.00	0.00	0.00	0.00	5.00	0.00	2.60	18.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55	14.80
Net Annual Receipts	-10.00	-2.90	-50.25	-112.62	-52.11	83.27	103.07	110.06	108.34	115.96	115.71	108.47	113.22	110.87	95.22
Undeducted Expendature	0.00	-34.36	-47.69	-125.37	-304.62	-456.62	-477.89	-479.76	-473.22	-467.05	-449.39	-427.11	-407.86	-377.15	-340.83
Accum. Net Receipts	-10.00	-37.26	-97.94	-237.99	-356.73	-373.35	-374.82	-369.70	-364.88	-351.09	-333.68	-318.64	-294.64	-266.28	-245.61
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE															
Gas and Liquid Revenue						92.85	107.80	114.54	113.07	120.44	120.44	128.02	128.02	128.02	128.02
LESS															
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55	14.80
Depreciation on : 203.78						38.72	38.72	38.72	38.72	38.72					
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						49.15	64.35	71.34	69.62	77.24	115.71	113.47	113.22	113.47	113.22
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	19.17	25.10	27.82	27.15	30.12	45.13	44.25	44.16	44.25	44.16
CASH FLOW															
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	92.85	107.80	114.54	113.07	120.44	120.44	128.02	128.02	128.02	128.02
LESS															
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55	14.80
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	19.17	25.10	27.82	27.15	30.12	45.13	44.25	44.16	44.25	44.16
Total Capital	10.00	2.90	50.25	112.62	52.11	4.60	0.00	0.00	0.00	0.00	0.00	5.00	0.00	2.60	18.00
Cash Flow	-10.00	-2.90	-50.25	-112.62	-52.11	64.10	77.97	82.24	81.19	85.84	70.58	64.22	69.06	66.62	51.06
Cum Cash Flow	-10.00	-12.90	-63.15	-175.77	-227.88	-163.78	-85.81	-3.57	77.62	163.45	234.04	298.25	367.32	433.93	485.00

IRR %	10.00	15.00	20.00
NPV $(Millions)	78.08	23.76	-0.01
IRR (CALC) %	20.00		

SENSITIVITY (OPERATING COST)

VICTORIA AND TASMAINIA

UNMANNED AND FULLY MANNED

472276

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 1 VICTORIA Sensitivity Unmanned

CAPITAL	$M	280.73
RATE GAS	$/GJ.	$1.66
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	15.00

	DEVELOPMENT					PRODUCTION													
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	16.28						2.60			2.60						63.38
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	23.88														68.88
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.90	24.85	13.64														48.39
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	280.73
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	24.70
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	15.73
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						5.04	4.79	4.54	4.79	4.54	4.79	4.54	4.79	4.54	4.79	4.54	4.79	4.54	61.02
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$1.66				1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66
Natural Gas Revenue						49.83	49.83	49.83	49.83	49.83	49.83	49.83	49.83	39.86	29.90	19.93	14.95	9.97	513.25
Sales Liquid Throughput BBLS/Y x 1000						1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19270.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						39.27	39.27	39.27	39.27	39.27	39.27	39.27	39.27	31.50	23.52	15.75	11.76	7.98	404.67
TOTAL REVENUE						89.1	89.1	89.1	89.1	89.1	89.1	89.1	89.1	71.364	53.418	35.682	26.709	17.946	917.919

CASE 1 VICTORIA (Continued)

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						89.10	89.10	89.10	89.10	89.10	89.10	89.10	89.10	71.36	53.42	35.68	26.71	17.95
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						5.04	4.79	4.54	4.79	4.54	4.79	4.54	4.79	4.54	4.79	4.54	4.79	4.54
Net Annual Receipts	-10.00	-2.90	-49.90	-103.01	-68.72	79.06	84.31	84.56	84.31	81.96	84.31	63.56	81.71	66.82	48.63	31.14	21.92	-1.59
Undeducted Expendature	0.00	-34.36	-47.69	-124.92	-291.75	-461.40	-489.40	-518.51	-555.46	-603.07	-667.02	-745.86	-873.35	-1013.30	-1211.48	-1488.46	-1865.36	-2359.61
Accum. Net Receipts	-10.00	-37.26	-97.59	-227.93	-360.47	-382.34	-405.09	-433.95	-471.15	-521.11	-582.71	-682.30	-791.64	-946.47	-1162.86	-1457.31	-1843.44	-2361.20
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						89.10	89.10	89.10	89.10	89.10	89.10	89.10	89.10	71.36	53.42	35.68	26.71	17.95
LESS																		
Total Operating Costs						5.04	4.79	4.54	4.79	4.54	4.79	4.54	4.79	4.54	4.79	4.54	4.79	4.54
Depreciation on : 190.43						36.18	36.18	36.18	36.18	36.18								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						47.88	48.13	48.38	48.13	48.38	84.31	84.56	84.31	66.82	48.63	31.14	21.92	13.41
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	18.67	18.77	18.87	18.77	18.87	32.88	32.98	32.88	26.06	18.96	12.15	8.55	5.23
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	89.10	89.10	89.10	89.10	89.10	89.10	89.10	89.10	71.36	53.42	35.68	26.71	17.95
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	4.54	4.79	4.54	4.79	4.54	4.79	4.54	4.79	4.54	4.79	4.54
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	18.67	18.77	18.87	18.77	18.87	32.88	32.98	32.88	26.06	18.96	12.15	8.55	5.23
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.90	-103.01	-68.72	60.39	65.54	65.69	65.54	63.09	51.43	30.58	48.83	40.76	29.66	19.00	13.37	-6.82
Cum Cash Flow	-10.00	-12.90	-62.80	-165.81	-234.53	-174.14	-108.60	-42.91	22.63	85.72	137.15	167.73	216.56	257.32	286.99	305.98	319.36	312.53

IRR %	10.00	15.00	20.00
NPV $(Millions)	33.85	0.00	-13.21
IRR (CALC) %	15.00		

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FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 1 VICTORIA Sensitivity Fully Manned
CAPITAL $M 280.73
RATE GAS $/GJ. $2.03
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 15.00

			DEVELOPMENT									PRODUCTION							
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	16.28						2.60			2.60						63.38
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	23.88														68.88
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.90	24.85	13.64														48.39
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	280.73
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	66.04
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	105.30
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	191.93
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$2.03				2.03	2.03	2.03	2.03	2.03	2.03	2.03	2.03	2.03	2.03	2.03	2.03	2.03	2.03
Natural Gas Revenue						60.99	60.99	60.99	60.99	60.99	60.99	60.99	60.99	48.79	36.59	24.40	18.30	12.20	628.20
Sales Liquid Throughput BBLS/Y x 1000						1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19270.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						39.27	39.27	39.27	39.27	39.27	39.27	39.27	39.27	31.50	23.52	15.75	11.76	7.98	404.67
TOTAL REVENUE						100.26	100.26	100.26	100.26	100.26	100.26	100.26	100.26	80.292	60.114	40.146	30.057	20.178	1032.867

CASE 1 VICTORIA (Continued)

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						100.26	100.26	100.26	100.26	100.26	100.26	100.26	100.26	80.29	60.11	40.15	30.06	20.18
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-10.00	-2.90	-49.90	-103.01	-68.72	80.15	85.40	85.65	85.40	83.05	85.40	64.65	82.80	65.68	45.25	25.54	15.20	-9.43
Undeducted Expendature	0.00	-34.36	-47.69	-124.92	-291.75	-461.40	-488.00	-515.33	-549.99	-594.67	-654.88	-728.93	-850.28	-982.37	-1173.37	-1443.98	-1815.61	-2304.53
Accum. Net Receipts	-10.00	-37.26	-97.59	-227.93	-360.47	-381.25	-402.60	-429.68	-464.59	-511.62	-569.48	-664.28	-767.48	-916.69	-1128.11	-1418.45	-1800.41	-2313.96
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						100.26	100.26	100.26	100.26	100.26	100.26	100.26	100.26	80.29	60.11	40.15	30.06	20.18
LESS																		
Total Operating Costs						15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 190.43						36.18	36.18	36.18	36.18	36.18								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						48.97	49.22	49.47	49.22	49.47	85.40	85.65	85.40	65.68	45.25	25.54	15.20	5.57
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	19.10	19.20	19.29	19.20	19.29	33.31	33.40	33.31	25.62	17.65	9.96	5.93	2.17
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	100.26	100.26	100.26	100.26	100.26	100.26	100.26	100.26	80.29	60.11	40.15	30.06	20.18
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	15.11	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	19.10	19.20	19.29	19.20	19.29	33.31	33.40	33.31	25.62	17.65	9.96	5.93	2.17
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.90	-103.01	-68.72	61.05	66.20	66.36	66.20	63.76	52.09	31.25	49.49	40.07	27.60	15.58	9.27	-11.60
Cum Cash Flow	-10.00	-12.90	-62.80	-165.81	-234.53	-173.48	-107.27	-40.92	25.29	89.05	141.14	172.39	221.88	261.95	289.55	305.13	314.40	302.80

IRR %	10.00	15.00	20.00
NPV $(Millions)	33.25	0.00	-13.07
IRR (CALC) %	15.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

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JOB NO 3002
CLIENT AMOCO
CASE 1 TASMANIA Sensitivity Fully Manned

CAPITAL	$M	258.19
RATE GAS	$/GJ.	$3.57
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	15.00

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.13												3.40		
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.29	24.40	8.94													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$3.57				$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57
Natural Gas Revenue						42.83	49.97	53.54	53.54	57.10	57.10	60.67	60.67	60.67	60.67	60.67	60.67	60.67
Sales Liquid Throughput BBLS/Y x 1000						750.00	870.00	940.00	940.00	1000.00	1000.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						15.75	18.27	19.74	19.74	21.00	21.00	22.26	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						58.578	68.236	73.275	73.275	78.104	78.104	82.933	82.933	82.933	82.933	82.933	82.933	82.933

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CASE 1 TASMANIA Sensitivity Fully Manned (Continued)

												PRODUCTION		
YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform and Pipeline Fabrication						2.60	2.60							66.63
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														43.63
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40	258.19
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	106.68
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	170.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	308.55
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$3.57				3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57
Natural Gas Revenue						60.67	60.67	60.67	49.97	39.26	32.12	24.98	21.41	1088.55
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19040.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	399.84
TOTAL REVENUE						82.933	82.933	82.933	68.236	53.749	43.881	34.223	29.394	1488.385

CASE 1 TASMANIA Sensitivity Fully Manned (Continued)

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						58.58	68.24	73.27	73.27	78.10	78.10	82.93	82.93	82.93	82.93	82.93	82.93	82.93
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Operating Costs						15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	-10.00	-2.90	-50.29	-100.72	-43.68	38.93	53.44	58.72	58.47	63.55	63.30	68.38	68.13	68.38	68.13	53.98	68.13	68.38
Undeducted Expendature	0.00	-34.36	-47.69	-125.42	-289.46	-426.41	-495.98	-566.46	-649.90	-757.03	-887.64	-1055.15	-1263.07	-1529.52	-1870.25	-2306.71	-2883.49	-3603.66
Accum. Net Receipts	-10.00	-37.26	-97.98	-226.14	-333.14	-387.49	-442.55	-507.74	-591.43	-693.47	-824.34	-986.77	-1194.94	-1461.13	-1802.12	-2252.73	-2815.36	-3535.28
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						58.58	68.24	73.27	73.27	78.10	78.10	82.93	82.93	82.93	82.93	82.93	82.93	82.93
LESS																		
Total Operating Costs						15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.49						34.86	34.86	34.86	34.86	34.86								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						8.66	18.57	23.86	23.61	28.69	63.30	68.38	68.13	68.38	68.13	68.38	68.13	68.38
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	3.38	7.24	9.31	9.21	11.19	24.69	26.67	26.57	26.67	26.57	26.67	26.57	26.67
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	58.58	68.24	73.27	73.27	78.10	78.10	82.93	82.93	82.93	82.93	82.93	82.93	82.93
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	15.05	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	3.38	7.24	9.31	9.21	11.19	24.69	26.67	26.57	26.67	26.57	26.67	26.57	26.67
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Cash Flow	-10.00	-2.90	-50.29	-100.72	-43.68	35.55	46.19	49.42	49.27	52.36	38.62	41.71	41.56	41.71	41.56	27.31	41.56	41.71
Cum Cash Flow	-10.00	-12.90	-63.19	-163.91	-207.59	-172.04	-125.85	-76.43	-27.16	25.20	63.82	105.53	147.09	188.80	230.37	257.68	299.24	340.95

CASE 1 TASMANIA Sensitivity Fully Manned (Continued)

						PRODUCTION		
YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	82.93	82.93	82.93	68.24	53.75	43.88	34.22	29.39
LESS								
Expenditure								
Capital Costs	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	65.53	54.78	68.13	53.69	38.95	29.33	19.42	-0.56
Undeducted Expendature	-4525.15	-5708.32	-7236.52	-9175.54	-11675.97	-14895.39	-19028.55	-24331.69
Accum. Net Receipts	-4459.62	-5653.53	-7168.39	-9121.85	-11637.02	-14866.06	-19009.13	-24332.24
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	82.93	82.93	82.93	68.24	53.75	43.88	34.22	29.39
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.49								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	68.13	68.38	68.13	53.69	38.95	29.33	19.42	14.84
Tax % 39.00	26.57	26.67	26.57	20.94	15.19	11.44	7.57	5.79
CASH FLOW								
Gas and Liquid Revenue	82.93	82.93	82.93	68.24	53.75	43.88	34.22	29.39
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	26.57	26.67	26.57	20.94	15.19	11.44	7.57	5.79
Total Capital	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Cash Flow	38.96	28.11	41.56	32.75	23.76	17.89	11.85	-6.35
Cum Cash Flow	379.92	408.03	449.59	482.34	506.10	523.99	535.84	529.49

IRR %	10.00	15.00	20.00
NPV $(Millions)	44.53	0.01	-15.19
IRR (CALC) %	15.00		

472284

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 1 TASMANIA Sensitivity Unmanned

CAPITAL	$M	258.19
RATE GAS	$/GJ.	$2.90
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	15.00

		DEVELOPMENT				PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.13												3.40		
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.29	24.40	8.94													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$2.90				$2.90	$2.90	$2.90	$2.90	$2.90	$2.90	$2.90	$2.90	$2.90	$2.90	$2.90	$2.90	$2.90
Natural Gas Revenue						34.78	40.57	43.47	43.47	46.37	46.37	49.27	49.27	49.27	49.27	49.27	49.27	49.27
Sales Liquid Throughput BBLS/Y x 1000						750.00	870.00	940.00	940.00	1000.00	1000.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						15.75	18.27	19.74	19.74	21.00	21.00	22.26	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						50.526	58.842	63.21	63.21	67.368	67.368	71.526	71.526	71.526	71.526	71.526	71.526	71.526

CASE 1 TASMANIA Sensitivity Unmanned (Continued)

												PRODUCTION		
YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform and Pipeline Fabrication						2.60	2.60							66.63
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														43.63
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40	258.19
OPERATING COSTS														
Start Up														0.50
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	39.90
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	25.41
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	97.08
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$2.90				2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90
Natural Gas Revenue						49.27	49.27	49.27	40.57	31.88	26.08	20.29	17.39	883.89
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19040.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	399.84
TOTAL REVENUE						71.526	71.526	71.526	58.842	46.368	37.842	29.526	25.368	1283.73

CASE 1 TASMANIA Sensitivity Unmanned (Continued)

			DEVELOPMENT									PRODUCTION						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						50.53	58.84	63.21	63.21	67.37	67.37	71.53	71.53	71.53	71.53	71.53	71.53	71.53
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
Net Annual Receipts	-10.00	-2.90	-50.29	-100.72	-43.68	40.95	54.11	58.73	58.48	62.89	62.64	67.05	66.80	67.05	66.80	52.65	66.80	67.05
Undeducted Expendature	0.00	-34.36	-47.69	-125.42	-289.46	-426.41	-493.40	-562.29	-644.56	-750.18	-879.73	-1045.88	-1252.90	-1518.22	-1857.50	-2292.10	-2866.50	-3583.62
Accum. Net Receipts	-10.00	-37.26	-97.98	-226.14	-333.14	-385.47	-439.29	-503.56	-586.08	-687.29	-817.09	-978.83	-1186.11	-1451.17	-1790.70	-2239.45	-2799.71	-3516.58
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						50.53	58.84	63.21	63.21	67.37	67.37	71.53	71.53	71.53	71.53	71.53	71.53	71.53
LESS																		
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
Depreciation on : 183.49						34.86	34.86	34.86	34.86	34.86								
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						10.68	19.25	23.87	23.62	28.02	62.64	67.05	66.80	67.05	66.80	67.05	66.80	67.05
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	4.17	7.51	9.31	9.21	10.93	24.43	26.15	26.05	26.15	26.05	26.15	26.05	26.15
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	50.53	58.84	63.21	63.21	67.37	67.37	71.53	71.53	71.53	71.53	71.53	71.53	71.53
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	4.17	7.51	9.31	9.21	10.93	24.43	26.15	26.05	26.15	26.05	26.15	26.05	26.15
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Cash Flow	-10.00	-2.90	-50.29	-100.72	-43.68	36.78	46.60	49.42	49.27	51.96	38.21	40.90	40.75	40.90	40.75	26.50	40.75	40.90
Cum Cash Flow	-10.00	-12.90	-63.19	-163.91	-207.59	-170.81	-124.21	-74.78	-25.51	26.44	64.65	105.55	146.30	187.20	227.94	254.44	295.18	336.08

CASE 1 TASMANIA Sensitivity Unmanned (Continued)

							PRODUCTION	
YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	71.53	71.53	71.53	58.84	46.37	37.84	29.53	25.37
LESS								
Expenditure								
Capital Costs	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Operating Costs	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
Net Annual Receipts	64.20	53.45	66.80	54.36	41.64	33.36	24.80	5.49
Undeducted Expendature	-4501.22	-5679.39	-7201.21	-9132.05	-11619.44	-14819.58	-18926.36	-24194.00
Accum. Net Receipts	-4437.02	-5625.94	-7134.41	-9077.68	-11577.80	-14786.22	-18901.56	-24188.51
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	71.53	71.53	71.53	58.84	46.37	37.84	29.53	25.37
LESS								
Total Operating Costs	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
Depreciation on : 183.49								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	66.80	67.05	66.80	54.36	41.64	33.36	24.80	20.89
Tax % 39.00	26.05	26.15	26.05	21.20	16.24	13.01	9.67	8.15
CASH FLOW								
Gas and Liquid Revenue	71.53	71.53	71.53	58.84	46.37	37.84	29.53	25.37
LESS								
Total Operating Costs	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	26.05	26.15	26.05	21.20	16.24	13.01	9.67	8.15
Total Capital	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Cash Flow	38.15	27.30	40.75	33.16	25.40	20.35	15.13	-2.66
Cum Cash Flow	374.23	401.53	442.27	475.43	500.83	521.18	536.31	533.65

IRR %	10.00	15.00	20.00
NPV $(Millions)	44.49	0.01	-15.15
IRR (CALC) %	15.00		

SENSITIVITY (DEPRECIATION SCHEDULE)

VICTORIA AND TASMAINIA

CASE 1

472289

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 1 VICTORIA Sensitivity Case
CAPITAL $M 280.73
RATE GAS $/GJ. $1.26
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 10.00

			DEVELOPMENT									PRODUCTION							
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	16.28						2.60			2.60						63.38
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	23.88														68.88
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.90	24.85	13.64														48.39
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	280.73
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						1.90	1.90	1.90	1.90	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	53.32
Offshore transport						1.21	1.21	1.21	1.21	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	77.74
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	151.65
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$1.26				1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26
Natural Gas Revenue						37.80	37.80	37.80	37.80	37.80	37.80	37.80	37.80	30.24	22.68	15.12	11.34	7.56	389.34
Sales Liquid Throughput BBLS/Y x 1000						1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19270.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						39.27	39.27	39.27	39.27	39.27	39.27	39.27	39.27	31.50	23.52	15.75	11.76	7.98	404.67
TOTAL REVENUE						77.07	77.07	77.07	77.07	77.07	77.07	77.07	77.07	61.74	46.2	30.87	23.1	15.54	794.01

		DEVEL[illegible]T				RODUC												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						77.07	77.07	77.07	77.07	77.07	77.07	77.07	77.07	61.74	46.20	30.87	23.10	15.54
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-10.00	-2.90	-49.90	-103.01	-68.72	67.03	72.28	72.53	72.28	59.86	62.21	41.46	59.61	47.13	31.34	16.26	8.24	-14.07
Undeducted Expendature	0.00	-34.36	-47.69	-124.92	-291.75	-461.40	-504.79	-553.62	-615.79	-695.70	-813.87	-962.12	-1178.45	-1432.12	-1772.78	-2229.04	-2832.36	-3614.88
Accum. Net Receipts	-10.00	-37.26	-97.59	-227.93	-360.47	-394.37	-432.51	-481.09	-543.51	-635.84	-751.66	-920.66	-1118.84	-1384.99	-1741.44	-2212.78	-2824.12	-3628.95
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						77.07	77.07	77.07	77.07	77.07	77.07	77.07	77.07	61.74	46.20	30.87	23.10	15.54
LESS																		
Total Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 190.43						18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09			
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						53.94	54.19	54.44	54.19	44.37	44.12	44.37	44.12	29.04	13.25	16.26	8.24	0.93
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	21.04	21.13	21.23	21.13	17.30	17.21	17.30	17.21	11.33	5.17	6.34	3.21	0.36
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	77.07	77.07	77.07	77.07	77.07	77.07	77.07	77.07	61.74	46.20	30.87	23.10	15.54
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	21.04	21.13	21.23	21.13	17.30	17.21	17.30	17.21	11.33	5.17	6.34	3.21	0.36
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.90	-103.01	-68.72	45.99	51.15	51.30	51.15	42.56	45.00	24.16	42.40	35.80	26.17	9.92	5.03	-14.43
Cum Cash Flow	-10.00	-12.90	-62.80	-165.81	-234.53	-188.54	-137.39	-86.09	-34.95	7.61	52.61	76.77	119.17	154.98	181.15	191.07	196.10	181.66

IRR %	10.00	15.00	20.00
NPV $(Millions)	0.01	-18.65	-23.94
IRR (CALC) %	10.00		

472290

472291

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 1 VICTORIA Sensitivity Case
CAPITAL $M 280.73
RATE GAS $/GJ. $1.97
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 15.00

	DEVELOPMENT					PRODUCTION													
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	16.28						2.60			2.60						63.38
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	23.88														68.88
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.90	24.85	13.64														48.39
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	280.73
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						1.90	1.90	1.90	1.90	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	53.32
Offshore transport						1.21	1.21	1.21	1.21	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	77.74
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	151.65
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$1.97				1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97
Natural Gas Revenue						59.13	59.13	59.13	59.13	59.13	59.13	59.13	59.13	47.30	35.48	23.65	17.74	11.83	609.04
Sales Liquid Throughput BBLS/Y x 1000						1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19270.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						39.27	39.27	39.27	39.27	39.27	39.27	39.27	39.27	31.50	23.52	15.75	11.76	7.98	404.67
TOTAL REVENUE						98.4	98.4	98.4	98.4	98.4	98.4	98.4	98.4	78.804	58.998	39.402	29.499	19.806	1013.709

			DEVEL.. _ T								RODUC.						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						98.40	98.40	98.40	98.40	98.40	98.40	98.40	98.40	78.80	59.00	39.40	29.50	19.81
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-10.00	-2.90	-49.90	-103.01	-68.72	88.36	93.61	93.86	93.61	81.19	83.54	62.79	80.94	64.19	44.14	24.79	14.64	-9.80
Undeducted Expendature	0.00	-34.36	-47.69	-124.92	-291.75	-461.40	-477.49	-491.37	-508.81	-531.46	-576.34	-630.79	-727.03	-827.00	-976.39	-1193.29	-1495.67	-1895.72
Accum. Net Receipts	-10.00	-37.26	-97.59	-227.93	-360.47	-373.04	-383.88	-397.51	-415.20	-450.27	-492.80	-568.00	-646.09	-762.81	-932.25	-1168.49	-1481.03	-1905.53
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						98.40	98.40	98.40	98.40	98.40	98.40	98.40	98.40	78.80	59.00	39.40	29.50	19.81
LESS																		
Total Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 190.43						18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09			
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						75.27	75.52	75.77	75.52	65.70	65.45	65.70	65.45	46.10	26.05	24.79	14.64	5.20
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	29.35	29.45	29.55	29.45	25.62	25.53	25.62	25.53	17.98	10.16	9.67	5.71	2.03
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	98.40	98.40	98.40	98.40	98.40	98.40	98.40	98.40	78.80	59.00	39.40	29.50	19.81
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	29.35	29.45	29.55	29.45	25.62	25.53	25.62	25.53	17.98	10.16	9.67	5.71	2.03
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.90	-103.01	-68.72	59.01	64.16	64.31	64.16	55.57	58.01	37.17	55.41	46.21	33.98	15.12	8.93	-11.83
Cum Cash Flow	-10.00	-12.90	-62.80	-165.81	-234.53	-175.52	-111.37	-47.06	17.10	72.67	130.68	167.85	223.26	269.48	303.46	318.58	327.51	315.68

IRR %	10.00	15.00	20.00
NPV $(Millions)	34.22	-0.02	-13.36
IRR (CALC) %	15.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT

All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 1 VICTORIA Sensitivity Case
CAPITAL $M 280.73
RATE GAS $/GJ. $3.02
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 20.00

			DEVELOPMENT									PRODUCTION							
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	10.0																		10.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	16.28						2.60			2.60						63.38
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	23.88														68.88
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.90	24.85	13.64														48.39
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	280.73
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						1.90	1.90	1.90	1.90	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	53.32
Offshore transport						1.21	1.21	1.21	1.21	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	77.74
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	151.65
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$3.02				3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02
Natural Gas Revenue						90.54	90.54	90.54	90.54	90.54	90.54	90.54	90.54	72.43	54.32	36.22	27.16	18.11	932.56
Sales Liquid Throughput BBLS/Y x 1000						1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19270.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						39.27	39.27	39.27	39.27	39.27	39.27	39.27	39.27	31.50	23.52	15.75	11.76	7.98	404.67
TOTAL REVENUE						129.81	129.81	129.81	129.81	129.81	129.81	129.81	129.81	103.932	77.844	51.966	38.922	26.088	1337.232

	DEVEL					RODUC												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						129.81	129.81	129.81	129.81	129.81	129.81	129.81	129.81	103.93	77.84	51.97	38.92	26.09
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-10.00	-2.90	-49.90	-103.01	-68.72	119.77	125.02	125.27	125.02	112.60	114.95	94.20	112.35	89.32	62.98	37.36	24.06	-3.52
Undeducted Expendature	0.00	-34.36	-47.69	-124.92	-291.75	-461.40	-437.29	-399.70	-351.27	-289.60	-226.56	-142.86	-62.29	0.00	0.00	0.00	0.00	0.00
Accum. Net Receipts	-10.00	-37.26	-97.59	-227.93	-360.47	-341.63	-312.27	-274.43	-226.25	-177.00	-111.61	-48.66	50.06	89.32	62.98	37.36	24.06	-3.52
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.02	35.73	25.19	14.94	9.62	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						129.81	129.81	129.81	129.81	129.81	129.81	129.81	129.81	103.93	77.84	51.97	38.92	26.09
LESS																		
Total Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 190.43						18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09			
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.02	35.73	25.19	14.94	9.62	0.00
Taxable Income						106.68	106.93	107.18	106.93	97.11	96.86	97.11	76.84	35.50	19.70	22.41	14.44	11.48
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	41.60	41.70	41.80	41.70	37.87	37.78	37.87	29.97	13.85	7.68	8.74	5.63	4.48
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	129.81	129.81	129.81	129.81	129.81	129.81	129.81	129.81	103.93	77.84	51.97	38.92	26.09
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.02	35.73	25.19	14.94	9.62	0.00
Tax	0.00	0.00	0.00	0.00	0.00	41.60	41.70	41.80	41.70	37.87	37.78	37.87	29.97	13.85	7.68	8.74	5.63	4.48
Total Capital	10.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-10.00	-2.90	-49.90	-103.01	-68.72	78.17	83.32	83.47	83.32	74.73	77.17	56.33	62.36	39.75	30.11	13.67	8.81	-8.00
Cum Cash Flow	-10.00	-12.90	-62.80	-165.81	-234.53	-156.36	-73.05	10.42	93.74	168.47	245.64	301.97	364.33	404.08	434.19	447.86	456.66	448.67

IRR %	10.00	15.00	20.00
NPV $(Millions)	73.60	22.58	0.01
IRR (CALC) %	20.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472295

JOB NO 3002
CLIENT AMOCO
CASE 1 TASMANIA Sensitivity Case
CAPITAL $M 258.19
RATE GAS $/GJ. $1.89
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 10.00

			DEVELOPMENT									PRODUCTION						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.13												3.40		
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.29	24.40	8.94													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	5.08	5.08	5.08
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	8.10	8.10	8.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$1.89				$1.89	$1.89	$1.89	$1.89	$1.89	$1.89	$1.89	$1.89	$1.89	$1.89	$1.89	$1.89	$1.89
Natural Gas Revenue						22.70	26.49	28.38	28.38	30.27	30.27	32.16	32.16	32.16	32.16	32.16	32.16	32.16
Sales Liquid Throughput BBLS/Y x 1000						750.00	870.00	940.00	940.00	1000.00	1000.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						15.75	18.27	19.74	19.74	21.00	21.00	22.26	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						38.454	44.758	48.12	48.12	51.272	51.272	54.424	54.424	54.424	54.424	54.424	54.424	54.424

DUCTI

472296

YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform						2.60	2.60							66.63
and Pipeline Fabrication														0.00
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														43.63
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40	258.19
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	74.88
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	101.20
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	207.85
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$1.89				1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89
Natural Gas Revenue						32.16	32.16	32.16	26.49	20.81	17.03	13.24	11.35	577.06
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19040.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	399.84
TOTAL REVENUE						54.424	54.424	54.424	44.758	35.302	28.788	22.484	19.332	976.9

			DEVEL									DUCTI						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						38.45	44.76	48.12	48.12	51.27	51.27	54.42	54.42	54.42	54.42	54.42	54.42	54.42
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Net Annual Receipts	-10.00	-2.90	-50.29	-100.72	-43.68	28.87	40.03	43.64	43.39	46.79	46.54	49.94	49.69	49.94	49.69	25.47	39.62	39.87
Undeducted Expendature	0.00	-34.36	-47.69	-125.42	-289.46	-426.41	-508.85	-600.10	-712.26	-856.16	-1035.99	-1266.49	-1557.18	-1929.58	-2405.93	-3015.99	-3827.86	-4848.94
Accum. Net Receipts	-10.00	-37.26	-97.98	-226.14	-333.14	-397.54	-468.82	-556.46	-668.87	-809.36	-989.45	-1216.55	-1507.48	-1879.64	-2356.24	-2990.51	-3788.23	-4809.06
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						38.45	44.76	48.12	48.12	51.27	51.27	54.42	54.42	54.42	54.42	54.42	54.42	54.42
LESS																		
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Depreciation on : 183.49						17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43			
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						16.04	22.60	26.21	25.96	29.36	29.11	32.51	32.26	32.51	32.26	39.87	39.62	39.87
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	6.26	8.81	10.22	10.12	11.45	11.35	12.68	12.58	12.68	12.58	15.55	15.45	15.55
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	38.45	44.76	48.12	48.12	51.27	51.27	54.42	54.42	54.42	54.42	54.42	54.42	54.42
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	6.26	8.81	10.22	10.12	11.45	11.35	12.68	12.58	12.68	12.58	15.55	15.45	15.55
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Cash Flow	-10.00	-2.90	-50.29	-100.72	-43.68	22.62	31.22	33.42	33.27	35.34	35.19	37.26	37.11	37.26	37.11	9.92	24.17	24.32
Cum Cash Flow	-10.00	-12.90	-63.19	-163.91	-207.59	-184.97	-153.76	-120.34	-87.07	-51.73	-16.54	20.72	57.83	95.10	132.21	142.13	166.30	190.63

YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	54.42	54.42	54.42	44.76	35.30	28.79	22.48	19.33
LESS								
Expenditure								
Capital Costs	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	37.02	26.27	39.62	30.21	20.50	14.24	7.68	-10.62
Undeducted Expendature	-6155.60	-7831.78	-9991.05	-12737.82	-16265.75	-20793.91	-26597.99	-34035.59
Accum. Net Receipts	-6118.58	-7805.51	-9951.42	-12707.62	-16245.25	-20779.68	-26590.30	-34046.20
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	54.42	54.42	54.42	44.76	35.30	28.79	22.48	19.33
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.49								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	39.62	39.87	39.62	30.21	20.50	14.24	7.68	4.78
Tax % 39.00	15.45	15.55	15.45	11.78	8.00	5.55	3.00	1.86
CASH FLOW								
Gas and Liquid Revenue	54.42	54.42	54.42	44.76	35.30	28.79	22.48	19.33
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	15.45	15.55	15.45	11.78	8.00	5.55	3.00	1.86
Total Capital	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Cash Flow	21.57	10.72	24.17	18.43	12.51	8.69	4.69	-12.48
Cum Cash Flow	212.20	222.92	247.09	265.52	278.02	286.71	291.40	278.91

IRR %	10.00	15.00	20.00
NPV $(Millions)	-0.01	-22.05	-27.02
IRR (CALC) %	10.00		

SENSITIVITY (DEPRECIATION SCHEDULE AND INFLATED EXPLORATION WELL COST)

VICTORIA AND TASMAINIA

CASE 1

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472300

JOB NO 3002
CLIENT AMOCO
CASE 1 VICTORIA Sensitivity Case 2
CAPITAL $M 300.73
RATE GAS $/GJ. $1.64
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 10.00

	DEVELOPMENT					PRODUCTION													
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	30.0																		30.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	16.28						2.60			2.60						63.38
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	23.88														68.88
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.90	24.85	13.64														48.39
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	30.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	300.73
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						1.90	1.90	1.90	1.90	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	53.32
Offshore transport						1.21	1.21	1.21	1.21	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	77.74
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	151.65
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$1.64				1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64
Natural Gas Revenue						49.14	49.14	49.14	49.14	49.14	49.14	49.14	49.14	39.31	29.48	19.66	14.74	9.83	506.14
Sales Liquid Throughput BBLS/Y x 1000						1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19270.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						39.27	39.27	39.27	39.27	39.27	39.27	39.27	39.27	31.50	23.52	15.75	11.76	7.98	404.67
TOTAL REVENUE						88.41	88.41	88.41	88.41	88.41	88.41	88.41	88.41	70.812	53.004	35.406	26.502	17.808	910.812

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		DEVEL				ODUCT												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						88.41	88.41	88.41	88.41	88.41	88.41	88.41	88.41	70.81	53.00	35.41	26.50	17.81
LESS																		
Expenditure																		
Capital Costs	30.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-30.00	-2.90	-49.90	-103.01	-68.72	78.37	83.62	83.87	83.62	71.20	73.55	52.80	70.95	56.20	38.14	20.80	11.64	-11.80
Undeducted Expendature	0.00	-34.36	-47.69	-124.92	-291.75	-461.40	-490.28	-520.52	-558.92	-608.38	-687.59	-785.97	-938.46	-1110.41	-1349.38	-1678.39	-2121.72	-2700.90
Accum. Net Receipts	-30.00	-37.26	-97.59	-227.93	-360.47	-383.03	-406.66	-436.65	-475.30	-537.18	-614.04	-733.17	-867.51	-1054.21	-1311.24	-1657.59	-2110.08	-2712.70
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						88.41	88.41	88.41	88.41	88.41	88.41	88.41	88.41	70.81	53.00	35.41	26.50	17.81
LESS																		
Total Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 190.43						18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09			
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						65.28	65.53	65.78	65.53	55.71	55.46	55.71	55.46	38.11	20.05	20.80	11.64	3.20
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	25.46	25.56	25.65	25.56	21.73	21.63	21.73	21.63	14.86	7.82	8.11	4.54	1.25
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	88.41	88.41	88.41	88.41	88.41	88.41	88.41	88.41	70.81	53.00	35.41	26.50	17.81
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	25.46	25.56	25.65	25.56	21.73	21.63	21.73	21.63	14.86	7.82	8.11	4.54	1.25
Total Capital	30.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-30.00	-2.90	-49.90	-103.01	-68.72	52.91	58.06	58.22	58.06	49.47	51.92	31.07	49.32	41.34	30.32	12.69	7.10	-13.05
Cum Cash Flow	-30.00	-32.90	-82.80	-185.81	-254.53	-201.62	-143.56	-85.34	-27.28	22.20	74.12	105.19	154.51	195.85	226.18	238.86	245.96	232.91

IRR %	10.00	15.00	20.00
NPV $(Millions)	0.02	-26.13	-34.98
IRR (CALC) %	10.00		

472302

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 1 VICTORIA Sensitivity Case 2
CAPITAL $M 300.73
RATE GAS $/GJ. $2.64
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 15.00

	DEVELOPMENT					PRODUCTION													
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	30.0																		30.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	16.28						2.60			2.60						63.38
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	23.88														68.88
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.90	24.85	13.64														48.39
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	30.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	300.73
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						1.90	1.90	1.90	1.90	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	53.32
Offshore transport						1.21	1.21	1.21	1.21	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	77.74
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	151.65
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$2.64				2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64
Natural Gas Revenue						79.05	79.05	79.05	79.05	79.05	79.05	79.05	79.05	63.24	47.43	31.62	23.72	15.81	814.21
Sales Liquid Throughput BBLS/Y x 1000						1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19270.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						39.27	39.27	39.27	39.27	39.27	39.27	39.27	39.27	31.50	23.52	15.75	11.76	7.98	404.67
TOTAL REVENUE						118.32	118.32	118.32	118.32	118.32	118.32	118.32	118.32	94.74	70.95	47.37	35.475	23.79	1218.885

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			EVEL									ODUCT						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						118.32	118.32	118.32	118.32	118.32	118.32	118.32	118.32	94.74	70.95	47.37	35.48	23.79
LESS																		
Expenditure																		
Capital Costs	30.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-30.00	-2.90	-49.90	-103.01	-68.72	108.28	113.53	113.78	113.53	101.11	103.46	82.71	100.86	80.13	56.09	32.76	20.62	-5.82
Undeducted Expendature	0.00	-34.36	-47.69	-124.92	-291.75	-461.40	-451.99	-433.23	-408.90	-378.07	-354.51	-321.35	-305.46	-261.89	-232.65	-225.99	-247.34	-290.21
Accum. Net Receipts	-30.00	-37.26	-97.59	-227.93	-360.47	-353.12	-338.46	-319.45	-295.37	-276.96	-251.05	-238.64	-204.60	-181.76	-176.56	-193.23	-226.73	-296.03
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						118.32	118.32	118.32	118.32	118.32	118.32	118.32	118.32	94.74	70.95	47.37	35.48	23.79
LESS																		
Total Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 190.43						18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09			
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						95.19	95.44	95.69	95.44	85.62	85.37	85.62	85.37	62.04	38.00	32.76	20.62	9.18
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	37.12	37.22	37.32	37.22	33.39	33.29	33.39	33.29	24.20	14.82	12.78	8.04	3.58
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	118.32	118.32	118.32	118.32	118.32	118.32	118.32	118.32	94.74	70.95	47.37	35.48	23.79
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	37.12	37.22	37.32	37.22	33.39	33.29	33.39	33.29	24.20	14.82	12.78	8.04	3.58
Total Capital	30.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-30.00	-2.90	-49.90	-103.01	-68.72	71.16	76.31	76.46	76.31	67.72	70.17	49.32	67.57	55.93	41.27	19.98	12.58	-9.40
Cum Cash Flow	-30.00	-32.90	-82.80	-185.81	-254.53	-183.37	-107.07	-30.60	45.70	113.42	183.59	232.91	300.47	356.41	397.68	417.66	430.24	420.84

IRR %	10.00	15.00	20.00
NPV $(Millions)	47.98	-0.01	-20.14
IRR (CALC) %	15.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472304

JOB NO 3002
CLIENT AMOCO
CASE 1 VICTORIA Sensitivity Case 2
CAPITAL $M 300.73
RATE GAS $/GJ. $5.07
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 20.00

			DEVELOPMENT									PRODUCTION							
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL
CAPITAL INVESTMENT																			
Exploration Well	30.0																		30.00
Pre-Engr., Investigation		1.00																	1.00
Design, Material, Platform		1.90	40.00	16.28						2.60			2.60						63.38
and Pipeline Fabrication																			0.00
Offshore Installation				45.00	23.88														68.88
Onshore Plant, Marine Base				16.88															16.88
Development Drilling					31.20							21.00							52.20
Insurance, Contingency			9.90	24.85	13.64														48.39
Working Capital						5.00												-5.00	0.00
Platform Removal																		20.00	20.00
Total Capital	30.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00	300.73
OPERATING COSTS																			
Start Up						0.50													0.50
Offshore facility						1.90	1.90	1.90	1.90	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	53.32
Offshore transport						1.21	1.21	1.21	1.21	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	77.74
Onshore plant						0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	7.54
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	11.05
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25		1.50
TOTAL COSTS						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61	151.65
REVENUE																			
Sales Gas Throughput PJ/Y						30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	24.00	18.00	12.00	9.00	6.00	309.00
Gas Selling Price $/GJ		$5.07				5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07
Natural Gas Revenue						151.98	151.98	151.98	151.98	151.98	151.98	151.98	151.98	121.58	91.19	60.79	45.59	30.40	1565.39
Sales Liquid Throughput BBLS/Y x 1000						1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1870.00	1500.00	1120.00	750.00	560.00	380.00	19270.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						39.27	39.27	39.27	39.27	39.27	39.27	39.27	39.27	31.50	23.52	15.75	11.76	7.98	404.67
TOTAL REVENUE						191.25	191.25	191.25	191.25	191.25	191.25	191.25	191.25	153.084	114.708	76.542	57.354	38.376	1970.064

			EVELC									DUCT						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						191.25	191.25	191.25	191.25	191.25	191.25	191.25	191.25	153.08	114.71	76.54	57.35	38.38
LESS																		
Expenditure																		
Capital Costs	30.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Net Annual Receipts	-30.00	-2.90	-49.90	-103.01	-68.72	181.21	186.46	186.71	186.46	174.04	176.39	155.64	173.79	138.47	99.85	61.93	42.49	8.77
Undeducted Expendature	0.00	-34.36	-47.69	-124.92	-291.75	-461.40	-358.64	-220.39	-43.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accum. Net Receipts	-30.00	-37.26	-97.59	-227.93	-360.47	-280.19	-172.18	-33.68	143.34	174.04	176.39	155.64	173.79	138.47	99.85	61.93	42.49	8.77
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.34	69.62	70.56	62.26	69.52	55.39	39.94	24.77	17.00	3.51
TAX SCHEDULE																		
Gas and Liquid Revenue						191.25	191.25	191.25	191.25	191.25	191.25	191.25	191.25	153.08	114.71	76.54	57.35	38.38
LESS																		
Total Operating Costs						5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
Depreciation on : 190.43						18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09	18.09			
RRT						0.00	0.00	0.00	57.34	69.62	70.56	62.26	69.52	55.39	39.94	24.77	17.00	3.51
Taxable Income						168.12	168.37	168.62	111.03	88.93	87.74	96.29	88.78	64.99	41.82	37.16	25.50	20.26
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	65.57	65.66	65.76	43.30	34.68	34.22	37.55	34.63	25.35	16.31	14.49	9.94	7.90
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	191.25	191.25	191.25	191.25	191.25	191.25	191.25	191.25	153.08	114.71	76.54	57.35	38.38
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	5.04	4.79	4.54	4.79	14.61	14.86	14.61	14.86	14.61	14.86	14.61	14.86	14.61
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.34	69.62	70.56	62.26	69.52	55.39	39.94	24.77	17.00	3.51
Tax	0.00	0.00	0.00	0.00	0.00	65.57	65.66	65.76	43.30	34.68	34.22	37.55	34.63	25.35	16.31	14.49	9.94	7.90
Total Capital	30.00	2.90	49.90	103.01	68.72	5.00	0.00	0.00	0.00	2.60	0.00	21.00	2.60	0.00	0.00	0.00	0.00	15.00
Cash Flow	-30.00	-2.90	-49.90	-103.01	-68.72	115.64	120.80	120.95	85.82	69.74	71.61	55.83	69.65	57.74	43.60	22.67	15.55	-2.64
Cum Cash Flow	-30.00	-32.90	-82.80	-185.81	-254.53	-138.89	-18.09	102.86	188.68	258.42	330.03	385.86	455.51	513.25	556.85	579.51	595.07	592.43

IRR %	10.00	15.00	20.00
NPV $(Millions)	102.70	32.71	0.00
IRR (CALC) %	20.00		

472305

JOB NO 3002
CLIENT AMOCO
CASE 1 TASMANIA Sensitivity Case 2

CAPITAL	$M	278.19
RATE GAS	$/GJ.	$2.43
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	10.00

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472306

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	30.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.13												3.40		
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.29	24.40	8.94													
Working Capital						4.60												
Platform Removal																		
Total Capital	30.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	5.08	5.08	5.08
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	8.10	8.10	8.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$2.43				$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43
Natural Gas Revenue						29.18	34.05	36.48	36.48	38.91	38.91	41.34	41.34	41.34	41.34	41.34	41.34	41.34
Sales Liquid Throughput BBLS/Y x 1000						750.00	870.00	940.00	940.00	1000.00	1000.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						15.75	18.27	19.74	19.74	21.00	21.00	22.26	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						44.934	52.318	56.22	56.22	59.912	59.912	63.604	63.604	63.604	63.604	63.604	63.604	63.604

YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														30.00
Pre-Engr., Investigation														1.00
Design, Material, Platform						2.60	2.60							66.63
and Pipeline Fabrication														0.00
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														43.63
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40	278.19
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	74.88
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	101.20
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	207.85
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$2.43				2.43	2.43	2.43	2.43	2.43	2.43	2.43	2.43	2.43
Natural Gas Revenue						41.34	41.34	41.34	34.05	26.75	21.89	17.02	14.59	741.76
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19040.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	399.84
TOTAL REVENUE						63.604	63.604	63.604	52.318	41.242	33.648	26.264	22.572	1141.6

472308

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 1 TASMANIA Sensitivity Case
CAPITAL $M 258.19
RATE GAS $/GJ. $3.23
RATE LIQUID $/BBL. $21.00
RIT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 15.00

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.13												3.40		
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.29	24.40	8.94													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	5.08	5.08	5.08
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	8.10	8.10	8.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$3.23				$3.23	$3.23	$3.23	$3.23	$3.23	$3.23	$3.23	$3.23	$3.23	$3.23	$3.23	$3.23	$3.23
Natural Gas Revenue						38.78	45.25	48.48	48.48	51.71	51.71	54.94	54.94	54.94	54.94	54.94	54.94	54.94
Sales Liquid Throughput BBLS/Y x 1000						750.00	870.00	940.00	940.00	1000.00	1000.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						15.75	18.27	19.74	19.74	21.00	21.00	22.26	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						54.534	63.518	68.22	68.22	72.712	72.712	77.204	77.204	77.204	77.204	77.204	77.204	77.204

DUCTI

YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform						2.60	2.60							66.63
and Pipeline Fabrication														0.00
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														43.63
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40	258.19
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	74.88
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	101.20
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	207.85
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$3.23				3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23
Natural Gas Revenue						54.94	54.94	54.94	45.25	35.55	29.09	22.62	19.39	985.76
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19040.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	399.84
TOTAL REVENUE						77.204	77.204	77.204	63.518	50.042	40.848	31.864	27.372	1385.6

			DEVEL									DUCTI						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						54.53	63.52	68.22	68.22	72.71	72.71	77.20	77.20	77.20	77.20	77.20	77.20	77.20
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Net Annual Receipts	-10.00	-2.90	-50.29	-100.72	-43.68	44.95	58.79	63.74	63.49	68.23	67.98	72.72	72.47	72.72	72.47	48.25	62.40	62.65
Undeducted Expendature	0.00	-34.36	-47.69	-125.42	-289.46	-426.41	-488.27	-549.74	-622.08	-714.99	-827.85	-972.63	-1151.88	-1381.64	-1675.41	-2051.76	-2564.49	-3202.67
Accum. Net Receipts	-10.00	-37.26	-97.98	-226.14	-333.14	-381.46	-429.48	-486.00	-558.59	-646.76	-759.87	-899.91	-1079.41	-1308.92	-1602.94	-2003.51	-2502.09	-3140.02
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						54.53	63.52	68.22	68.22	72.71	72.71	77.20	77.20	77.20	77.20	77.20	77.20	77.20
LESS																		
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Depreciation on : 183.49						17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43			
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						32.12	41.36	46.31	46.06	50.80	50.55	55.29	55.04	55.29	55.04	62.65	62.40	62.65
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	12.53	16.13	18.06	17.96	19.81	19.71	21.56	21.47	21.56	21.47	24.44	24.34	24.44
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	54.53	63.52	68.22	68.22	72.71	72.71	77.20	77.20	77.20	77.20	77.20	77.20	77.20
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	12.53	16.13	18.06	17.96	19.81	19.71	21.56	21.47	21.56	21.47	24.44	24.34	24.44
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Cash Flow	-10.00	-2.90	-50.29	-100.72	-43.68	32.43	42.66	45.68	45.53	48.42	48.27	51.16	51.01	51.16	51.01	23.82	38.07	38.22
Cum Cash Flow	-10.00	-12.90	-63.19	-163.91	-207.59	-175.16	-132.50	-86.83	-41.30	7.12	55.39	106.55	157.56	208.72	259.72	283.54	321.61	359.83

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YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	77.20	77.20	77.20	63.52	50.04	40.85	31.86	27.37
LESS								
Expenditure								
Capital Costs	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	59.80	49.05	62.40	48.97	35.24	26.30	17.06	-2.58
Undeducted Expendature	-4019.22	-5068.06	-6424.33	-8143.26	-10360.69	-13216.58	-16883.56	-21589.11
Accum. Net Receipts	-3959.42	-5019.00	-6361.92	-8094.29	-10325.45	-13190.28	-16866.50	-21591.69
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	77.20	77.20	77.20	63.52	50.04	40.85	31.86	27.37
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.49								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	62.40	62.65	62.40	48.97	35.24	26.30	17.06	12.82
Tax % 39.00	24.34	24.44	24.34	19.10	13.74	10.26	6.65	5.00
CASH FLOW								
Gas and Liquid Revenue	77.20	77.20	77.20	63.52	50.04	40.85	31.86	27.37
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	24.34	24.44	24.34	19.10	13.74	10.26	6.65	5.00
Total Capital	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Cash Flow	35.47	24.62	38.07	29.87	21.50	16.04	10.41	-7.58
Cum Cash Flow	395.29	419.91	457.98	487.85	509.35	525.39	535.80	528.22

IRR %	10.00	15.00	20.00
NPV $(Millions)	45.06	-0.02	-15.46
IRR (CALC) %	15.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

JOB NO 3002
CLIENT AMOCO
CASE 1 TASMANIA Sensitivity Case
CAPITAL $M 258.19
RATE GAS $/GJ. $5.02
RATE LIQUID $/BBL. $21.00
RTT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 20.00

		DEVELOPMENT				PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	10.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.13												3.40		
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.29	24.40	8.94													
Working Capital						4.60												
Platform Removal																		
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	5.08	5.08	5.08
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	8.10	8.10	8.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$5.02				$5.02	$5.02	$5.02	$5.02	$5.02	$5.02	$5.02	$5.02	$5.02	$5.02	$5.02	$5.02	$5.02
Natural Gas Revenue						60.29	70.34	75.36	75.36	80.38	80.38	85.41	85.41	85.41	85.41	85.41	85.41	85.41
Sales Liquid Throughput BBLS/Y x 1000						750.00	870.00	940.00	940.00	1000.00	1000.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						15.75	18.27	19.74	19.74	21.00	21.00	22.26	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						76.038	88.606	95.1	95.1	101.384	101.384	107.668	107.668	107.668	107.668	107.668	107.668	107.668

YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														10.00
Pre-Engr., Investigation														1.00
Design, Material, Platform						2.60	2.60							66.63
and Pipeline Fabrication														0.00
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														43.63
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40	258.19
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	74.88
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	101.20
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	207.85
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$5.02				5.02	5.02	5.02	5.02	5.02	5.02	5.02	5.02	5.02
Natural Gas Revenue						85.41	85.41	85.41	70.34	55.26	45.22	35.17	30.14	1532.32
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19040.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	399.84
TOTAL REVENUE						107.668	107.668	107.668	88.606	69.754	56.976	44.408	38.124	1932.16

			DEVEL									DUCTI						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						76.04	88.61	95.10	95.10	101.38	101.38	107.67	107.67	107.67	107.67	107.67	107.67	107.67
LESS																		
Expenditure																		
Capital Costs	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Net Annual Receipts	-10.00	-2.90	-50.29	-100.72	-43.68	66.46	83.88	90.62	90.37	96.90	96.65	103.19	102.94	103.19	102.94	78.72	92.87	93.12
Undeducted Expendature	0.00	-34.36	-47.69	-125.42	-289.46	-426.41	-460.74	-482.39	-501.47	-526.21	-549.51	-579.65	-609.87	-648.88	-698.48	-762.29	-874.98	-1001.10
Accum. Net Receipts	-10.00	-37.26	-97.98	-226.14	-333.14	-359.96	-376.87	-391.77	-411.10	-429.30	-452.85	-476.46	-506.93	-545.69	-595.54	-683.58	-782.11	-907.98
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						76.04	88.61	95.10	95.10	101.38	101.38	107.67	107.67	107.67	107.67	107.67	107.67	107.67
LESS																		
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Depreciation on : . 183.49						17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43			
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						53.63	66.44	73.19	72.94	79.47	79.22	85.76	85.51	85.76	85.51	93.12	92.87	93.12
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	20.91	25.91	28.54	28.45	30.99	30.90	33.45	33.35	33.45	33.35	36.32	36.22	36.32
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	76.04	88.61	95.10	95.10	101.38	101.38	107.67	107.67	107.67	107.67	107.67	107.67	107.67
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	20.91	25.91	28.54	28.45	30.99	30.90	33.45	33.35	33.45	33.35	36.32	36.22	36.32
Total Capital	10.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Cash Flow	-10.00	-2.90	-50.29	-100.72	-43.68	45.54	57.96	62.08	61.92	65.91	65.76	69.74	69.59	69.74	69.59	42.40	56.65	56.80
Cum Cash Flow	-10.00	-12.90	-63.19	-163.91	-207.59	-162.05	-104.08	-42.01	19.92	85.83	151.58	221.33	290.92	360.66	430.25	472.65	529.30	586.10

YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	107.67	107.67	107.67	88.61	69.75	56.98	44.41	38.12
LESS								
Expenditure								
Capital Costs	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	90.27	79.52	92.87	74.06	54.95	42.43	29.61	8.17
Undeducted Expendature	-1162.22	-1372.10	-1654.50	-1998.89	-2463.79	-3083.31	-3892.33	-4944.28
Accum. Net Receipts	-1071.95	-1292.58	-1561.63	-1924.83	-2408.83	-3040.88	-3862.72	-4936.11
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	107.67	107.67	107.67	88.61	69.75	56.98	44.41	38.12
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.49								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	92.87	93.12	92.87	74.06	54.95	42.43	29.61	23.57
Tax % 39.00	36.22	36.32	36.22	28.88	21.43	16.55	11.55	9.19
CASH FLOW								
Gas and Liquid Revenue	107.67	107.67	107.67	88.61	69.75	56.98	44.41	38.12
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	36.22	36.32	36.22	28.88	21.43	16.55	11.55	9.19
Total Capital	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Cash Flow	54.05	43.20	56.65	45.17	33.52	25.88	18.06	-1.02
Cum Cash Flow	640.15	683.36	740.01	785.18	818.70	844.58	862.64	861.62

IRR %	10.00	15.00	20.00
NPV $(Millions)	105.32	29.43	-0.01
IRR (CALC) %	20.00		

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			EVELC									UCTI						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						44.93	52.32	56.22	56.22	59.91	59.91	63.60	63.60	63.60	63.60	63.60	63.60	63.60
LESS																		
Expenditure																		
Capital Costs	30.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Net Annual Receipts	-30.00	-2.90	-50.29	-100.72	-43.68	35.35	47.59	51.74	51.49	55.43	55.18	59.12	58.87	59.12	58.87	34.65	48.80	49.05
Undeducted Expendature	0.00	-34.36	-47.69	-125.42	-289.46	-426.41	-500.56	-579.80	-675.92	-799.27	-952.11	-1148.07	-1393.85	-1708.77	-2111.55	-2627.42	-3318.74	-4185.52
Accum. Net Receipts	-30.00	-37.26	-97.98	-226.14	-333.14	-391.06	-452.97	-528.06	-624.43	-743.84	-896.93	-1088.95	-1334.98	-1649.65	-2052.67	-2592.77	-3269.94	-4136.46
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						44.93	52.32	56.22	56.22	59.91	59.91	63.60	63.60	63.60	63.60	63.60	63.60	63.60
LESS																		
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Depreciation on : 183.49						17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43			
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						22.52	30.16	34.31	34.06	38.00	37.75	41.69	41.44	41.69	41.44	49.05	48.80	49.05
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	8.78	11.76	13.38	13.28	14.82	14.72	16.26	16.16	16.26	16.16	19.13	19.03	19.13
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	44.93	52.32	56.22	56.22	59.91	59.91	63.60	63.60	63.60	63.60	63.60	63.60	63.60
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	8.78	11.76	13.38	13.28	14.82	14.72	16.26	16.16	16.26	16.16	19.13	19.03	19.13
Total Capital	30.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Cash Flow	-30.00	-2.90	-50.29	-100.72	-43.68	26.57	35.83	38.36	38.21	40.61	40.46	42.86	42.71	42.86	42.71	15.52	29.77	29.92
Cum Cash Flow	-30.00	-32.90	-83.19	-183.91	-227.59	-201.02	-165.19	-126.83	-88.63	-48.01	-7.55	35.31	78.02	120.88	163.60	179.12	208.89	238.81

YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	63.60	63.60	63.60	52.32	41.24	33.65	26.26	22.57
LESS								
Expenditure								
Capital Costs	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	46.20	35.45	48.80	37.77	26.44	19.10	11.46	-7.38
Undeducted Expendature	-5294.67	-6718.04	-8553.71	-10886.28	-13886.10	-17740.36	-22683.22	-29019.84
Accum. Net Receipts	-5248.47	-6682.59	-8504.91	-10848.51	-13859.66	-17721.26	-22671.75	-29027.22
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	63.60	63.60	63.60	52.32	41.24	33.65	26.26	22.57
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.49								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	48.80	49.05	48.80	37.77	26.44	19.10	11.46	8.02
Tax % 39.00	19.03	19.13	19.03	14.73	10.31	7.45	4.47	3.13
CASH FLOW								
Gas and Liquid Revenue	63.60	63.60	63.60	52.32	41.24	33.65	26.26	22.57
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	19.03	19.13	19.03	14.73	10.31	7.45	4.47	3.13
Total Capital	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Cash Flow	27.17	16.32	29.77	23.04	16.13	11.65	6.99	-10.51
Cum Cash Flow	265.98	282.31	312.08	335.11	351.24	362.89	369.89	359.38

IRR %	10.00	15.00	20.00
NPV $(Millions)	-0.03	-30.56	-39.03
IRR (CALC) %	10.00		

JOB NO 3002
CLIENT AMOCO
CASE 1 TASMANIA Sensitivity Case 2
CAPITAL $M 278.19
RATE GAS $/GJ. $4.29
RATE LIQUID $/BBL. $21.00
RIT % 40.00
THRESHOLD RATE % 28.00
TAX % 39.00
IRR % 15.00

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472318

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	30.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.13												3.40		
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.29	24.40	8.94													
Working Capital						4.60												
Platform Removal																		
Total Capital	30.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	5.08	5.08	5.08
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	8.10	8.10	8.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$4.29				$4.29	$4.29	$4.29	$4.29	$4.29	$4.29	$4.29	$4.29	$4.29	$4.29	$4.29	$4.29	$4.29
Natural Gas Revenue						51.48	60.06	64.35	64.35	68.64	68.64	72.93	72.93	72.93	72.93	72.93	72.93	72.93
Sales Liquid Throughput BBLS/Y x 1000						750.00	870.00	940.00	940.00	1000.00	1000.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						15.75	18.27	19.74	19.74	21.00	21.00	22.26	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						67.23	78.33	84.09	84.09	89.64	89.64	95.19	95.19	95.19	95.19	95.19	95.19	95.19

YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														30.00
Pre-Engr., Investigation														1.00
Design, Material, Platform						2.60	2.60							66.63
and Pipeline Fabrication														0.00
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														43.63
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40	278.19
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	74.88
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	101.20
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	207.85
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$4.29				4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29
Natural Gas Revenue						72.93	72.93	72.93	60.06	47.19	38.61	30.03	25.74	1308.45
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19040.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	399.84
TOTAL REVENUE						95.19	95.19	95.19	78.33	61.68	50.37	39.27	33.72	1708.29

			DEVELO									UCTIC						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						67.23	78.33	84.09	84.09	89.64	89.64	95.19	95.19	95.19	95.19	95.19	95.19	95.19
LESS																		
Expenditure																		
Capital Costs	30.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Net Annual Receipts	-30.00	-2.90	-50.29	-100.72	-43.68	57.65	73.60	79.61	79.36	85.16	84.91	90.71	90.46	90.71	90.46	66.24	80.39	80.64
Undeducted Expendature	0.00	-34.36	-47.69	-125.42	-289.46	-426.41	-472.02	-509.98	-550.87	-603.53	-663.52	-740.61	-831.88	-949.02	-1098.63	-1290.46	-1567.00	-1902.86
Accum. Net Receipts	-30.00	-37.26	-97.98	-226.14	-333.14	-368.76	-398.42	-430.37	-471.51	-518.37	-578.61	-649.90	-741.42	-858.31	-1008.17	-1224.22	-1486.61	-1822.22
RRT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE																		
Gas and Liquid Revenue						67.23	78.33	84.09	84.09	89.64	89.64	95.19	95.19	95.19	95.19	95.19	95.19	95.19
LESS																		
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Depreciation on : 183.49						17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43			
RRT						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income						44.82	56.17	62.18	61.93	67.73	67.48	73.28	73.03	73.28	73.03	80.64	80.39	80.64
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	17.48	21.91	24.25	24.15	26.41	26.32	28.58	28.48	28.58	28.48	31.45	31.35	31.45
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	67.23	78.33	84.09	84.09	89.64	89.64	95.19	95.19	95.19	95.19	95.19	95.19	95.19
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00	17.48	21.91	24.25	24.15	26.41	26.32	28.58	28.48	28.58	28.48	31.45	31.35	31.45
Total Capital	30.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Cash Flow	-30.00	-2.90	-50.29	-100.72	-43.68	40.17	51.69	55.36	55.21	58.75	58.59	62.13	61.98	62.13	61.98	34.79	49.04	49.19
Cum Cash Flow	-30.00	-32.90	-83.19	-183.91	-227.59	-187.42	-135.72	-80.36	-25.16	33.59	92.18	154.31	216.29	278.42	340.40	375.19	424.23	473.42

472321

YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	95.19	95.19	95.19	78.33	61.68	50.37	39.27	33.72
LESS								
Expenditure								
Capital Costs	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	77.79	67.04	80.39	63.78	46.88	35.82	24.47	3.77
Undeducted Expendature	-2332.44	-2885.96	-3608.21	-4515.61	-5698.35	-7233.88	-9213.51	-11761.97
Accum. Net Receipts	-2254.65	-2818.92	-3527.82	-4451.83	-5651.47	-7198.06	-9189.04	-11758.20
RTT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TAX SCHEDULE								
Gas and Liquid Revenue	95.19	95.19	95.19	78.33	61.68	50.37	39.27	33.72
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.49								
RRT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income	80.39	80.64	80.39	63.78	46.88	35.82	24.47	19.17
Tax % 39.00	31.35	31.45	31.35	24.87	18.28	13.97	9.54	7.48
CASH FLOW								
Gas and Liquid Revenue	95.19	95.19	95.19	78.33	61.68	50.37	39.27	33.72
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax	31.35	31.45	31.35	24.87	18.28	13.97	9.54	7.48
Total Capital	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Cash Flow	46.44	35.59	49.04	38.91	28.60	21.85	14.93	-3.71
Cum Cash Flow	519.86	555.45	604.49	643.39	671.99	693.84	708.77	705.06

IRR %	10.00	15.00	20.00
NPV $(Millions)	62.45	-0.02	-23.01
IRR (CALC) %	15.00		

FINANCIAL ANALYSIS YOLLA GAS FIELD DEVELOPMENT
All Costs Aust. Dollars Millions.
(First Quarter 1989)

472322

JOB NO 3002
CLIENT AMOCO
CASE 1 TASMANIA Sensitivity Case 2

CAPITAL	$M	278.19
RATE GAS	$/GJ.	$8.49
RATE LIQUID	$/BBL.	$21.00
RTT	%	40.00
THRESHOLD RATE	%	28.00
TAX	%	39.00
IRR	%	20.00

	DEVELOPMENT					PRODUCTION												
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
CAPITAL INVESTMENT																		
Exploration Well	30.0																	
Pre-Engr., Investigation		1.00																
Design, Material, Platform and Pipeline Fabrication		1.90	40.00	16.13												3.40		
Offshore Installation				45.00	23.54													
Onshore Plant, Marine Base				15.19														
Development Drilling					11.20											11.00		
Insurance, Contingency			10.29	24.40	8.94													
Working Capital						4.60												
Platform Removal																		
Total Capital	30.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
OPERATING COSTS																		
Start Up						0.50												
Offshore facility						1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	5.08	5.08	5.08
Offshore transport						1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	1.21	8.10	8.10	8.10
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Well Workover							0.25		0.25		0.25		0.25		0.25		0.25	
TOTAL COSTS						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
REVENUE																		
Sales Gas Throughput PJ/Y						12.00	14.00	15.00	15.00	16.00	16.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Gas Selling Price $/GJ		$8.49				$8.49	$8.49	$8.49	$8.49	$8.49	$8.49	$8.49	$8.49	$8.49	$8.49	$8.49	$8.49	$8.49
Natural Gas Revenue						101.88	118.86	127.35	127.35	135.84	135.84	144.33	144.33	144.33	144.33	144.33	144.33	144.33
Sales Liquid Throughput BBLS/Y x 1000						750.00	870.00	940.00	940.00	1000.00	1000.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00	1060.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						15.75	18.27	19.74	19.74	21.00	21.00	22.26	22.26	22.26	22.26	22.26	22.26	22.26
TOTAL REVENUE						117.63	137.13	147.09	147.09	156.84	156.84	166.59	166.59	166.59	166.59	166.59	166.59	166.59

CASE TASK Sens tv C ntin DUCTI

472323

YEAR						14	15	16	17	18	19	20	21	TOTAL
CAPITAL INVESTMENT														
Exploration Well														30.00
Pre-Engr., Investigation														1.00
Design, Material, Platform						2.60	2.60							66.63
and Pipeline Fabrication														0.00
Offshore Installation														68.54
Onshore Plant, Marine Base														15.19
Development Drilling							11.00							33.20
Insurance, Contingency														43.63
Working Capital													-4.60	0.00
Platform Removal													20.00	20.00
Total Capital	0.00	0.00	0.00	0.00	0.00	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40	278.19
OPERATING COSTS														
Start Up														0.50
Offshore facility						5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	74.88
Offshore transport						8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	101.20
Onshore plant						0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	10.92
Insurance Overheads						0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	17.85
Well Workover						0.25		0.25		0.25		0.25		2.50
TOTAL COSTS						14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55	207.85
REVENUE														
Sales Gas Throughput PJ/Y						17.00	17.00	17.00	14.00	11.00	9.00	7.00	6.00	305.00
Gas Selling Price $/GJ		$8.49				8.49	8.49	8.49	8.49	8.49	8.49	8.49	8.49	8.49
Natural Gas Revenue						144.33	144.33	144.33	118.86	93.39	76.41	59.43	50.94	2589.45
Sales Liquid Throughput BBLS/Y x 1000						1060.00	1060.00	1060.00	870.00	690.00	560.00	440.00	380.00	19040.00
Liquid Selling Price		$21.00				21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00	21.00
Liquid Revenue						22.26	22.26	22.26	18.27	14.49	11.76	9.24	7.98	399.84
TOTAL REVENUE						166.59	166.59	166.59	137.13	107.88	88.17	68.67	58.92	2989.29

			DEVEL									UCTI						
YEAR	-5	1	2	3	4	1	2	3	4	5	6	7	8	9	10	11	12	13
RESOURCE RENT TAX																		
Receipts						117.63	137.13	147.09	147.09	156.84	156.84	166.59	166.59	166.59	166.59	166.59	166.59	166.59
LESS																		
Expenditure																		
Capital Costs	30.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Net Annual Receipts	-30.00	-2.90	-50.29	-100.72	-43.68	108.05	132.40	142.61	142.36	152.36	152.11	162.11	161.86	162.11	161.86	137.64	151.79	152.04
Undeducted Expendature	0.00	-34.36	-47.69	-125.42	-289.46	-426.41	-407.51	-352.14	-268.19	-161.07	-11.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accum. Net Receipts	-30.00	-37.26	-97.98	-226.14	-333.14	-318.36	-275.11	-209.53	-125.83	-8.71	140.96	162.11	161.86	162.11	161.86	137.64	151.79	152.04
RIT % 40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.39	64.84	64.74	64.84	64.74	55.06	60.72	60.82
TAX SCHEDULE																		
Gas and Liquid Revenue						117.63	137.13	147.09	147.09	156.84	156.84	166.59	166.59	166.59	166.59	166.59	166.59	166.59
LESS																		
Total Operating Costs						4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
Depreciation on : 183.49						17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43	17.43			
RRT						0.00	0.00	0.00	0.00	0.00	56.39	64.84	64.74	64.84	64.74	55.06	60.72	60.82
Taxable Income						95.22	114.97	125.18	124.93	134.93	78.29	79.83	79.68	79.83	79.68	96.98	91.07	91.22
Tax % 39.00	0.00	0.00	0.00	0.00	0.00	37.14	44.84	48.82	48.72	52.62	30.53	31.14	31.08	31.14	31.08	37.82	35.52	35.58
CASH FLOW																		
Gas and Liquid Revenue	0.00	0.00	0.00	0.00	0.00	117.63	137.13	147.09	147.09	156.84	156.84	166.59	166.59	166.59	166.59	166.59	166.59	166.59
LESS																		
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	4.98	4.73	4.48	4.73	4.48	4.73	4.48	4.73	4.48	4.73	14.55	14.80	14.55
RIT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.39	64.84	64.74	64.84	64.74	55.06	60.72	60.82
Tax	0.00	0.00	0.00	0.00	0.00	37.14	44.84	48.82	48.72	52.62	30.53	31.14	31.08	31.14	31.08	37.82	35.52	35.58
Total Capital	30.00	2.90	50.29	100.72	43.68	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40	0.00	0.00
Cash Flow	-30.00	-2.90	-50.29	-100.72	-43.68	70.91	87.56	93.79	93.64	99.74	65.19	66.13	66.04	66.13	66.04	44.76	55.56	55.65
Cum Cash Flow	-30.00	-32.90	-83.19	-183.91	-227.59	-156.68	-69.11	24.68	118.32	218.05	283.24	349.37	415.41	481.54	547.58	592.34	647.90	703.54

YEAR	14	15	16	17	18	19	20	21
RESOURCE RENT TAX								
Receipts	166.59	166.59	166.59	137.13	107.88	88.17	68.67	58.92
LESS								
Expenditure								
Capital Costs	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Net Annual Receipts	149.19	138.44	151.79	122.58	93.08	73.62	53.87	28.97
Undeducted Expendature	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accum. Net Receipts	149.19	138.44	151.79	122.58	93.08	73.62	53.87	28.97
RTT % 40.00	59.68	55.38	60.72	49.03	37.23	29.45	21.55	11.59
TAX SCHEDULE								
Gas and Liquid Revenue	166.59	166.59	166.59	137.13	107.88	88.17	68.67	58.92
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
Depreciation on : 183.49								
RRT	59.68	55.38	60.72	49.03	37.23	29.45	21.55	11.59
Taxable Income	92.11	96.66	91.07	73.55	55.85	44.17	32.32	32.78
Tax % 39.00	35.92	37.70	35.52	28.68	21.78	17.23	12.61	12.78
CASH FLOW								
Gas and Liquid Revenue	166.59	166.59	166.59	137.13	107.88	88.17	68.67	58.92
LESS								
Total Operating Costs	14.80	14.55	14.80	14.55	14.80	14.55	14.80	14.55
RTT	59.68	55.38	60.72	49.03	37.23	29.45	21.55	11.59
Tax	35.92	37.70	35.52	28.68	21.78	17.23	12.61	12.78
Total Capital	2.60	13.60	0.00	0.00	0.00	0.00	0.00	15.40
Cash Flow	53.59	45.37	55.56	44.86	34.07	26.94	19.72	4.60
Cum Cash Flow	757.13	802.50	858.05	902.92	936.99	963.93	983.65	988.24

IRR %	10.00	15.00	20.00
NPV $(Millions)	133.28	39.41	-0.02
IRR (CALC) %	20.00		

APPENDIX E

DRAWINGS

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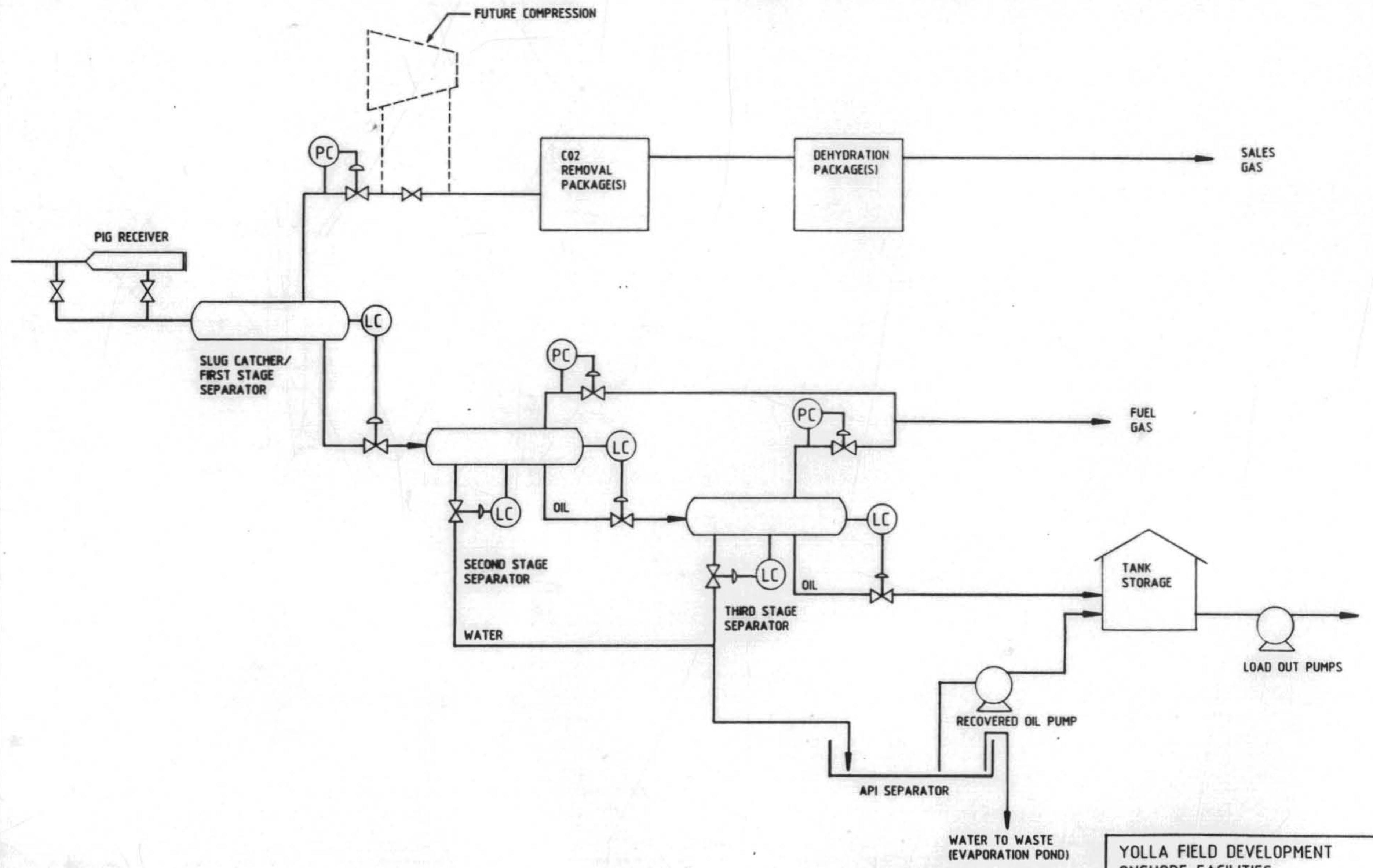


YOLLA FIELD DEVELOPMENT
ONSHORE FACILITIES

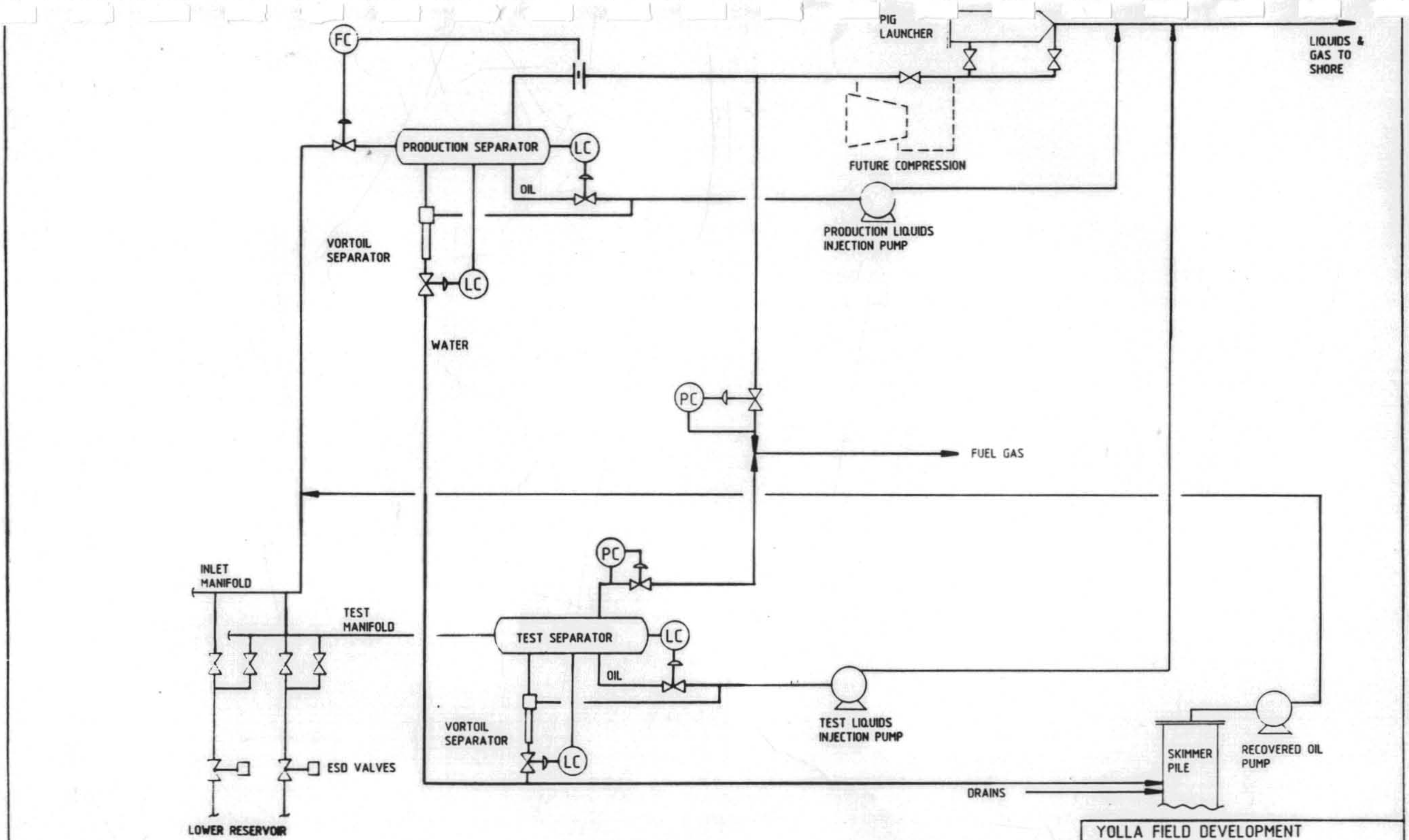
ALL CASES

N°	DATE	REVISION	BY	CHK'D	ENG	ENG MNGR	PROJ MNGR	APP'D

R.J. BROWN - CMPS
OFFSHORE ENGINEERS
12th Floor, Chatswood Plaza, South Tower,
Railway Street, Chatswood, N.S.W. 2067
P.O. Box 369, Chatswood, N.S.W. 2067
Tel: (02) 411 6751 Telex: AA171288
Fax: (02) 412 9505

Drawn LC	Date 4/3/89	Checked MF	Approved GG
Job No. 3002	Drawing No. 3002-001		Revision A

5 cm



Nº	DATE	REVISION	BY	CHK'D	ENG	ENG MNGR	PROJ MNGR	APP'D

NOTE: FUTURE DEVELOPMENT WELLS NOT SHOWN

R.J. BROWN - CMPS
OFFSHORE ENGINEERS
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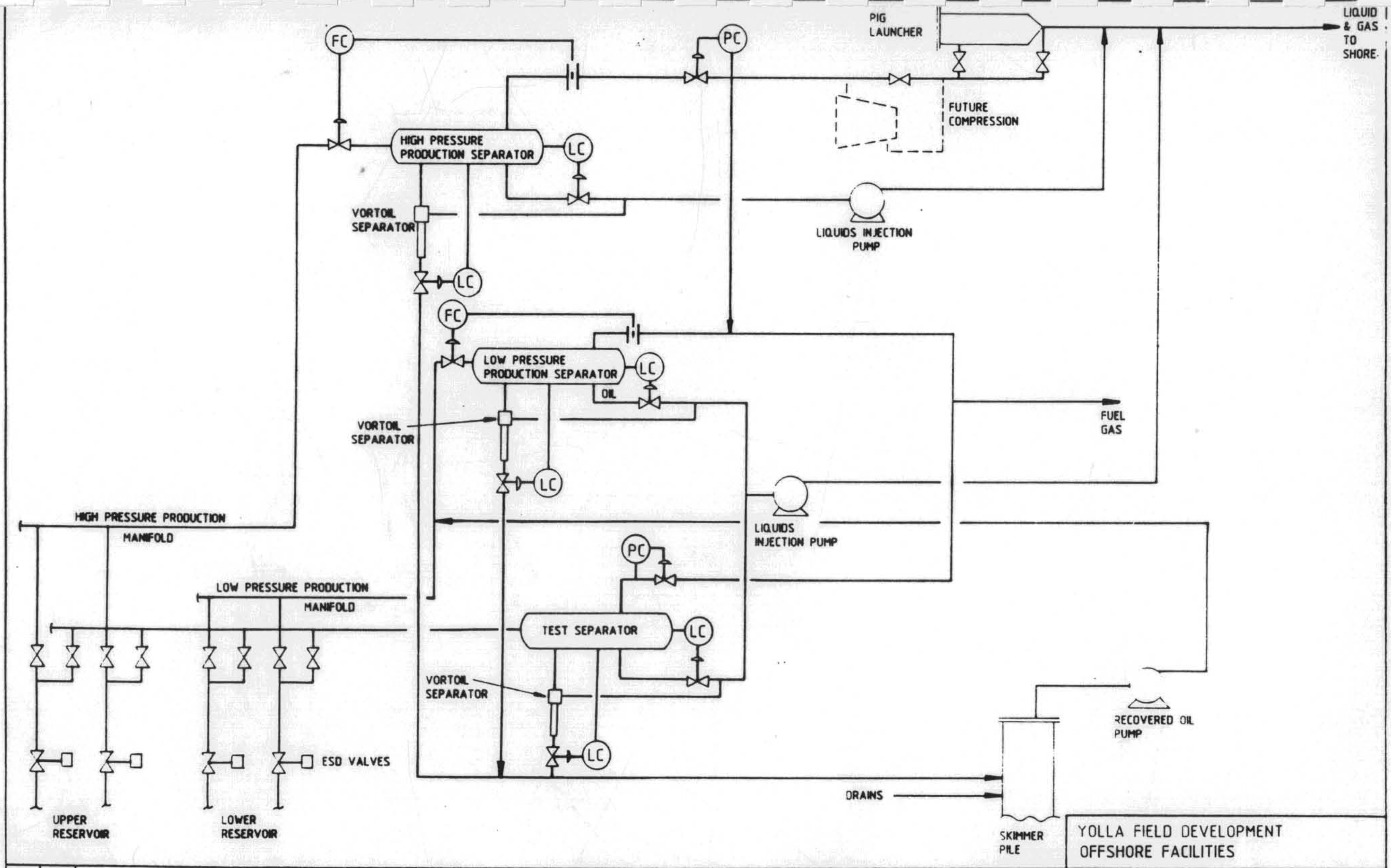
YOLLA FIELD DEVELOPMENT
OFFSHORE FACILITIES

CASE 1

Drawn	Date	Checked	Approved
LC	4/3/89	HF	GS
Job No. 3002	Drawing No. 3002-002		Revision A

5 cm



YOLLA FIELD DEVELOPMENT
OFFSHORE FACILITIES

CASES 2 & 4

NOTE: FUTURE DEVELOPMENT WELLS NOT SHOWN

Nº	DATE	REVISION	BY	CHK'D	ENG	ENG MNGR	PROJ MNGR	APP'D

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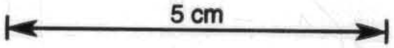
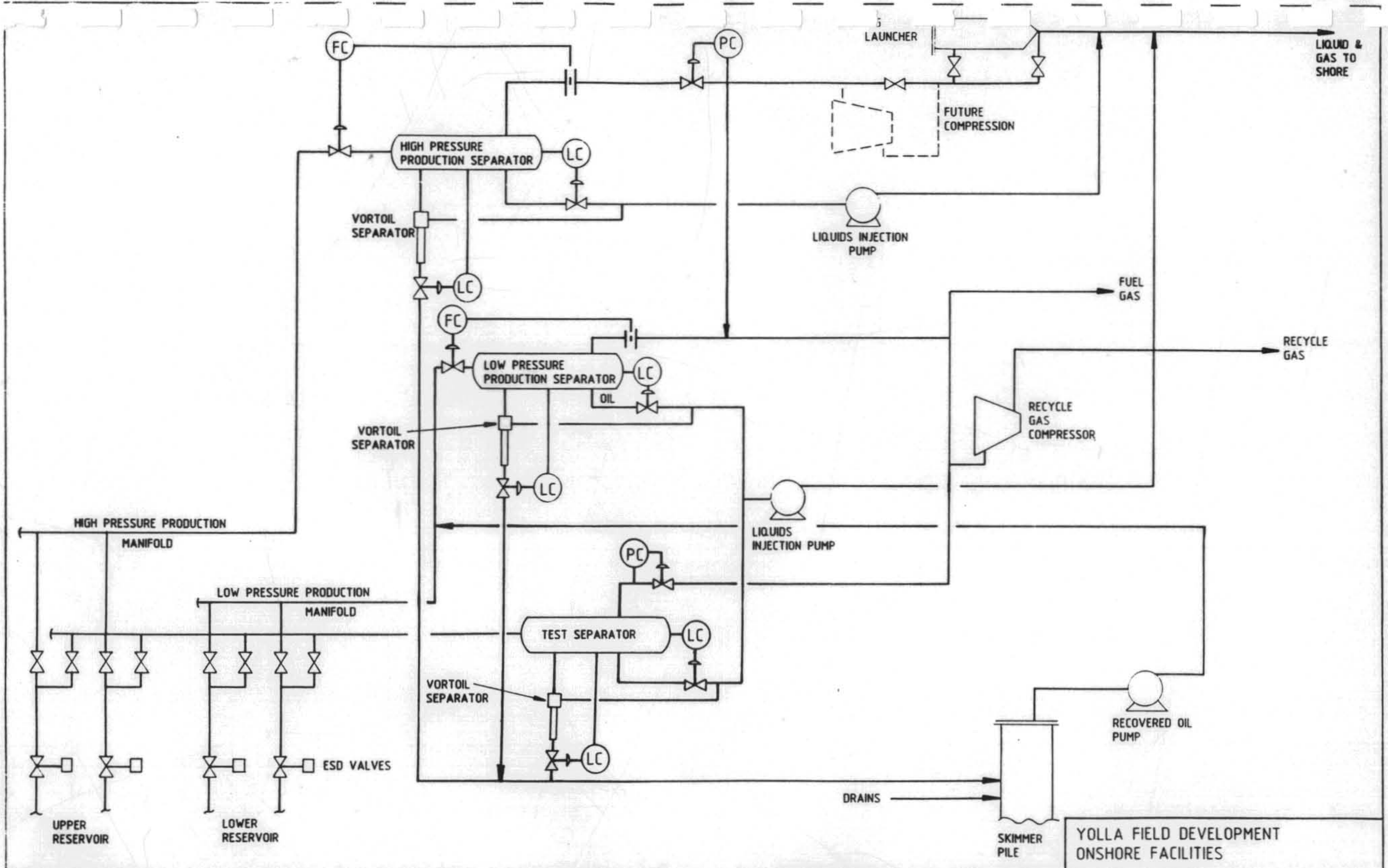
Drawn LC	Date 4/3/89	Checked MF	Approved GG
Job No. 3002	Drawing No. 3002-003		Revision A



A3 Sheet



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YOLLA FIELD DEVELOPMENT
ONSHORE FACILITIES

CASE 3

Nº	DATE	REVISION	BY	CHK'D	ENG	ENG MNGR	PROJ MNGR	APP'D

NOTE: FUTURE DEVELOPMENT AND RECYCLE WELLS NOT SHOWN

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Drawn LC	Date 4/3/89	Checked MF	Approved GG
Job No. 3002	Drawing No. 3002-004		Revision A

5 cm

APPENDIX F

DESIGN PARAMETERS

YOLLA GASFIELD DEVELOPMENT STUDY

1. Introduction

The Yolla Field is located within the Bass Basin, under the waters of Bass Strait between Tasmania and Victoria. Hydrocarbons occur at two levels, at the top of the Eastern View Coal Measures (ECVM) and at a deeper level within the same formation. (See Figures 1 and 2) Two successful drill stem tests (DST's) were conducted on Yolla and the tests demonstrated excellent reservoir parameters at the well.

DST 1 was run over the interval 2809 to 2814 metres and 2818 to 2825 metres in the deeper pay zone. This test established a stablised flowrate of 0.43 million cubic metres per day (15.2 MMCFD) of gas and 92.2 kilolitres (580 barrels) of 51.2 degree API gravity condensates through a $^{40}/_{64}$ inch choke.

DST 2 was run in two parts over the interval of 1813 to 1834 metres at the top of the Eastern View Coal Measures (EVCM). In the first stage of the test in which only the bottom 0.7 metres of the interval was perforated, 44.5° API oil was recovered at a rate of 47.7 kilolitres (300 barrels) per day accompanied by gas at 0.028 million cubic metres per day (1.0 MMCFD). The second stage of the test in which the whole interval was tested flowed gas at 0.334 million cubic metres per day (11.8 MMCFD) and condensate at 141.8 kilolitres (892 bbls) per day through a $^{80}/_{64}$ inch choke. DST 2 thus established a minor oil leg beneath a gas/condensate cap in the top of the EVCM.

Proven recoverable reserves have been estimated at between 300 to 400 BCF of gas and 10 to 14 million barrels of condensate in the deeper reservoir and 30 BCF of gas and 3.0 million barrels of condensate/oil in the top pay zone.

2. Project Brief

2.1 The study is to investigate and identify various development options and based on the development option selected develop preliminary economics with the aim of determining the landed price of Yolla gas in Victoria and Tasmania. It can be assumed that the Victorian and Tasmanian markets are mutually exclusive of one another. It is expected that the gas earmarked for the market will come mainly from the deeper pay zone at Yolla.

2.1 The study will also investigate the possibility of dual production from the top reservoir. The aim is to determine the feasibility of recovering oil and condensate and associated gas from the upper zone and its effect on the overall economics and landed price of gas in Tasmania and Victoria.

2.3 Considering that some additional wells are probably required to be drilled in the later part of the life of the field to augment deliverability, the study should also address the feasibility and economics of phasing in these wells earlier for use as dry gas recycling within the deeper pay zone.

2.4 The study should investigate the sensitivity on the landed price of gas using reserve of 190 BCF of gas and 9 million barrels of condensate in the lower zone and 10 BCF and 11 million barrels of oil in the upper zone. For this sensitivity study, the same deliverability and well requirements used in the base cases can be assumed. However, life of the field will have to be shortened to correspond with the total reserves recoverable.

2.5 The design philosophy should be to utilise only accepted and proven offshore development techniques with a minimum of processing facilities to be located offshore. Special efforts should be taken to minimise cost while providing adequate reliability and compliance with all applicable codes and regulations.

3. Input Data

3.1 The Yolla Field is located approximately 92 km. offshore due south-southeast of Wilson's Promontory in Victoria. The closest landmark in Tasmania is Stanley which is 112 km. south-southeast of the field. Wilson's Promontory is an environmentally sensitive area. Any gas processing plant for the Victorian side, would have to be situated north of the Promontory National Park.

3.2 Water depth is approximately 80m. over the entire field.

3.3 Two main pay zones are present in the Yolla Field. The shallower reservoir is at a depth of 1820 metres subsea. The deeper reservoir is present at a depth of 2805 metres subsea.

3.4 The average annual demand profile in the Tasmanian and Victorian markets are given in Appendix 1 and 2 respectively.

3.5 The wells operation shall be at a 60% annual load factor (ie. average day to peak day ratio).

3.6 Based on test data from Yolla - 1, gas flowrates of 35 and 40 MMCFD per well are achievable at bottomhole flowing pressures of 3860 and 3800 psia respectively for the deeper reservoir.

3.7 For the Tasmanian market, given the demand (Appendix 1) and load factor requirements, it is envisaged that initially two wells (total maximum deliverability of 80 MMCFD, average daily production, 48 MMCFD) will be sufficient to meet the projected demand. However, it is likely that from Year 11 onwards, one additional well will have to be drilled and from Year 15 a further one more well will be required to augment deliverability.

3.8 For the Victorian market, it is envisaged that four wells will be required initially. The maximum delivery capacity of the four wells will be 140 MMCFD at a 60% annual load factor, resulting in an average daily rate of 84 MMCFD. In year seven, it is envisaged that two more wells will have to be drilled to meet the projected gas demand.

3.9 Initial reservoir pressure and temperature at the deeper pay zone is 4203 psia and 276°F respectively.

3.10 For the shallow reservoir, an initial flowrate of 8 MMCFD of gas and 600 barrels of oil/condensate per day at a reservoir face flowing pressure of 1760 psi is achievable. However, we do not expect this rate to be sustained. It can be assumed that in a two well field, this rate will be sustained for a period of one year and for a four well field, the period will be six months. It can further be assumed that the deliverability in the wells for the upper reservoir will decline gradually.

3.11 Initial reservoir pressure and temperature at the shallow pay zone is 2713 psia and 207°F respectively.

3.12 A copy of the analyses for the gas and condensate from the two pay zones is attached as Appendices 3 and 4. Retrograde condensation of hydrocarbons in the reservoir is expected to occur. Included in Appendix 3 are hydrocarbon analyses of the produced well stream at different pressures for the deeper pay zone.

3.13 We expect the gas in the deeper reservoir will be subjected to isothermal volumetric depletion. For the top pay zone, hydrocarbon recovery will probably be subjected to some bottom water drive after an initial gas cap expansion.

3.14 The sales gas specification for both the Victorian and Tasmanian markets are as follows:

Delivery pressure	1000 psig
Maximum Hydrocarbon Dew Point @ 1000 psia	36°F
Maximum Oxygen content by volume	0.2%
Maximum Total Sulphur/100 cubic feet	2 grains
Maximum H_2S/100 cubic feet	0.25 grains
Maximum Mercaptan/100 cubic feet	0.20 grains
Total Calorific value/cubic feet - maximum	1100 Btu
- minimum	980 Btu
Wobbe Index - maximum	1365
- minimum	1235

3.15 Determination of the landed gas price required to make the development project break even at discount rates of 10, 15 and 20% should be studied in the economic section. Analysis should be carried out in both real terms (ie. no escalation factor) and in money of the day terms.

3.16 It is assumed that one workover will be required every two years. The estimated cost of these workovers is A$250,000 for a platform well and $700,000 for a subsea completed well.

3.17 Commonwealth RRT regime will apply.

3.18 The gas delivery point for the study should be at the outlet of the onshore gas treatment plant.

3.19 It is estimated that production wells will cost A$10 million each to drill and complete, assuming a 30 day total programme.

3.20 A nominal overhead should be charged to the project to cover operator office engineering support.

3.21 The discovery well Yolla - 1 was suspended in October 1985, and it is possible to re enter well.

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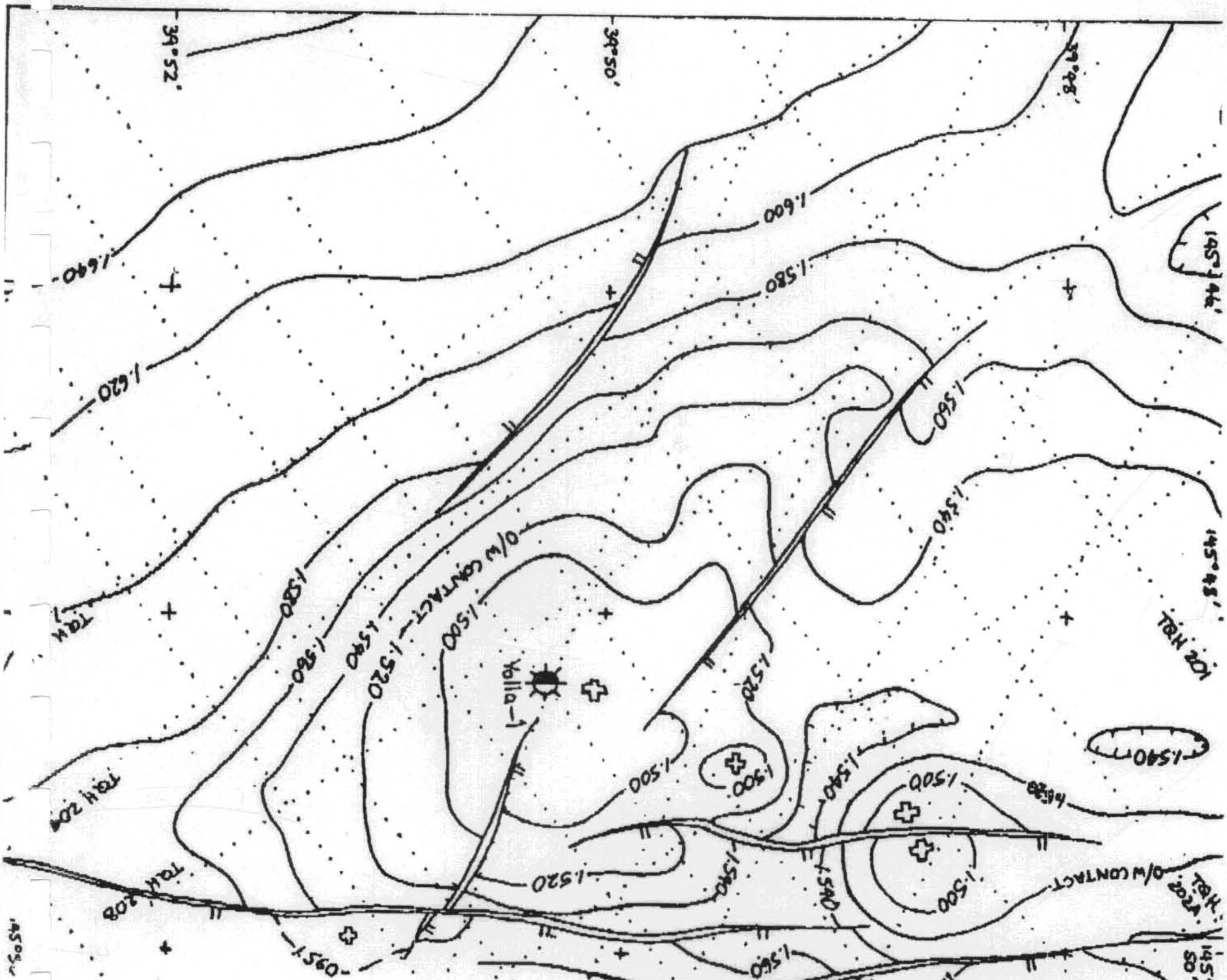

FIGURE 1 : YOLLA TIME STRUCTURE - TOP EASTERN VIEW COAL MEASURES
(After Newman, E. & Magee, M, August 1987).

5 cm

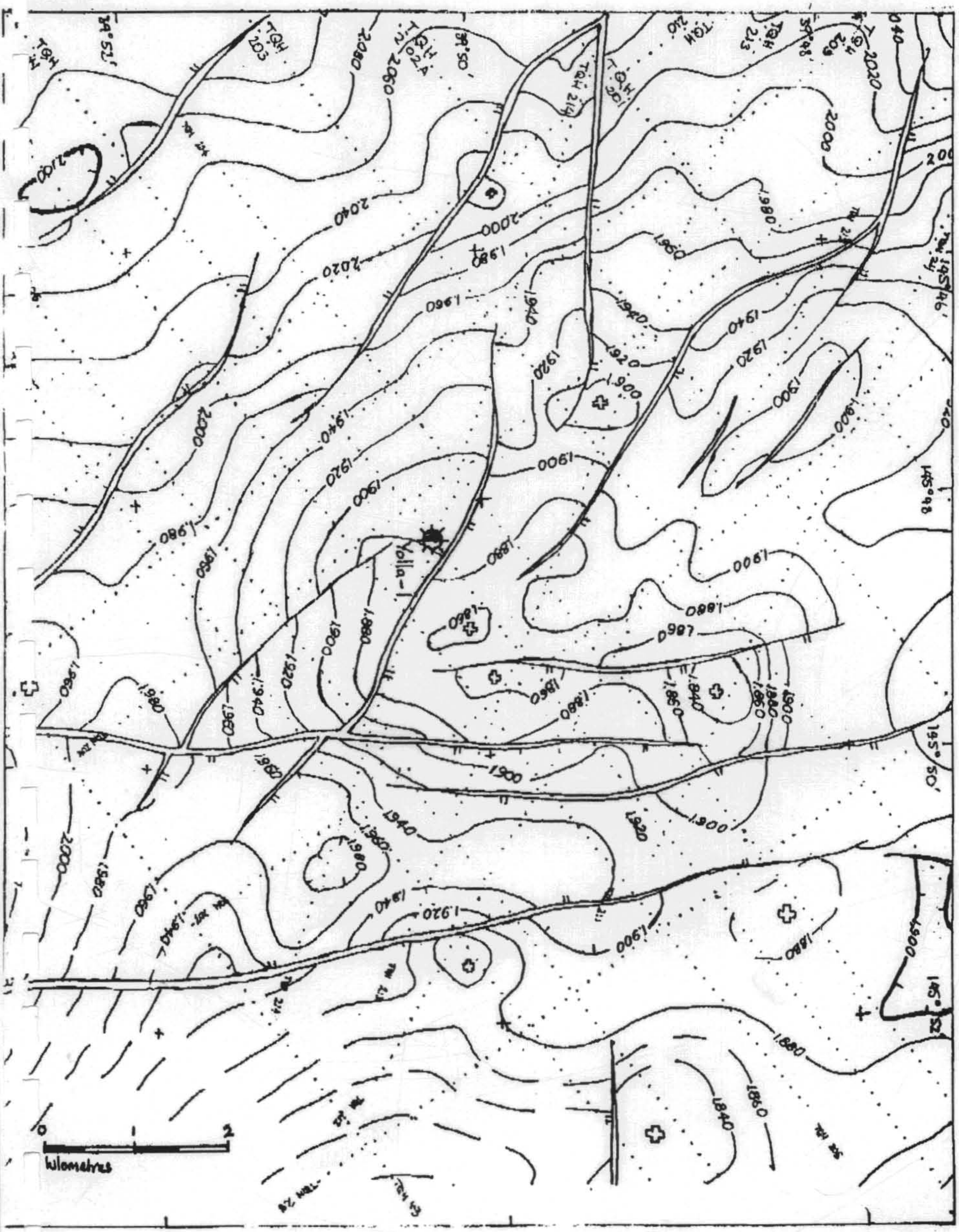

FIGURE 2 : YOLLA TIME STRUCTURE - LOWER M. DIVERSUS
(After Newman, E. & Magee, M, August 1987).

5 cm

APPENDIX 1.

POSSIBLE TASMANIAN MARKET PROFILE

YEAR FROM COMMISSIONING	GAS DEMAND (PJ)
1	12
2	14
3	15
4	15
5	16
6	16
7	17
8	17
9	17
10	17
11	17
12	17
13	17
14	17
15	17
16	17
17	14
18	11
19	9
20	7
21	6

APPENDIX 2.

POSSIBLE VICTORIAN MARKET PROFILE

YEAR FROM COMMISSIONING	GAS DEMAND (PJ)
1	30
2	30
3	30
4	30
5	30
6	30
7	30
8	30
9	24
10	18
11	12
12	9
13	6

APPENDIX 3.

HYDROCARBON ANALYSES OF SEPARATOR PRODUCTS AND CALCULATED WELL STREAM TO UNDECANES PLUS

Cylinder #:	A11039	A5490	
Component	Separator Liquid Mol Percent	Separator Gas Mol Percent	Well Stream Mol Percent
Hydrogen Sulphide	0.00	0.00	0.00
Carbon Dioxide	7.85	19.48	18.86
Nitrogen	0.03	0.21	0.20
Methane	13.96	66.70	63.87
Ethane	6.43	7.71	7.64
Propane	7.69	3.53	3.75
iso-Butane	2.52	0.54	0.65
n-Butane	5.09	0.81	1.04
iso-Pentane	2.96	0.23	0.38
n-Pentane	3.42	0.22	0.39
Hexanes	6.93	0.18	0.54
Heptanes	10.81	0.17	0.74
Octanes	7.82	0.14	0.55
Nonanes	5.50	0.05	0.34
Decanes	3.67	0.01	0.21
Undecanes plus	15.32	0.02	0.84
	100.00	100.00	100.00

Properties of Heptanes plus			
API gravity @ 60°F	45.6		
Density, gm/cc @ 60°F	0.7984		0.793
Molecular weight	142	103 (assumed)	137

Calculated separator gas gravity (air = 1.000) = 0.858
Calculated gross heating value for separator gas
per cubic foot of dry gas @ 14.696 psia and 60°F = 991 BTU

Primary separator gas collected @ 740 psig and 105°F
Primary separator liquid collected @ 740 psig and 105°F

Primary separator gas/separator liquid ratio : 19233 SCF/Bbl @ 105°F
Primary separator liquid/stock tank liquid ratio : 1.331 Bbls @ 105°F/Bbl
Primary separator gas/well stream ratio : 946.58 MSCF/MMSCF
Stock tank liquid/well stream ratio : 37.0 Bbls/MMSCF

DEPLETION STUDY @ 292°F

Hydrocarbon Analyses of Produced Well Stream - Mol Percent

	3688 ?	Reservoir Pressure - psig						
Component	2683	3200	2700	2100	1500	1000	500	500*
Hydrogen Sulphide	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Carbon Dioxide	18.86	18.89	18.91	18.91	18.93	18.97	19.00	3.38
Nitrogen	0.20	0.21	0.22	0.22	0.21	0.21	0.20	0.21
Methane	63.87	64.18	64.40	64.57	64.56	64.33	63.42	7.72
Ethane	7.64	7.63	7.63	7.64	7.66	7.68	7.74	2.01
Propane	3.75	3.73	3.72	3.73	3.75	3.78	3.84	2.08
iso-Butane	0.65	0.61	0.59	0.59	0.61	0.67	0.76	0.62
n-Butane	1.04	1.00	0.99	0.99	0.99	1.04	1.12	1.21
iso-Pentane	0.38	0.36	0.35	0.34	0.36	0.39	0.44	0.70
n-Pentane	0.39	0.37	0.36	0.36	0.38	0.41	0.46	0.85
Hexanes	0.54	0.53	0.51	0.50	0.51	0.52	0.60	1.88
Heptanes	0.74	0.72	0.71	0.71	0.70	0.71	0.75	3.94
Octanes	0.55	0.53	0.51	0.49	0.49	0.49	0.63	5.31
Nonanes	0.34	0.32	0.30	0.29	0.28	0.28	0.36	4.74
Decanes	0.21	0.19	0.18	0.16	0.15	0.15	0.25	4.35
Undecanes plus	0.84	0.73	0.62	0.50	0.42	0.37	0.43	61.00
	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molecular weight of heptanes plus	137	133	129	124	121	120	123	199
Density of heptanes plus	0.793	0.788	0.784	0.779	0.777	0.776	0.778	0.840
Deviation Factor-Z								
Equilibrium gas	0.907	0.898	0.896	0.906	0.923	0.945	0.972	
Two-phase	0.907	0.891	0.886	0.889	0.904	0.921	0.947	
Gas viscosity	0.0269	0.0240	0.0214	0.0188	0.0167	0.0153	0.0142	
Well Stream produced - Cumulative percent of initial	0	11.522	24.781	41.636	58.871	72.953	86.653	

* Composition of equilibrium liquid phase

CALCULATED CUMULATIVE RECOVERY DURING DEPLETION

472341

Cumulative Recovery per MMSCF of Original Fluid ([illegible])	Initial in Place	Reservoir Pressure - psig						
		3683	3200	2700	2100	1500	1000	500
Well Stream - MSCF	1000	0	115.22	247.81	416.36	588.71	729.53	866.53
Normal Temperature Separation *								
Stock Tank Liquid - Barrels	41.43	0	4.33	8.86	14.05	19.05	23.09	27.93
Primary Separator Gas - MSCF	941.65	0	109.02	235.00	395.73	560.05	694.85	824.14
Second Stage Gas - MSCF	19.11	0	2.02	4.18	6.74	9.28	11.39	13.97
Stock Tank Gas - MSCF	3.68	0	0.39	0.80	1.29	1.79	2.22	2.75
Total "Plant Products" in Primary Separator Gas - Gallons								
Ethane	1939	0	224	483	813	1152	1430	1699
Propane	905	0	105	226	382	542	674	801
Butanes (total)	399	0	42	97	163	233	294	356
Pentanes plus	274	0	32	69	116	167	212	254
Total "Plant Products" in Second Stage Gas - Gallons								
Ethane	78	0	8	17	28	38	47	57
Propane	66	0	7	14	23	32	40	49
Butanes (total)	37	0	4	8	13	18	22	27
Pentanes plus	24	0	3	5	8	12	15	19
Total "Plant Products" in Well Stream - Gallons								
Ethane	2038	0	234	504	848	1200	1488	1771
Propane	1029	0	118	253	426	603	749	894
Butanes (total)	539	0	59	126	211	299	376	458
Pentanes plus	1963	0	208	430	690	945	1153	1397

* Primary separator @ 740 psig and 105°F, second stage @ 50 psig and 90°F, stock tank @ 90°F.

472342

APPENDIX 4.

CORE LABORATORIES
Petroleum Reservoir Engineering

Page : 1 of 8
File : AFL 85062

Company : Amoco Australia Petroleum Co.
Date Sampled : 4th October, 1985
Well : Yolla #1, DST #3
State : Tasmania
Field : Wildcat
Country : Australia

FORMATION CHARACTERISTICS

Formation Name :
* Original Reservoir Pressure : 2695 psig @ 6012 ft
Original Produced Gas-Oil Ratio :
Production Ratio :
Separator Pressure and Temperature :
Liquid Gravity @ 60°F :
Datum :

WELL CHARACTERISTICS

Elevation : 35.75 ft RKB
Total Depth :
Producing Interval : 5947 - 6015 ft RKB
Tubing Size : 4½ inch drill pipe
Open Flow Potential :
Last Reservoir Pressure : Original Test
Date :
** Reservoir Temperature : 209°F @ 6012 ft RKB
Status of Well :
Pressure Gauge :

SAMPLING CONDITIONS

Flowing Tubing Pressure : 950 psig
Flowing Bottom Hole Pressure :
Primary Separator Pressure : 625 psig
Primary Separator Temperature : 112°F
Secondary Separator Pressure :
Secondary Separator Temperature :
Field Stock Tank Liquid Gravity : 50.6°API @ 60°F
Primary Separator Gas Production Rate : 11800 MSCF/Day
Pressure Base : 14.73 psia
Temperature Base : 60°F
Compressibility Factor (Fpv) : 1.0670
Gas Gravity (Field) : 0.790
Gas Gravity Factor (Fg) : 1.12509
Separator Liquid Production Rate @ 112°F : 897 Bbls/Day
Primary Separator Gas/Separator Liquid Ratio : 13229 SCF/Bbl @ 625 psig & 112°F
or : 75.59 Bbl/MMSCF

Sampled by : Otis Engineering
REMARKS :

* Original reservoir pressure based on RFT point @ 6012 ft.
** Corrected from RPC gauge @ 5807 ft to 6012 ft using 2.5°/100 ft.

Page : 3 of 8
File : AFL 85062
Well : Yolla #1, DST #3

HYDROCARBON ANALYSIS OF SEPARATOR GAS SAMPLE TO TRIDECANES PLUS

Cylinder #:		A8626	
Component	Mol Percent		GPM
Helium	0.00		
Hydrogen Sulphide	0.00		
Carbon Dioxide	7.49		
Nitrogen	0.49		
Methane	74.66		
Ethane	8.98		2.395
Propane	5.11		1.402
iso-Butane	0.89		0.290
n-Butane	1.16		0.365
iso-Pentane	0.34		0.124
n-Pentane	0.28		0.101
Hexanes	0.21		0.081
Heptanes	0.19		0.177 (C7+)
Octanes	0.11		
Nonanes	0.05		
Decanes	0.02		
Undecanes	0.01		
Dodecanes	0.01		
Tridecanes plus	trace		
	100.00		4.935

Gas gravity (Air = 1.000): 0.780

Gross heating value (BTU per cubic foot of dry gas @ 14.696 psia and 60°F): 1165

472344

CORE LABORATORIES
Petroleum Reservoir Engineering

Page : 4 of 8
File : AFL 85062
Well : Yolla #1, DST #3

HYDROCARBON ANALYSIS OF SEPARATOR LIQUID SAMPLE TO EICOSANES PLUS

Cylinder #: OT069T

Component	Mol Percent	Weight Percent
Hydrogen Sulphide	0.00	0.00
Carbon Dioxide	2.59	1.13
Nitrogen	0.26	0.07
Methane	13.32	2.11
Ethane	6.56	1.95
Propane	9.10	3.96
iso-Butane	3.32	1.91
n-Butane	5.84	3.35
iso-Pentane	3.35	2.39
n-Pentane	3.48	2.48
Hexanes	5.75	4.94
Heptanes	10.86	10.30
Octanes	7.09	7.42
Nonanes	4.87	5.63
Decanes	3.77	4.92
Undecanes	2.21	3.25
Dodecanes	2.22	3.55
Tridecanes	1.97	3.46
Tetradecanes	1.58	3.03
Pentadecanes	1.43	2.91
Hexadecanes	1.52	3.33
Heptadecanes	1.48	3.49
Octadecanes	1.10	2.76
Nonadecanes	0.95	2.52
Eicosanes plus	5.38	19.14
	100.00	100.00

Page : 6 of 8
File : AFL 85062
Well : Yolla #1, DST #3

BASIC CRUDE TESTS ON STOCK TANK OIL

Sample:	OT069T
Pour Point:	59°F
Wax Content:	7.721%
Kinematic Viscosity: (centistokes)	No movement @ 60°F
	2.091 @ 80°F
	1.690 @ 100°F
	1.245 @ 150°F
	0.830 @ 212°F
Water and Sediment (BS&W):	0.975%

APPENDIX 3

TPR
OR-363
Vol IV/A

4723.46

NATURAL GAS FOR TASMANIA

An Analysis Of The Market Potential For Natural Gas

SAGASCO RESOURCES LIMITED

October 1989

TPR
OR-363
VOL IV/A

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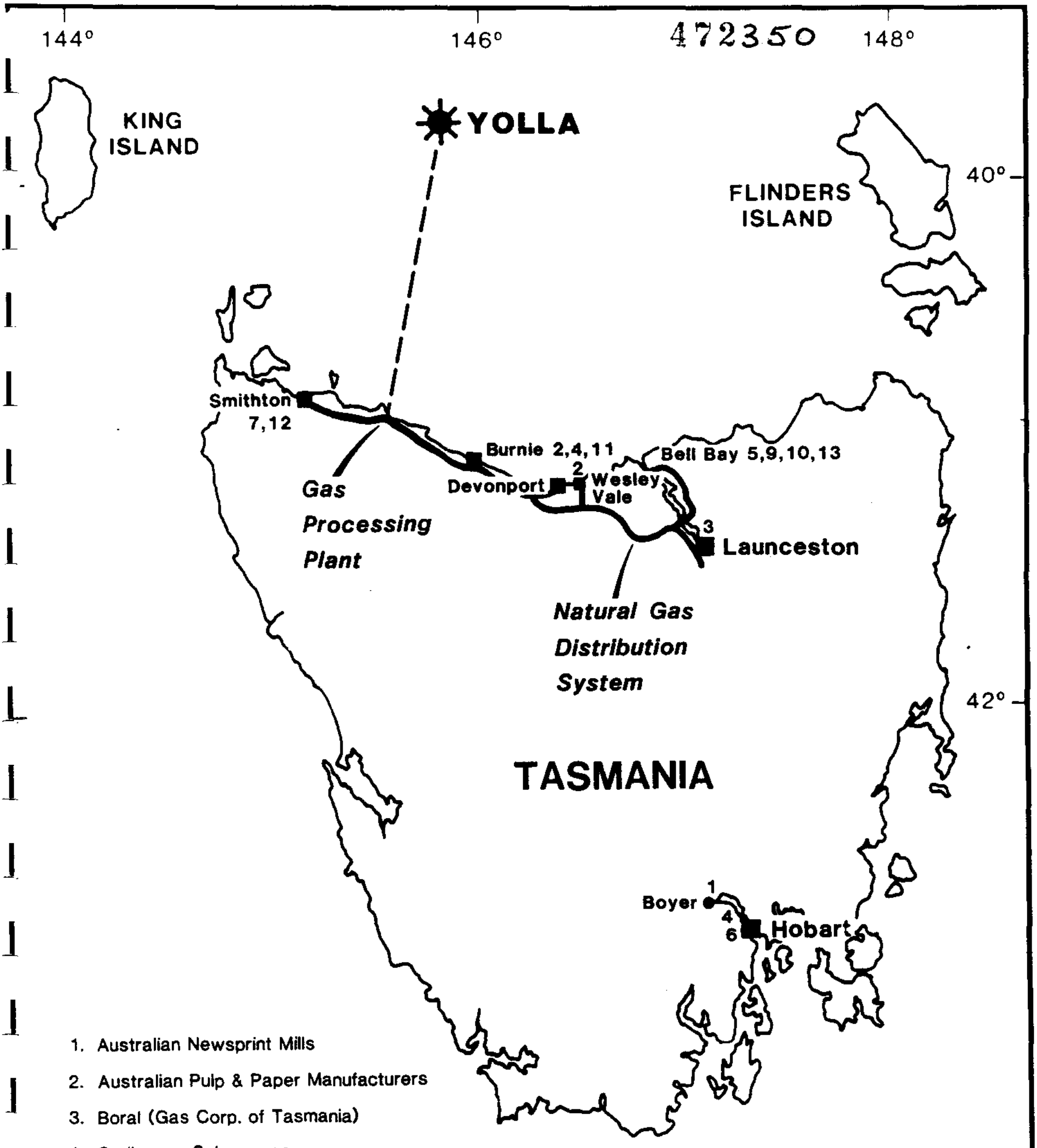
EXECUTIVE SUMMARY

Tasmania remains the only state or territory in Australia which does not have access to natural gas supplies. The development of gas reserves which were discovered in Permit T14/P with the drilling of Yolla 1 has the potential to remedy this situation but the market for natural gas in Tasmania must be large enough to justify the required commitment of capital to the project.

Preliminary economic analysis which has been done as an integral part of the R J Brown - CMPS Yolla Development Study has shown that the project could be viable with a demand for gas in the order of 17 PJ per year. At this volume gas could be supplied at the outlet of a processing plant at a price ranging from $2.90 to $4.60 per GJ (1989$).

A review of the potential markets for natural gas in Tasmania indicates that, at prices indicated by the engineering study, natural gas could successfully compete for a market share of between 15 and 20 PJ per year. Figure 1 shows the location of the Yolla discovery relative to the proposed market for natural gas. Figure 2 represents a base forecast of gas demand which could realistically be expected to develop should the gas resource at Yolla be made available to the market. That demand is made up of the use of natural gas for the generation of electricity by the Hydro Electric Commission of Tasmania under assumptions of gradual load growth within their system and the substitution of natural gas for other thermal fuels used by industrial, commercial and domestic consumers where appropriate.

Figure 3 shows how the demand for natural gas would be affected if gas turbines installed by the Hydro Commission were to be operated from startup in such a way as to use a minimum of 80% of the gas demand for long term base load power generation. The profile shown in this graph is very similar to the gas market forecast used as a basis for the RJ Brown - CMPS Yolla Development Study.



1. Australian Newsprint Mills
2. Australian Pulp & Paper Manufacturers
3. Boral (Gas Corp. of Tasmania)
4. Cadbury – Schweppes
5. Comalco
6. Electrolytic Zinc
7. McCain Foods
8. Savage River Mines
9. Southern Aluminium
10. TEMCO
11. Tioxide Australia
12. United Milk Tasmania
13. HECT Bell Bay Power Station

TASMANIA -

LOCATION OF MAJOR INDUSTRIES

Figure 1

NATURAL GAS FOR TASMANIA

Gas Market Development
With No New Industries

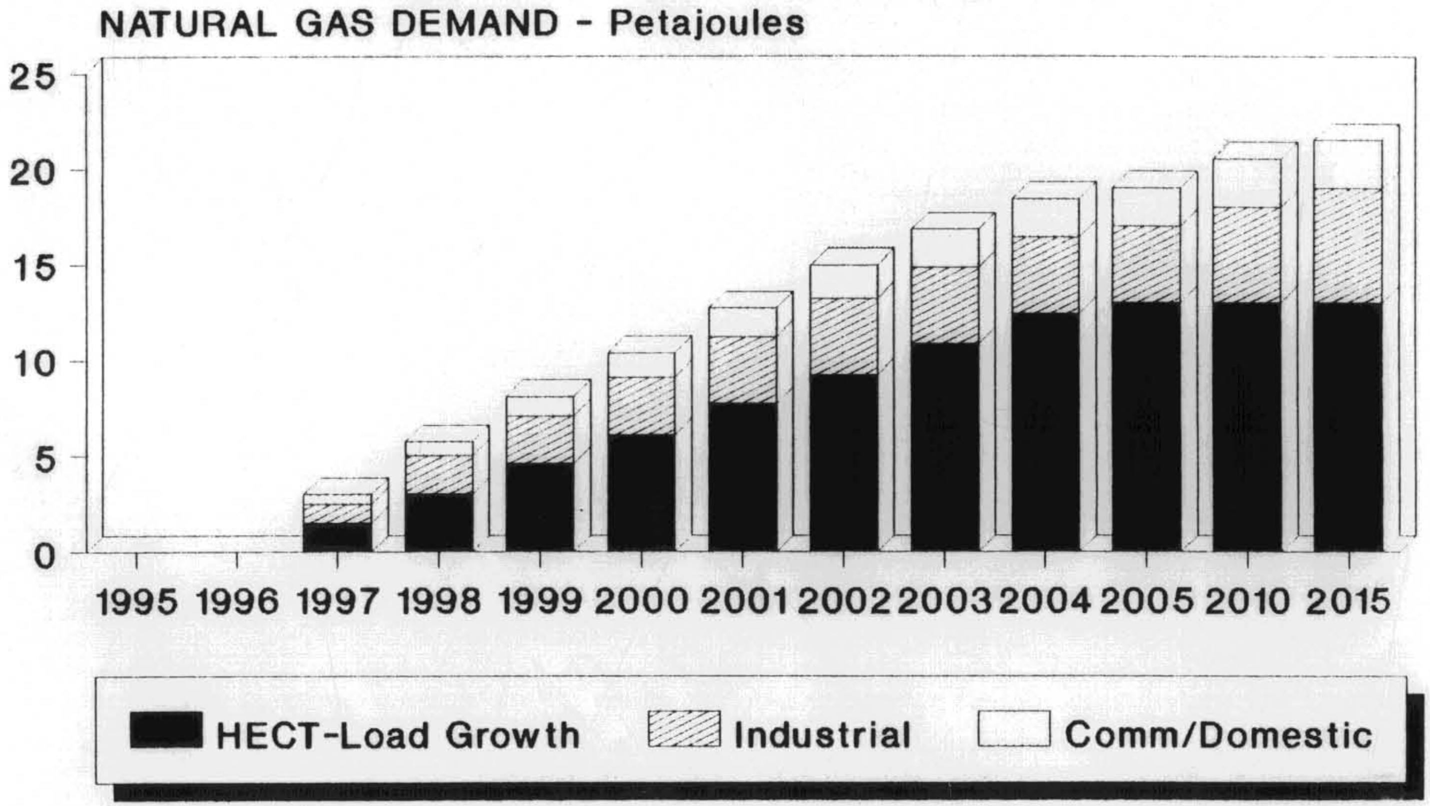


Figure 2

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NATURAL GAS FOR TASMANIA

Gas Market Development

With HECT Demand At Minimum Of 80%

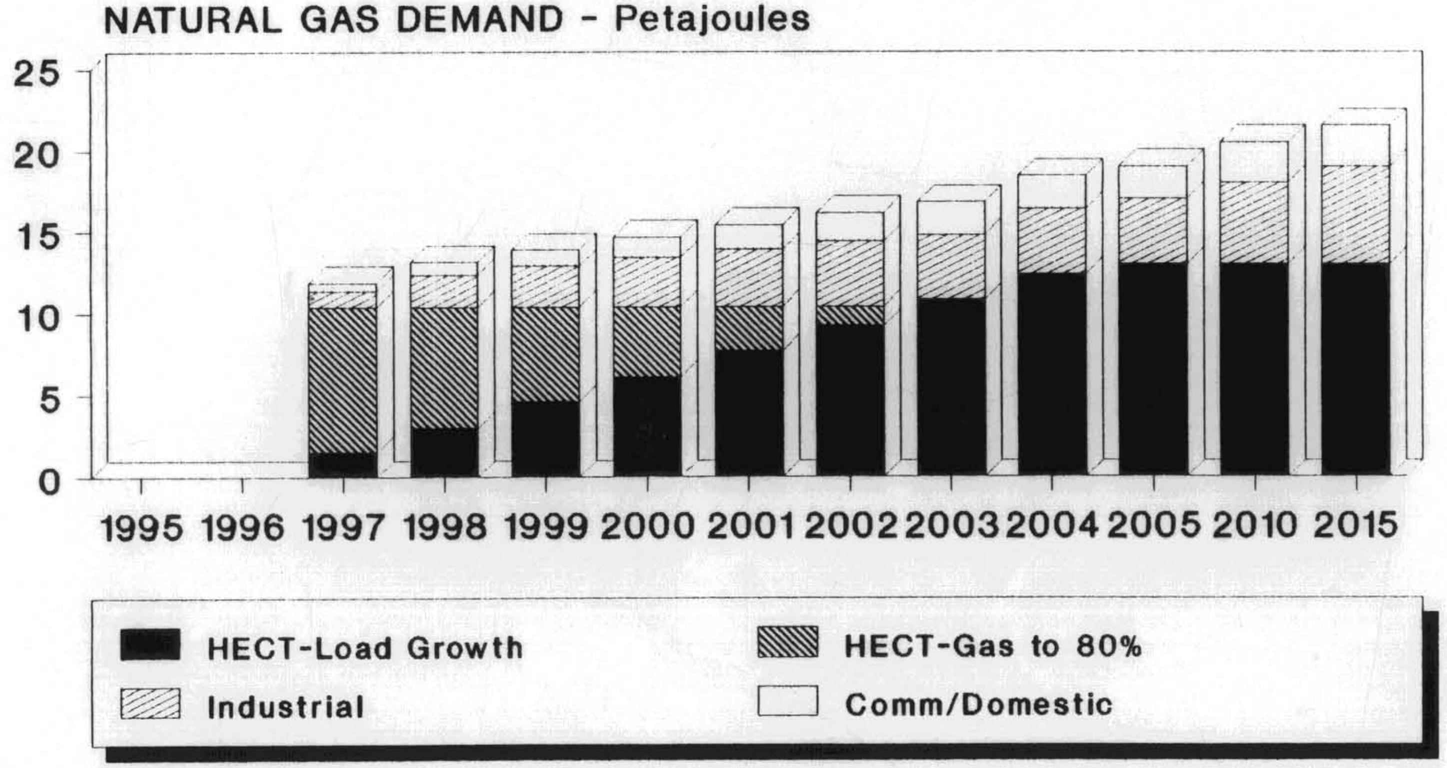

Figure 3

5 cm

NATURAL GAS MARKET DEVELOPMENT WITHOUT NEW TASMANIAN INDUSTRIES

	Electricity Demand Growth	Industrial Users	Commercial /Domestic Users	Total
	------------------ PJ per year ------------------			
1995	0	0	0	0
1996	0	0	0	0
1997	1.5	1.0	0.5	3.0
1998	3.0	2.0	0.7	5.7
1999	4.6	2.5	1.0	8.1
2000	6.1	3.0	1.2	10.3
2001	7.7	3.5	1.5	12.7
2002	9.2	4.0	1.7	14.9
2003	10.8	4.0	2.0	16.8
2004	12.4	4.0	2.0	18.4
2005	13.0	4.0	2.0	19.0
2010	13.0	5.0	2.5	20.5
2015	13.0	6.0	2.5	21.5

NATURAL GAS MARKET DEVELOPMENT WITH HECT DEMAND AT MINIMUM OF 80%

	Total With Normal Electricity Demand Growth	Additional HECT Demand to 80%	Total
	------------------ PJ per year ------------------		
1995	0	0	0
1996	0	0	0
1997	3.0	8.9	11.9
1998	5.7	7.4	13.1
1999	8.1	5.8	13.9
2000	10.3	4.3	14.6
2001	12.7	2.7	15.4
2002	14.9	1.2	16.1
2003	16.8	0	16.8
2004	18.4	0	18.4
2005	19.0	0	19.0
2010	20.5	0	20.5
2015	21.5	0	21.5

472354

The potential which exists for the establishment of major new industries in Tasmania could result in the acceleration of requirements for new power generating capacity. Such projects could require the commissioning of new facilities by 1995 with demand for 17 PJ per year of gas being realised before 2000.

Ultimate demand for natural gas in Tasmania could expand to more than 30 PJ per year. Technologies are available or are being developed which could be tailored for operation in Tasmania and which would use natural gas as a feedstock for the manufacture of petrochemicals and synthetic liquid transportation fuels.

472355

1. INTRODUCTION

A key to the development of natural gas and associated gas liquids in the Yolla field will be the establishment of a gas market which will provide a demand sufficient to meet an economic threshold production rate. Volumes of gas delivered to the market place will have to compete against alternative energy sources such as hydroelectricity, coal and fuel oil. In order to effectively compete on a cost basis, the gas volumes will have to be high enough to reduce the unit cost of delivered natural gas to a level which will make the conversions, necessary to allow for the use of natural gas, economically attractive to potential customers.

This report examines the market potential which exists in Tasmania for natural gas. That potential is made up of two principal components; the use of natural gas in the generation of electricity and the substitution of natural gas for other thermal fuels by industry. There is also potential for natural gas to replace alternative thermal fuels in portions of the commercial and domestic markets. Further appraisal drilling is required to prove up Yolla gas reserves. The timing of this drilling is going to depend on the expectation of a market large enough to ensure commercial viability of a Yolla resource development.

The use of natural gas in the generation of electricity has been analysed by P M Garlick & Associates Pty Ltd ('The Consultant'). A report prepared by the Consultant is summarised in this report and has been included as Appendix A to this report.

The potential for the industrial use of natural gas has been analysed through discussions held with major thermal fuel users in Tasmania. These discussions included a review of present fuel consumption, plans for future expansion and the ease with which natural gas could be substituted for the current fuel supply.

All prices quoted in this report are expressed in 1989 dollars unless otherwise noted.

2. INDUSTRIAL MARKETS FOR NATURAL GAS

2.1 Existing Markets

Much of Tasmania's industrial base is centred on the northern coastal area, as shown in Figure 1, around the cities of Launceston, Burnie and Devonport. This industrial base is built around Tasmania's key natural resource strengths:

- timber and timber products
- mineral processing
- agriculture

A large part of this industry is energy intensive, relying on hydroelectric power, fuel oil, coal and LPG for energy. Proximity to the northern coastline would make much of it readily accessible to a natural gas pipeline distribution network if the gas resources of the Yolla field were to be developed.

After the discovery of Yolla in 1985, discussions were held with a number of companies which have significant requirements for thermal fuels. The fuel consumption data for those companies has been updated and new data has been collected for several other companies which were not included in the 1985 study. Table 1 summarises the thermal fuel consumption for the largest industrial users in Tasmania.

The aggregate energy demand of the northern coastline industries is approximately 7 PJ per year. Of this, approximately 4 PJ could be converted with relative ease from coal, fuel oil and LPG to natural gas if it were available. Several of the companies contacted have already replaced, or have plans to replace, older boiler equipment with boilers which are suitable for LPG.

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TABLE 1

NATURAL GAS FOR TASMANIA

POTENTIAL INDUSTRIAL CUSTOMERS FOR NATURAL GAS

COMPANY	LOCATION	BUSINESS	THERMAL FUEL REQUIREMENTS						NOTES
			COAL	FUEL OIL	DIESEL	LPG	WOOD WASTE	TOTAL PJ/YR	
			--------------(tonnes / year)-----------------						
1. Australian Newsprint Mills	Boyer	Paper Production	100,000 60,000					2.3 1.4	Tasmanian coal price based on landed cost of NSW coal; high ash handling cost; 60 kt/yr associated with planned expansion
2. Australian Pulp & Paper Manufacturers	Burnie	Paper Production	70,000	3,500				1.8	
	Wesley Vale			20,000				0.9	
3. Boral (Gas Corp of Tasmania)	Launceston	LPG Distribution				20,000		1.0	Industrial customer volumes only; 3 largest customers use 14 kt/yr; LPG purchased from BHP's Long Island Point facilities
4. Cadbury-Schweppes	Claremont	Chocolate Manufacturing	5,000	500				0.14	May be replacing existing boilers with multi-fuel boilers within 5 years
	Burnie	Milk Processing		1,200				0.06	
5. Comalco	Bell Bay	Aluminium Production		12,000	19	170		0.5	
6. Electrolytic Zinc	Hobart	Zinc Smelting			4,500	2,200		0.3	
7. McCain Foods	Smithton	Frozen Vegetable Processing					50,000	0.8	Low purchase cost/high handling cost

CONFIDENTIAL

TABLE 1

NATURAL GAS FOR TASMANIA

POTENTIAL INDUSTRIAL CUSTOMERS FOR NATURAL GAS

COMPANY	LOCATION	BUSINESS	THERMAL FUEL REQUIREMENTS						NOTES
			COAL	FUEL OIL	DIESEL	LPG	WOOD WASTE	TOTAL PJ/YR	
			-------------(tonnes / year)------------------						
8. Savage River Mines	Port Latta	Ore Pelletising	12,500	12,600	130			0.8	Currently using 1.8PJ/yr but existing product sales contract expires in 1990, resulting in reduced output
9. Southern Aluminium	Bell Bay	Aluminium Alloy Wheel Manufacturing				1,800		0.1	
10. TEMCO	Bell Bay	Ferro-Alloy Product Manufacturing		400				0.02	1985 Data
11. Tioxide Australia	Heybridge	Pigment Manufacturing	26,000	5,000		10,000		1.3	Old boilders are currently being converted to LPG; Expanding by 25% but no change to fuel requirement forecast
12. United Milk Tasmania Ltd	Smithton	Milk Processing				3,300	10,000	0.3	Wood waste is free but costs $180 k/yr to handle
Total:- Tasmania			273,500	55,200	4,649	20,000	60,000	10.8	Excludes LPG except for Boral; Excludes internally produced wood waste for paper plants
- North Coast			108,500	54,700	149	20,000	60,000	6.9	
Total Petajoules/year									
- Tasmania			6.2	2.4	0.2	1.0	1.0	10.8	
- North Coast			2.5	2.4	0.0	1.0	1.0	6.9	

Of the companies contacted for this study, Australian Newsprint Mills was the only company which identified firm plans for expansion which would significantly increase thermal fuel requirements. Located in Boyer, near Hobart, ANM is not in close proximity to the preliminarily proposed natural gas distribution network. The high volumes of liquids which would be produced in association with the gas might, however, compete with the coal which is currently ANM's principal fuel. In the longer term, if sufficient load developed in the Hobart region, gas may be able to be economically supplied via a cross-state pipeline.

2.2 Potential New Markets

Based on discussions with the Tasmanian Development Authority, the most likely types of new industries which might be established in Tasmania would be based on metal processing. Potential industries include a magnesium processing plant, a specialised steel mill, a tin smelter and an additional aluminium foundry. These types of industries do not typically have large thermal fuel requirements; relying mainly on electricity. Such industries do, however, have the potential to add significant load to the Tasmanian power system and could advance the need for new electricity generating capacity. The role which natural gas might play in meeting this need is examined in Section 3.2 of this report.

The new pulp mill which was proposed for construction at Wesley Vale could have increased demand for gas by approximately 1 PJ per year. North Broken Hill, a partner in the proposed plant, has recently indicated that the project team has been disbanded and that there are no discussions under way which might result in the project being resurrected. However, other potential pulp mill or pulp and paper mill projects may be proposed in the future based on technologies which meet government environmental guidelines.

2.3 Prices of Alternative Fuels

Tasmania's need to import all liquid thermal fuels involves high transportation costs which, when combined with the fluctuating price of oil, means that Tasmanian industries suffer a competitive disadvantage relative to the Australian mainland industrial base. All other states and territories have access to competitively priced natural gas. Even indigenous sources of coal supply, which because of high ash yield are only suitable for limited uses, are priced based on the cost of comparable coal imported from New South Wales. While most companies stated that the terms of their fuel supply contracts do not permit the discussion of specific fuel prices, there was a general concern expressed about the high cost of fuels which are currently used.

Typical prices for alternative fuels have been made available by the Tasmanian Development Authority. On a $ per GJ basis, those fuels currently cost industrial users approximately:

Coal	$ 2.20 per GJ
Fuel Oil	$ 5.90 to $ 7.00 per GJ
Diesel	$13.20 per GJ
LPG	$13.50 to $16.80 per GJ

With natural gas prices at the process plant gate in the range of $2.90 to $4.60 per GJ, as determined in the R J Brown - CMPS preliminary engineering study for Yolla, natural gas is attractive relative to liquid fuels. Even with the inclusion of a distribution cost for natural gas, which would likely be in the order of 50¢ per GJ, the gas would be economically attractive to potential industrial customers along the north coast.

The price shown for coal represents the basic cost of the fuel supply alone. It does not include the relatively high cost associated with handling and stockpiling the coal, nor does its consider the problems and cost associated with ash disposal. Gas may well be a cost effective alternative to coal once all associated costs are included.

3. PROSPECTS FOR GAS-FIRED POWER GENERATION IN TASMANIA

3.1 Base Case Load Growth

The Hydro Electric Commission of Tasmania (HECT) has historically based its power generation facilities on hydro resources. Two schemes, the King River and Anthony, are currently under construction and are due to be commissioned in 1992 and 1994 respectively. Further undeveloped hydro resources are limited and are becoming less attractive due to economics, environmental concerns and long construction lead times.

The latest load forecast published by the HECT predicts that Tasmanian electricity consumption will grow at an average annual rate of 1.53%. This would result in the need for new generation capacity, after the commissioning of Anthony, by the winter of 1997. Figure 2 shows the growth in natural gas consumption which would correspond to fuel demand for a gas turbine commissioned to meet this increased generating capacity requirement.

If natural gas-fired turbines are included in the HECT's long term planning process, gas reserves at Yolla could provide approximately 13 PJ per year for a significant period of time to meet the gas demand. Figure 3 demonstrates the gas demand profile which would be realised if HECT were to contract for the purchase of 13 PJ of gas per year and base load associated generating facilities at a level designed to consume a minimum of 80% of the contracted gas volume. Such an operation would correspond to the running of one Frame 9 Gas turbine, as referred to in the Consultant's report, at a 90% capacity factor. The profile shown in Figure 3 corresponds closely to the gas sales forecast assumed in the R J Brown - CMPS Yolla Development Study for the Tasmanian market.

At an 8% discount rate, a discount rate typical of that used by the electricity industry, the Consultant's studies show that electricity can be generated at a cost of between 5.7¢ and 6.8¢ per kilowatt-hour using gas turbines as compared to 8.3¢ per kilowatt-hour with a new hydro scheme. This assumes a natural gas cost of $3.50 per GJ. Conversely, a gas turbine option would be economic relative to a hydro option with fuel costs of between $4.50 and $5.50 per GJ.

The above results are taken from the Consultant's report, 'Prospects for Gas-Fired Power Generation in Tasmania' which is included as Appendix A.

Detailed analysis of the economics of operating base load generating facilities fuelled by natural gas in preference to hydro plant may show that the long term savings which can be realised with gas make the operation depicted in Figure 3 economically viable. The additional up front cost to HECT of purchasing a minimum of 80% of the contracted gas volume may be more than compensated for by the future reduction in total generation cost. The work done to date has not included sufficient detail to accurately assess the impact of this mode of operation.

3.2 Load Growth with New Industrial Development

The base demand forecast shown in the Consultant's report indicates that HECT will require new generating capacity by 1997. This assumes a load growth which is consistent with historic trends, with some allowance for planned expansions by existing customers. There is no provision for major new industrial loads. Discussions with the Tasmanian Development Authority, and through the Authority with HECT, have indicated that it is reasonable to assume that demand would likely show higher growth than that indicated in the base demand forecast, with the addition of a new industrial load of 50 MW once every 5 years. A sensitivity has been examined which assumes that one such 50 MW load comes on-stream in 1994 and a second 50 MW load in 1997. Such new loads would advance the need for additional generating capacity so that commissioning of new plant would have to be co-incident with the start-up of the new industry.

Figure 4 shows the forecast of natural gas demand if such new industries were to eventuate. New generating capacity would have to be commissioned by 1995 in this case. New hydro capacity typically requires a lead time of 9 years and coal-fired thermal generation plants typically take 7 years to bring on-stream. Construction of hydro or coal-fire based plants would, therefore, have to begin immediately if they were to be commissioned in time to meet increased demand requirements. Natural gas-fired turbines, however, can usually be designed, constructed and commissioned in 3 years. Development of the Yolla gas field is forecast to take approximately 3 1/2 years. Project scheduling would therefore be similar to that required for the generating plant. It appears from this analysis that if Tasmania is to secure new major electricity consuming industries, gas is likely to provide the best prospects of meeting that demand. The establishment of industrial, commercial and domestic markets would also be advanced to correspond to the time at which natural gas would become available. This would indicate that an economically viable market for gas would develop well within the 15 year time frame specified by the terms of a Retention Lease.

NATURAL GAS FOR TASMANIA

Gas Market Development With New Industry & HECT Demand At Minimum Of 80%

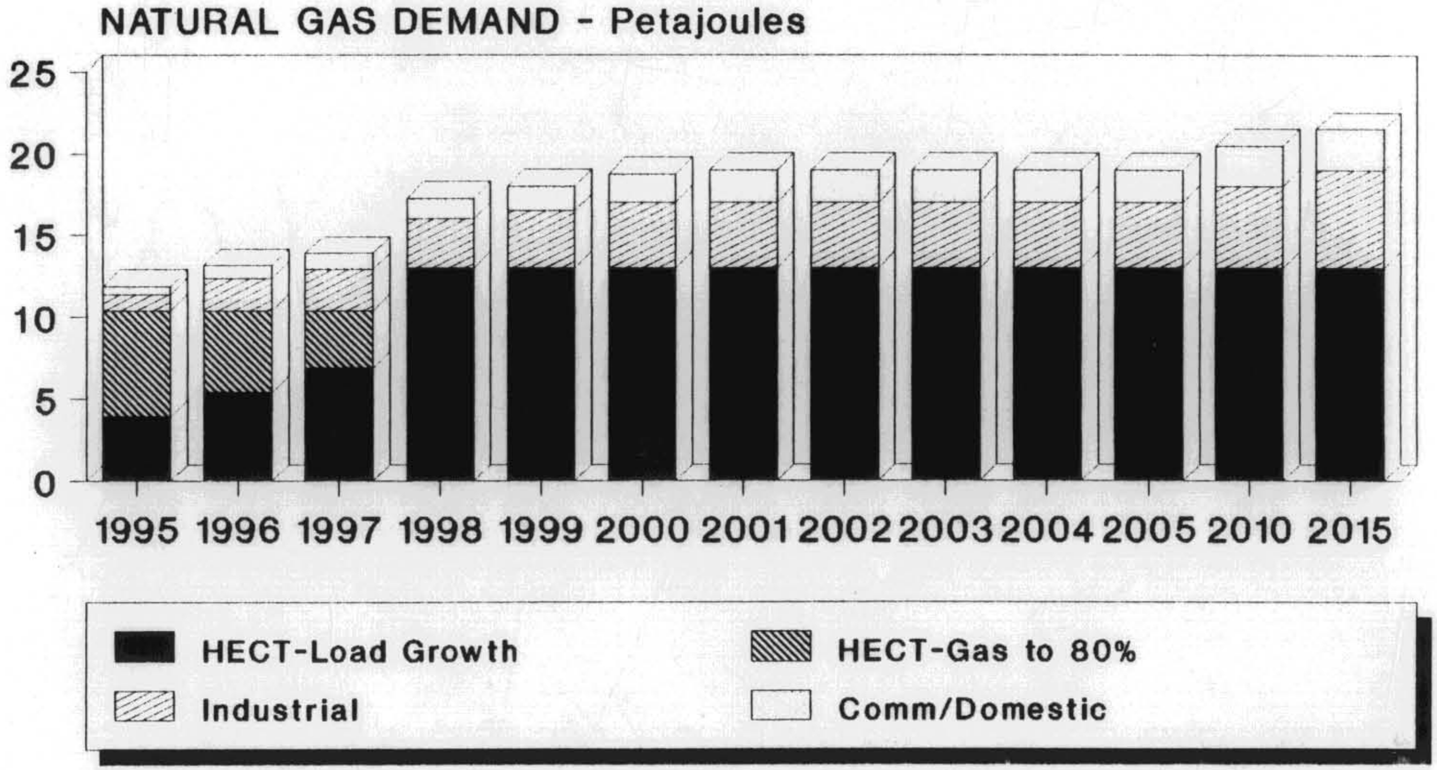

Figure 4

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NATURAL GAS MARKET DEVELOPMENT WITH NEW TASMANIAN INDUSTRIES

	Electricity Demand Growth	Industrial Users	Commercial /Domestic Users	Total
	PJ per year			
1995	3.9	1.0	0.5	5.4
1996	5.4	2.0	0.7	8.1
1997	6.9	2.5	1.0	10.4
1998	13.0	3.0	1.2	17.2
1999	13.0	3.5	1.5	18.0
2000	13.0	4.0	1.7	18.7
2001	13.0	4.0	2.0	19.0
2002	13.0	4.0	2.0	19.0
2003	13.0	4.0	2.0	19.0
2004	13.0	4.0	2.0	19.0
2005	13.0	4.0	2.0	19.0
2010	13.0	5.0	2.5	20.5
2015	13.0	6.0	2.5	21.5

NATURAL GAS MARKET DEVELOPMENT WITH NEW INDUSTRY & HECT DEMAND AT MINIMUM OF 80%

	Total With Normal Electricity Demand Growth	Additional HECT Demand to 80%	Total
	PJ per year		
1995	5.4	6.5	11.9
1996	8.1	5.0	13.1
1997	10.4	3.5	13.9
1998	17.2	0	17.2
1999	18.0	0	18.0
2000	18.7	0	18.7
2001	19.0	0	19.0
2002	19.0	0	19.0
2003	19.0	0	19.0
2004	19.0	0	19.0
2005	19.0	0	19.0
2010	20.5	0	20.5
2015	21.5	0	21.5

3.3 Bell Bay Conversion

The Bell Bay fuel oil-fired generating station is currently required as backup for the hydro plants. If the station were to be converted to natural gas and operated as a base load generation facility to meet growth in power demand then HECT would have to install a replacement thermal backup system. With the availability of gas, such a new system would likely be based on gas turbines and these would be operated in preference to a converted Bell Bay facility because of increased thermal efficiencies associated with new gas turbine technology.

Therefore, while the conversion of Bell Bay may increase gas demand during times of low rainfall or hydro plant maintenance, it would not create the base demand required to stimulate Yolla development. As a short-term option, however, a converted Bell Bay facility might provide base load capacity while a smaller gas-fired turbine was constructed to provide the necessary backup. The Bell Bay facility could then revert to its role as backup once sufficient load growth was established to justify the commissioning of more efficient gas turbines with similar output capacity.

4. OTHER POTENTIAL MARKETS

4.1 Commercial and Domestic Markets

With the establishment of a natural gas distribution system stretching from Smithton, along the north coast of Tasmania through Launceston to Bell Bay, as envisaged in Figure 1, gas could be made available to nearly half of Tasmania's population. Total energy consumption in commercial and domestic markets in Tasmania is in excess of 16 PJ per year with approximately half of this demand being met by thermal fuels, principally wood and wood waste. This indicates that natural gas could be competing for up to 4 PJ per year of thermal fuel demand in northern Tasmania in domestic and commercial markets.

Penetration of this market will depend on price, the convenience and advantage gas can offer with respect to reticulated supply and the promotion of natural gas' image as the clean alternative relative to other options. While the conversion of wood burning appliances to natural gas may present an obstacle, the relatively short life span of wood burning appliances could provide an opportunity for the introduction of gas as older systems are replaced.

4.2 New Applications for Natural Gas

While a scenario which justifies the development of Yolla can be formulated based on the use of natural gas in existing industries and for the generation of power, there is also potential for the establishment of industries which could add significantly to gas demand. Such markets would result in a lowering of the landed cost of gas or, alternatively, an increase in the profitability of the project.

Figure 5 shows a profile of the ultimate potential for natural gas demand in Tasmania. With natural gas used in both the transportation and petrochemical sectors, total demand could be well over 30 PJ per year. Proven and probable reserves at Yolla would not satisfy such a demand for a long time. Development of Yolla would, however, mean that a gas pipeline would be in place which crossed almost half of the distance between Tasmania and mainland Australia. Long term gas supplies could be assured by the continuation of that pipeline to tie in with the Victorian gas distribution system once Bass Basin reserves were depleted.

4.2.1 Transportation Fuels

The total demand for transportation fuels in Tasmania is in excess of 26 PJ per year, made up principally of requirements for automotive gasoline and diesel. A full 100% of these needs are met by imports into Tasmania. The development of Yolla could present a number of options for the mid 1990's for making an indigenous fuel source available to the Tasmania transportation sector.

Compressed Natural Gas

While still in the research and development phase, the use of compressed natural gas as a viable motor vehicle fuel is gaining acceptance on the mainland of Australia and around the world. The first, and potentially most significant, opportunity for compressed natural gas is as a replacement for diesel fuel in buses. State Transportation Authorities in many mainland states are presently conducting road tests in converted buses to study the benefits of natural gas. These tests could lead to the eventual conversion of entire bus transportation fleets.

Gas Conversion to Liquid Fuels

There are now a number of processes in various stages of development which use natural gas as a feedstock in the production of liquid transportation fuels. Some of the processes which have been publicised are:

* Synthetic gasoline is currently being produced from gas via methanol using Mobil technology at the New Zealand Synthetic Fuels Corporation project. The natural gas is used as a feedstock for the manufacture of methanol which is then converted into gasoline. Other processes for the production of synthetic gasoline are also in the development phase.

* The Shell Middle Distillate Synthesis Process has been developed to produce high-quality middle distillate fuel by catalytically converting gas to heavy long-chained hydrocarbon wax which can then be converted and fractionated into the principal motor fuel components. Plans are currently under way to construct the first commercial plant in Malaysia.

* Norway's Statoil has patented a catalytic process for the production of high-quality middle distillates which claims to have a very high conversion rate. Commercialisation of this process is unlikely to proceed before 1992.

With Tasmania's reliance on imports for all of its hydrocarbon fuels, such processes offer the potential to meet most of the state's fuel needs with indigenous supplies. A preliminary literature search suggests that approximately 13 PJ per year would be required to produce 4200 barrels of gasoline per day (with a total Tasmanian consumption of approximately 5500 barrels per day).

There would also be significant quantities of liquids produced in association with the natural gas from Yolla. Section 5 contains further information on how these liquids may fit into the Tasmanian marketplace.

4.2.2 Petrochemicals

There has been a proposal to have a feasibility study done by Davy McKee for the manufacture of ammonia using Yolla natural gas as a feedstock. The ammonia could then be used to produce nitrogenous fertilisers. A plant producing 650 tonnes per day of ammonia, an amount which would replace estimated imports into south-eastern Australia, would consume approximately 7 PJ per year. Appendix B is detailed outline of the Davy McKee proposal.

**ULTIMATE POTENTIAL GAS MARKET
WITH NEW TASMANIAN INDUSTRIES**

	HECT	Industrial Users	Commercial /Domestic Users	Petro Chemicals	Transportation Fuels	Total
	PJ Per year					
1995	10.4	1.0	0.5	0	0	11.9
1996	10.4	2.0	0.7	3.0	0	16.1
1997	10.4	2.5	1.0	6.0	4.0	23.9
1998	13.0	3.0	1.2	7.0	8.0	32.2
1999	13.0	3.5	1.5	7.0	12.0	37.0
2000	13.0	4.0	1.7	7.0	13.0	38.7
2001	13.0	4.0	2.0	7.0	13.0	39.0
2002	13.0	4.0	2.0	7.0	13.0	39.0
2003	13.0	4.0	2.0	7.0	13.0	39.0
2004	13.0	4.0	2.0	7.0	13.0	39.0
2005	13.0	4.0	2.0	7.0	13.0	39.0
2010	13.0	5.0	2.5	7.0	13.0	40.5
2015	13.0	6.0	2.5	7.0	13.0	41.5

5. ASSOCIATED LIQUIDS PRODUCTION

Condensate and crude oil will be produced in association with natural gas from Yolla at rates in the order of 3000 barrels per day, depending primarily on gas production rates. The high quality of these liquids means that, with minimal processing, liquid fuels could be made available directly to the Tasmanian market. At the indicated production rates, all of Yolla's liquid production could be absorbed within Tasmania. These liquids would enjoy a competitive advantage relative to fuels imported into Tasmania because of the high transportation costs associated with the imported fuels. The Southern Cross group has indicated that it is considering the construction of a small scale refinery on the north coast of Tasmania. The crude and condensate from Yolla would make an ideal feedstock for such a venture.

The use of these liquids would not be limited to the north coast of Tasmania. The infrastructure for transporting liquid fuels within the state is already well established.

The natural gas from Yolla will also contain LPG. With a gas production rate of 17 PJ per year, it is estimated that approximately 35,000 tonnes per year of LPG could be recovered if the economics justified the installation of the required separation and storage equipment. This is more than is currently consumed in Tasmania. * not so

6. NATURAL GAS - THE CLEAN ALTERNATIVE

With the growing awareness of the impact that the burning of fossil fuels has on the environment, the substitution of natural gas for coal, fuel oil, diesel and wood is becoming increasingly attractive for environmental reasons. The use of coal for power generation results in the emission of more than twice as much CO_2, one of the principal greenhouse gases, as does the combustion of natural gas for the same amount of energy. Similarly, the use of natural gas results in negligible SO_2 emissions and less than half the level of the NO_x emissions realised with the use of coal. While coal is generally considered to be the most environmentally offensive of the fossil fuels currently used in Tasmania, natural gas also compares very favourably with fuel oil, diesel and wood in this respect. Natural gas is the cleanest thermal fuel available for use in power generation.

The use of natural gas as a clean thermal fuel for industry and power generation is likely to have considerable appeal to the newly elected Tasmanian Government which comprises a coalition of Labor Party and independent "Green" representatives.

RELATIVE EMISSION LEVELS *

	COAL	NATURAL GAS
CO_2 (kt/y)	1300 (1650)	500 (950)
SO_2 (t/y)	5000 (2500)	< 5
NO_x (t/y)	3000	1150
Particulates (t/y)	130	8
Ash (kt/y)	100 (175)	0

* Based on 250 MW Power Station @ 70% Capacity
Using Typical Steaming Coal (Tas coal)

NATURAL GAS FOR TASMANIA

Ultimate Gas Market Potential

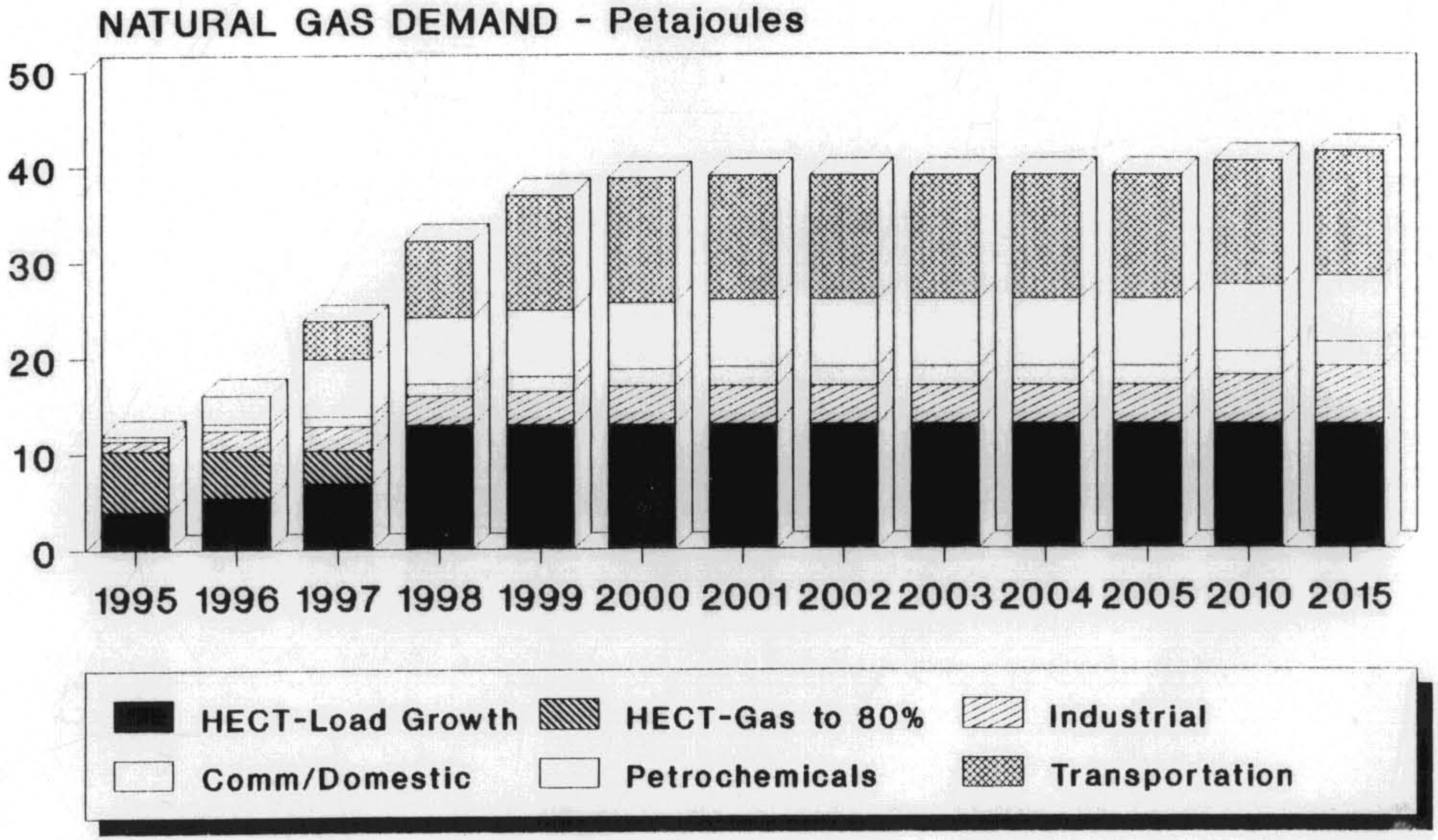

Figure 5

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APPENDIX A

PROSPECTS FOR GAS-FIRED POWER GENERATION IN TASMANIA

Prepared for

SAGASCO Resources Limited

September, 1989

P M Garlick & Associates Pty Ltd

In Association with NRG Pty Ltd

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EXECUTIVE SUMMARY.

SAGASCO Resources Limited (SAGASCO) is a member of a joint venture which has been undertaking a major exploration program for oil and gas in Bass Strait. In 1985, the group discovered the Yolla oil, gas and condensate field, approximately 135 km north of Burnie on the northern Tasmanian coastline. Tasmania is the only Australian State which does not have natural gas available to its population and industrial base.

The economic development of the Yolla field to supply Tasmania requires sufficient demand to provide an adequate rate of return on the capital investment. Major manufacturing and mineral processing plants on the Tasmanian north coast, which could benefit from a reliable natural gas supply, do not provide sufficient demand to justify development of the Yolla field.

The use of natural gas for power generation in Tasmania could provide the extra demand required to allow the gas field development to proceed. The Hydro Electric Commission of Tasmania (HECT) has historically based its power generation facilities on hydro resources. Two schemes, the King River and Anthony, are currently under construction and are due for commissioning in 1992 and 1994 respectively.

Further hydro resources are limited and becoming less economic, as well as being subject to environmental concerns. As well as hydro, the HECT has examined the possibility of a coal-fired thermal power station in the Fingal Valley and a high voltage undersea transmission cable to Victoria. Natural gas fired power developments could well provide the most economic answer to Tasmania's future growth in electricity demand.

Electricity supply in Tasmania is characterised by substantial sales to eighteen major industrial consumers, a number of which were attracted to Tasmania by low electricity tariffs on long term contract. Approximately half of the system peak demand and two thirds of the energy sales are currently created by these major industrial consumers.

The latest load forecast by the HECT, as published in the 1987/88 Annual Report, predicts that electricity consumption will grow only slowly after 1987/88 at an average annual rate of 1.53%. To meet the energy needs of the Tasmanian system, new plant after Anthony is indicated to be required by the winter of 1997, so as to be available for 1997/98.

Additional new industries could result in a sudden urgent need for new plant capacity. New hydro capacity would typically require a lead time of 9 years, and there are now only 8 years before the winter of 1997. A new coal-fired station would typically need at least 7 years if site and environmental approvals have not yet been obtained. Gas turbine plant, however, can usually be designed and installed on a 3 year lead time.

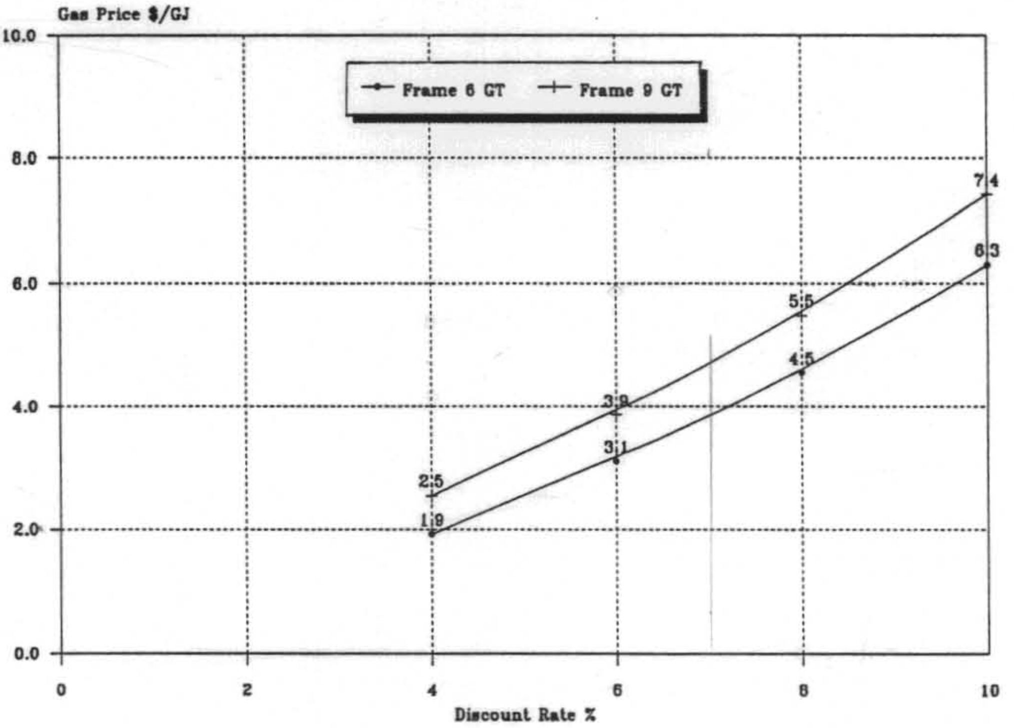
There is a possibility that additional industrial loads could develop in the minerals processing area as early as 1994. As a special case, the study examined two new additional industrial loads, each of 50 MW demand, to be installed in mid 1994 and 1997.

It is concluded that installation of new generating plant would be required coincident with the new industrial loads. A single 116MW Frame 9 Gas Turbine would be a suitable choice for plant to serve each new industrial plants.

472380

Electricity Unit Cost Generation Option.	Discount 4% c/kWh	Rate 6% c/kWh	8% c/kWh	10% c/kWh
Frame 6 GT 34MW	6.32	6.55	6.81	7.09
Frame 9 GT 116MW	5.39	5.53	5.68	5.85
Coal-Fired 200MW	6.28	7.16	8.17	9.32
New Hydro 83MW	4.14	5.99	8.25	10.93
Bass Str. Cable 300MW	6.32	7.53	8.88	10.36

BREAK EVEN GAS PRICE AGAINST HYDRO
(Hydro at 50% Capacity Factor)



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If new industrial projects prove to be realistic in the assumed timeframe, then gas-fired plant could be the only choice because of the short lead time. There would be insufficient time for new hydro projects to be constructed by 1994. It is doubtful at this stage if there would be time for coal-fired plant to be constructed, and the preferred unit size of 200MW is much larger than would be required.

The HECT must therefore be approaching a time when decisions will need to be made on future generation strategies. Gas-fired plant based on the Yolla gas discovery would be well placed to satisfy Tasmania's future electricity needs.

This study examined the economics of two sizes of gas turbine (34MW and 116MW) against the other generation options available for Tasmania. The other options examined were a 2x200MW coal-fired station, a notional new hydro option of 83MW and a 300MW capacity high voltage cable to the mainland.

The results of the study are shown in the table opposite, which shows unit costs of supply for the options when operating at 50% capacity factor. These results assume a delivered gas price of $3.50/GJ.

The hydro option would be constrained to operate at no more than 50% capacity factor by water availability. By comparison the thermal options would only be constrained by plant availability.

The gas turbines are the lowest cost options by a significant margin at normal electricity industry discount rates (7% to 8%). New hydro is only economic at discount rates below 5%. The coal-fired option and the Bass Strait cable are not economic compared to the large gas turbine option at any discount rate.

Break-even gas prices against the hydro option are again very sensitive to discount rate as can be seen in the figure opposite. A discount rate of 8%, which is consistent with electricity industry practice, gives break-even gas prices of $4.50 to $5.50/GJ for the two gas turbine options.

In summary, break-even gas prices are $4/GJ or higher for all options, with lower break-even prices only realised at lower discount rates and higher capacity factors than would normally be considered reasonable.

The prospects for use of gas for Tasmanian electricity production are therefore good if gas can be delivered for $3.50 to $4.00/GJ. Gas options also have advantages with shorter lead times, and lower capital outlays. Environmentally gas turbines would have lower emissions of carbon dioxide (a greenhouse gas) than coal-fired plant and would not threaten forested areas like hydro.

472382

1 INTRODUCTION.

SAGASCO Resources Limited (SAGASCO) is a member of a joint venture which has been undertaking a major exploration program for oil and gas in Bass Strait. The other members of the joint venture are Amoco, the Bass-Cue Group, Romsey Resources and Southeastern Petroleum.

In 1985, the group discovered the Yolla oil, gas and condensate field, approximately 135 km north of Burnie on the northern Tasmanian coastline. Tasmania is the only Australian State which does not have natural gas available to its population and industrial base.

The economic development of the Yolla field to supply Tasmania requires sufficient demand to provide an adequate rate of return on the capital investment. There are a number of major manufacturing and mineral processing plants on the Tasmanian north coast, which could benefit from a reliable natural gas supply. These industries alone do not provide sufficient demand to justify development of the Yolla field.

The use of natural gas for power generation in Tasmania could provide the extra demand required to allow the gas field development to proceed. The Hydro Electric Commission of Tasmania (HECT) has historically based its power generation facilities on hydro resources. HECT also installed a 2x120 MW oil-fired thermal plant at Bell Bay in the early 1970's, to provide energy support in the event of extended drought.

Development of further hydro resources is becoming less economic as well as being subject to environmental concerns. For the future, the HECT has examined the possibility of a coal-fired thermal power station in the Fingal Valley and a high voltage undersea transmission cable to Victoria. Natural gas fired power developments could well provide the most economic answer to Tasmania's future growth in electricity demand.

SAGASCO is interested in the potential for gas-fired power generation in Tasmania. In June 1989, the Company requested a proposal from **P M Garlick & Associates Pty Ltd**, specialist Australian energy consultants, for a study to examine such prospects. The Consultants decided to secure the involvement of **NRG Pty Ltd**, specialists in power plant procurement and project management, to assist in the project. The Consultant's Proposal dated 29 June 1989 was subsequently accepted by the Company on 4 August 1989.

Chapter 2 of the report covers the existing structure and operation of the HECT electricity system and projected developments. Chapter 3 examines the system planning aspects of load forecasts and possible timing of new plant additions.

Chapter 4 covers new generation options and Chapter 5 presents the economic evaluation of alternatives, including the break-even prices at which natural gas would be competitive with the non gas-fired alternatives. The conclusions of the report are contained in the Executive Summary.

472383

2 BASE DATA AND SYSTEM OPERATION.

2.1 System Overview.

The Hydro-Electric Commission of Tasmania (HECT) is responsible for generation, transmission and distribution throughout Tasmania to 212,000 customers. It operates a high voltage transmission system at 220 kV and 110 kV. Staff numbers totalled 4153 at mid 1988.

The highest peak load recorded to 1988 was 1346 MW in July 1987. Energy sales in 1987/88 (the year ended 30 June 1988) totalled 8119 GWh, an increase of 5.7% over the previous year. The Tasmanian system operates at a load factor of around 75%, reflecting the high proportion of heavy industrial loads in the State.

Tasmanian electricity generation capacity in 1988 comprised 2316 MW of generating plant as set out in Table 2.1. In addition, small diesel generators supply energy on King and Flinders Islands and HECT imports energy from NW Acid Pty Ltd (thermal) and Mt Lyell.

The major energy source in Tasmania is hydro-electric energy from 25 hydro-electric power stations currently in service. In 1987/88, the hydro power stations generated over 99% of Tasmania's electricity, while the remainder came from the HECT's oil-fired 2x120 MW Bell Bay Power Station (2.6% capacity factor) and co-generation plant operated by industry.

There are five major hydro-electric schemes with a total capability of 2,076 MW which draw on substantial hydro resources available mainly from the western half of the island. Energy storage dams are located at the head of each of the five schemes with power stations and regulating storages in cascade along each of the rivers involved. The five schemes and their generating capabilities at the end of 1988 were:

- Derwent	514 MW
- Great Lake	430 MW
- Mersey-Forth	308 MW
- Gordon	432 MW
- Pieman	392 MW

The hydro schemes are a mix of run of river and storage schemes. The size of the hydro storages have been selected to ensure that the generating plants can meet daily and seasonal electrical load variations through a wide range of possible rainfall patterns. Bell Bay Power Station provides a thermal backup in case extended dry weather requires that the level in hydro storages be maintained within operational ranges.

TABLE 2.1 - TASMANIAN POWER STATIONS IN SERVICE - 1988.

Hydro Scheme	Power Station	Generating Units	Total Capacity MW	Install Date
Derwent	Tarraleah	6 x 15	90	1938
	Butlers Gorge	1 x 12	12	1951
	Tungatinah	5 x 25	125	1953
	Lake Echo	1 x 32	32	1956
	Wayatinah	3 x 13	38	1957
	Liapootah	3 x 28	84	1960
	Catagunyah	2 x 24	48	1962
	Meadowbank	1 x 40	40	1967
	Repulse	1 x 28	28	1968
	Cluny	1 x 17	17	1968
Great Lake	Waddamana B	4 x 12	48	1944
	Trevallyn	4 x 20	80	1955
	Poatina	6 x 50	300	1964
	Tods Corner	1 x 2	2	1966
Mersey-Forth	Rowallan	1 x 10	10	1968
	Lemonthyme	1 x 51	51	1969
	Devils Gate	1 x 60	60	1969
	Wilmot	1 x 31	31	1971
	Cethana	1 x 85	85	1971
	Paloona	1 x 28	28	1972
	Fisher	1 x 43	43	1973
Gordon	Gordon 1 & 2	2 x 144	288	1978
	Gordon 3	1 x 144	144	1988
Pieman	Mackintosh	1 x 80	80	1982
	Bastyan	1 x 80	80	1984
	Reece	2 x 116	232	1986
Total Hydro			**2,076**	
Thermal	Bell Bay	2 x 120	240	1971 1975
Total			**2,316**	

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2.2 System Operation.

Electrical energy production in Tasmania is almost completely supplied by the HECT's hydro electric power stations. In 1987/88, these power stations contributed approximately 99% of the State's electricity demand. An overview of system operation for 1987/88 is presented below.

Maximum Demand	MW	1346
Energy Generated HECT Hydro HECT Thermal **Total**	GWh	 8728 55 8783
Load Factor	%	74.5
Energy Sold	GWh	8119
Loss Factor	%	7.6
Effective Capacity HECT Hydro HECT Thermal **Total**	MW	 2075 240 2315
Capacity Factor	%	43.3
Reserve Plant Margin	%	72.0

The Tasmanian electricity system comprises five essentially independent hydro schemes. The five schemes operate in parallel and it is not possible to transfer water between them, except for a limited transfer capability between the Great Lake and the lower end of the Derwent scheme. Two of the schemes, the Gordon and Great Lake have very large (major) storages; the Derwent has a medium storage; and the Mersey-Forth and Pieman schemes have only minor storages and can be regarded as run of river. Table 2.2 below summarises available production and storage for each of the schemes.

Another indication of the storage sizes can be obtained by dividing the storage volume by the average rainfall yield. This is shown in Table 2.3 for the larger storages.

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TABLE 2.2 - HYDRO-ELECTRIC SCHEMES IN TASMANIA - 1988

Hydro Scheme	Storage Type	Installed Capacity (MW)	Average Yield (MWav)	Storage Time (Note 1)
Derwent	medium	514	374	5.2 months
Great Lake	major	430	205	1.9 years
Mersey-Forth	run of river	308	122	39 days
Gordon	major	432	203	1.2 years
Pieman	run of river	392	196	23 days
Total		**2,076**	**1,100**	

Note 1. Storage time is obtained by dividing total storage capacity by the installed capacity of stations in each scheme. This may be misleading, especially for run of river schemes with cascading of storages (i.e. stations in series). For the Derwent, Mersey-Forth and Pieman schemes the effective storage times are some two to three times the quoted values.

TABLE 2.3 - STORAGE VOLUME TO YIELD RATIOS.

Hydro Scheme	Storage	Vol/Yield Ratio (yrs)
Gordon	Gordon	3.09
Great Lake	Great Lake	4.38
Derwent	Lake St. Clair - King William	0.79
Derwent	Lake Echo	2.31
Derwent	Tungatinah	0.09
Mersey-Forth	Lake Rowallen	0.24
Mersey-Forth	Lake MacKenzie	0.15

Rainfall patterns in Tasmania show a marked seasonal dependence, the wettest months (July to September) occurring during winter and the driest (January to March) occurring in summer. There is also significant variability in rainfall from year to year. This variability is the principal factor guiding the policy for operating the Tasmanian system. This is best understood by first considering the operation of the run-of-river systems.

During the wetter parts of the year, the run-of-river stations (Mersey-Forth and Pieman) must be operated at full capacity to avoid spill (which represents an irrecoverable energy loss). In the drier months the output from these stations inevitably drops away and system energy must be made up by other stations. Some Derwent storages allow the Derwent stations to extend operation over most of the year. As a general rule, the wetter months must be approached with the headwater catchments relatively low, to allow heavy rains to be captured without spill.

The large storage schemes (Gordon and Great Lake) operate to fill in the demand which cannot be met by the run-of-river schemes. In the wetter months, storage levels rise because of high water inflows and low or zero generation, due to high run-of-river station output. As output from the run-of-river stations is reduced, output from the larger storage schemes increases to compensate. Thus in the summer months, levels in the large storages will tend to fall as inflow is low and generation is high.

Levels in the large storage schemes also fluctuate between years because of yearly rainfall variations. These variations have a direct effect on the water inflows into the large storages, and an indirect effect because large storage scheme generation must compensate for variations in annual run-of-river scheme output. In addition, the average load on the system will vary from year to year. The large storages are sized and operated to allow for these factors.

However, there will always be the possibility of spill or water shortages. These dictate an operating policy favouring intermediate storage operating levels in normal times. When storage levels are low, thermal plant at Bell Bay can be operated to reduce the water draw. Because thermal operating costs are relatively high, Bell Bay is regarded as backup rather than base load plant, even though it can operate for extended periods when called upon.

The mixture of run-of-river and large storage hydro plant dictates that a certain reserve of generating capacity be maintained. While hydro generating plant is highly reliable, their water supply is much less so. In an extremely dry sequence of years, the output from all run-of river schemes, including the Derwent, could drop to very low levels.

In broad terms, this means that a capacity margin of similar size to the total capacity of the run of river schemes (about 1200 MW at present) must be maintained in the rest of the system. The Gordon scheme has been designed to allow new generators to be installed to meet this requirement, and Bell Bay provides a further backup.

2.3 Projected Developments.

New hydro developments already under construction comprise King River, with a capacity of 144 MW (68 MWav), scheduled for completion in 1992, and Anthony, with a capacity of 83 MW (30 MWav), due for completion in 1994. In addition, Anthony will result in an extra 14 MWav being available from the Pieman scheme. A third 144 MW unit was installed on the Gordon scheme in 1988, increasing the scheme's generating capacity but not the energy capability. With completion of these developments, total installed capacity in Tasmania will be 2542 MW (2302 MW hydro, 240 MW thermal) with a long term average yield of 1392 MWav (1212 MWav hydro, 180 MWav thermal).

Further developments contemplated include the addition of two more 144 MW sets on the Gordon (possibly around year 2000) which will provide new capacity but no additional energy. Investigations are continuing to define the cost and scope of further hydroelectric options such as the Lower King, Que, Lake Augusta and King Racelines schemes; and potential redevelopment of existing schemes at Lake Margaret and Tarraleah (1987/88 Annual Report).

Notwithstanding these potential hydro developments, the HECT, in a report to the Tasmanian Government in August 1983, foreshadowed the development of a 2x200 MW coal-fired thermal station using Tasmanian coal to follow the Anthony and King schemes. Subsequent reviews of potential load growth on the Tasmanian system have deferred this extra capacity.

3 SYSTEM PLANNING.

3.1 Load Forecasts.

Tasmanian electricity total system peak demand and energy generated for the ten years to 1987/88 are shown below in Table 3.1.

TABLE 3.1 - TASMANIAN MAXIMUM DEMAND AND ENERGY GENERATED - 1979-1988

Fiscal Year	Annual Max. Demand		Annual Energy Generated			Load Factor
	MW	% Inc	GWh	MW avg	% Inc	%
1979	1159		7645	873		75.3
1980	1151	-0.7	7803	891	2.1	77.4
1981	1225	6.4	7951	908	1.9	74.1
1982	1241	1.3	8036	917	1.1	73.9
1983	1297	4.5	7894	901	-1.8	69.5
1984	1273	-1.9	8059	920	2.1	72.3
1985	1312	3.1	8194	935	1.7	71.3
1986	1319	0.6	8328	951	1.6	72.1
1987	1326	0.5	8319	950	-0.1	71.6
1988	1346	1.5	8783	1003	5.6	74.5
Annual Avge. Incr.		**1.7**			**1.6**	

Electricity supply in Tasmania is characterised by substantial sales to eighteen major industrial consumers, a number of which were attracted to Tasmania by low electricity tariffs on long term contract. Approximately half of the system peak demand and two thirds of the energy sales are currently created by these major industrial consumers.

The Comalco aluminium smelter at Bell Bay (240 MW) and the works of the Electrolytic Zinc Co at Risdon and Rosebery (190MW) are the largest of the major industrial consumers. Retail electricity sales to the main consumer classes over the ten years to 1987/88 are shown in Table 3.2.

The high proportion of industrial loads on the Tasmanian system has resulted in the relatively high load factors shown above. Load factor is the relationship between average demand and maximum demand and provides a measure of the utilisation level of the system.

TABLE 3.2 - TASMANIAN ELECTRICITY SALES BY CATEGORY - 1979-1988

Fiscal Year	Domestic (1)		Commercial (2)		General Industrial (3)		Major Industrial (4)		TOTAL	
	GWh	% inc	GWh	% inc	GWh	% inc	GWh	% inc	GWh	% inc
1979	1462		180		652		4709		7003	
1980	1538	5.2	191	6.1	691	5.9	4760	1.1	7180	2.5
1981	1569	2.0	197	3.1	710	2.7	4716	-0.9	7191	0.2
1982	1662	5.9	235	19.3	599	-15.6	4900	3.9	7396	2.9
1983	1672	0.6	251	6.9	558	-6.8	4772	-2.6	7253	-1.9
1984	1693	1.3	258	2.7	596	6.7	4849	1.6	7395	2.0
1985	1733	2.4	270	4.6	558	-6.4	4943	1.9	7504	1.5
1986	1762	1.7	285	5.6	600	7.7	5029	1.7	7677	2.3
1987	1821	3.3	302	6.1	613	2.2	4944	-1.7	7681	0.1
1988	1768	-2.9	322	6.7	647	5.4	5382	8.9	8119	5.7
Annual Avge. Incr.		**2.1**		**6.7**		**0.5**		**1.5**		**1.7**

Note:

(1) Includes Residential, Hot Water and Off Peak.

(2) Includes Commercial and Bulk Commercial.

(3) Includes Industrial, Unread Meters, and HECT Villages.

(4) Includes Major Industrial Customers only.

HECT's various tariffs have not allowed an accurate division of sales statistics into the categories shown in Table 3.2. The different tariffs included in each category are shown in the Note appended to the Table. In 1987/88, HECT revised the tariff structure, so figures for that year are not exactly comparable with the previous years. Despite these limitations, the statistics do provide a reasonable picture of growth patterns over the period.

Rates of growth in electricity demand have been variable over the last ten years, particularly in the industrial sector. The recession of 1981/82 saw a significant reduction in industrial sales, and this sector has only recently been showing a recovery. Growth in the commercial sector has been more sustained, while domestic sector sales for heating are sensitive to weather conditions.

The variability in load growth has caused a degree of uncertainty in forecasts of future load growth trends. The actual annual rate of growth since 1979 of 1.7% has been much less than HECT forecasts made at that time. Those HECT forecasts assumed growth of 2.9% to 1982, declining to 2.7% by 1986 and remaining at 2.7% thereafter.

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The latest load forecast by the HECT, as published in the 1987/88 Annual Report, predicts that electricity consumption will grow only slowly after 1987/88 at an average annual rate of 1.53%. These forecasts of demand and energy are shown in Table 3.3.

TABLE 3.3 - FORECASTS OF MAXIMUM DEMAND AND ENERGY GENERATED - 1987-2000

Fiscal Year	**Annual Max. Demand**		**Annual Energy Generated**			**Load Factor**
	MW	**% Inc**	**GWh**	**MW avg**	**% Inc**	**%**
1987	1326	0.5	8319	950	-0.1	71.6
1988	1346	1.5	8783	1003	5.6	74.5
1989	1409	4.7	9044	1032	3.0	73.3
1990	1476	4.7	9312	1063	3.0	72.0
1991	1500	1.6	9476	1082	1.8	72.1
1992	1524	1.6	9643	1101	1.8	72.2
1993	1548	1.6	9813	1120	1.8	72.4
1994	1573	1.6	9986	1140	1.8	72.5
1995	1598	1.6	10162	1160	1.8	72.6
1996	1616	1.1	10276	1173	1.1	72.6
1997	1635	1.1	10392	1186	1.1	72.6
1998	1653	1.1	10510	1200	1.1	72.6
1999	1672	1.1	10628	1213	1.1	72.6
2000	1691	1.1	10749	1227	1.1	72.6

The above forecast could be regarded as optimistic as relatively high rates of growth will be required in 1988/89 and 1989/90 to meet the 1989/90 forecast point. Also the energy growth rate of 1.8% between 1990 and 1995 is slightly higher than the average rate of growth over the ten years to 1988.

However, given the uncertainty of new industrial developments in Tasmania, these forecasts provide a reasonable basis for estimating the timing for new plant additions. This issue is addressed in the next Sub-Section.

3.2 Timing for New Plant.

Timing for the commissioning of new generating units is dictated by the need to maintain an adequate level of supply reliability. It is necessary to balance the cost of new plant additions against the increased risk of power restrictions and/or blackouts from reducing reserve plant margins.

Reserve plant is needed on any electricity system to provide continuity of supply in the event of plant outages for maintenance or forced outages due to plant failures. The level of plant reserves is called the Reserve Plant Margin and it is normally expressed as the percentage of generating capacity above maximum demand.

Generating plant must meet both system peak demands and the energy needs of the system. Hydro plant is normally very reliable so that meeting peak demands is usually not a problem. However hydro is also energy constrained by the availability of water, which can be extremely variable in the case of run of river schemes.

Hydro system energy yields can be conveniently considered as an assured yield (firm energy) and as an average yield (firm plus non-firm energy). The assured yield is assessed as the summation of the runoff yield during an extended dry weather period (from historical records) and the yield available from storage drawdown over the same period. The average yield is assessed as the long period average runoff yield, which reflects average weather conditions.

The Tasmanian electricity system, with its mix of run of river and storage schemes, has substantial reserves of spare generating capacity to meet short term peak demands. The availability of energy is therefore the main requirement which dictates the need for additional generating units, particularly with Tasmania's relatively high load factor.

At the present time, the HECT is constructing the King River and Anthony hydro schemes. The King River unit is timed for commissioning in March 1992, and will be available to meet peak demands in the winter of 1992 and the energy needs of 1992/93. The Anthony unit is to be commissioned in mid 1994 and will provide energy in 1994/95.

The "Base" HECT Load Forecast.

Table 3.4 shows reserve plant margins up until the year 2000, derived from the HECT "base" forecast of system peak demands and the scheduled commissioning dates for King River and Anthony. The Table shows that reserve plant margin is relatively high (64.3%) at the present time following the commissioning of the Gordon No 3 144 MW unit in 1988.

RPM will fall to approximately 55% just prior to the commissioning of King River in 1992. It will then increase to approximately 61% with the King River and Anthony commissioning, and then decline to 50% by the year 2000, provided no additional plant is installed.

Table 3.5 shows energy reserve margins up until the year 2000, also derived from the HECT "base" forecast of system energy demands and the scheduled commissioning dates for King River and Anthony. The Table shows total energy reserve margin, which includes a notional energy capacity of 180 MW average for Bell Bay, and hydro only energy reserve margin.

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TABLE 3.4 - FORECAST RESERVE PLANT MARGINS - 1987-2000. "BASE" HECT LOAD FORECAST.

Fiscal year	Max. Demand	Plant Capacity	Reserve Plant Margin	
	MW	MW	%	MW
1987	1326	2171	63.7	845
1988	1346	2315	72.0	969
1989	1409	2315	64.3	906
1990	1476	2315	56.8	839
1991	1500	2315	54.4	815
1992	1524	2459	61.4	935
1993	1548	2459	58.8	911
1994	1573	2542	61.6	969
1995	1598	2542	59.1	944
1996	1616	2542	57.3	926
1997	1635	2542	55.5	907
1998	1653	2542	53.8	889
1999	1672	2542	52.0	870
2000	1691	2542	50.3	851

HECT have generally timed new plant additions to ensure that hydro system assured yields have matched electricity system energy demand. Thus, under average rainfall conditions, operation of Bell Bay is not required other than for staff training and on isolated occasions to cover hydro plant maintenance or repair. Assured yield on the combined HECT systems is approximately 96% of average yield, because of the large storages in the Gordon and Great Lakes schemes. Non firm hydro energy and the energy potential of Bell Bay represent the energy reserve margin above demand.

This is consistent with the hydro energy reserve margins shown in Table 3.5, which can be seen to decline to 1.5% in 1991/92, at which point King River is scheduled for commissioning. Hydro energy reserve then declines to 1.9%, just prior to commissioning of Anthony.

Based on this criteria, new plant after Anthony will be required to be commissioned by the winter of 1997, so as to be available for 1997/98. This date could be deferred by a year if it was decided to take the risk that the hydro storages could be drawn down over 1997/98 (if below average rainfall yield occurs) and that Bell Bay could provide supplementary generation.

Prudency indicates that HECT would be unlikely to take such a risk, particularly as there is always the additional risk of project construction delays. All of this depends on the validity of the load forecasts, which must be regarded as uncertain because of the potential for large variations in the demands of major industrial consumers.

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TABLE 3.5 - FORECAST ENERGY RESERVE MARGINS - 1987-2000.
"BASE" HECT LOAD FORECAST.

Fiscal year	Annual Energy Generated		Total Energy Capac	Total Energy Reserve	Hydro Energy Capac	Hydro Energy Reserve	
	GWh	MW Avg	MW Avg	%	MW Avg	%	MW Avg
1987	8319	950	1259	32.6	1079	13.6	129
1988	8783	1003	1280	27.7	1100	9.7	97
1989	9044	1032	1280	24.0	1100	6.6	68
1990	9312	1063	1280	20.4	1100	3.5	37
1991	9476	1082	1280	18.3	1100	1.7	18
1992	9643	1101	1297	17.8	1117	1.5	16
1993	9813	1120	1348	20.3	1168	4.3	48
1994	9986	1140	1348	18.3	1168	2.5	28
1995	10162	1160	1392	20.0	1212	4.5	52
1996	10276	1173	1392	18.7	1212	3.3	39
1997	10392	1186	1392	17.3	1212	2.2	26
1998	10510	1200	1392	16.0	1212	1.0	12
1999	10628	1213	1392	14.7	1212	-0.1	-1
2000	10749	1227	1392	13.4	1212	-1.2	-15

New Industrial Loads.

Additional new industries could result in a sudden urgent need for new plant capacity. New hydro capacity would typically require a lead time of 9 years, and there are now only 8 years before the winter of 1997. A new coal-fired station would typically need at least 7 years, if site and environmental approvals have not yet been obtained. Gas turbine plant, however, can usually be designed and installed on a 3 year lead time.

There is a possibility that additional industrial loads could develop in the minerals processing area as early as 1994. As a special case, new industrial loads have been added to the base load forecast, in order to see the effect on the need for new generating capacity.

These new industrial loads comprise a plant with 50 MW maximum demand to be installed in mid 1994, followed in mid 1997 by a further 50 MW demand plant. The plants are assumed to operate with a load factor of 95%, which is typical for minerals processing plants operating three shifts per day, seven days a week. The energy demand for each plant is therefore 47.5 MW average.

Table 3.6 shows energy reserve margins up until the year 2000, derived from the HECT "base" forecast of system energy demands, but including the new industrial loads in 1994/95 and 1997/98. The scheduled commissioning dates for King River and Anthony are unchanged. The Table, as before, shows total energy reserve margin, which includes a notional energy capacity of 180 MW average for Bell Bay, and hydro only energy reserve margin.

TABLE 3.6 - FORECAST ENERGY RESERVE MARGINS - 1987-2000.
WITH NEW INDUSTRIAL LOADS.

Fiscal year	Annual Energy Generated		Total Energy Capac	Total Energy Reserve	Hydro Energy Capac	Hydro Energy Reserve	
	GWh	MW Avg	MW Avg	%	MW Avg	%	MW Avg
1987	8319	950	1259	32.6	1079	13.6	129
1988	8783	1003	1280	27.7	1100	9.7	97
1989	9044	1032	1280	24.0	1100	6.6	68
1990	9312	1063	1280	20.4	1100	3.5	37
1991	9476	1082	1280	18.3	1100	1.7	18
1992	9643	1101	1297	17.8	1117	1.5	16
1993	9813	1120	1348	20.3	1168	4.3	48
1994	9986	1140	1348	18.3	1168	2.5	28
1995	10578	1207	1392	15.3	1212	0.4	5
1996	10692	1221	1392	14.0	1212	-0.7	-9
1997	10808	1234	1392	12.8	1212	-1.8	-22
1998	11342	1295	1392	7.5	1212	-6.4	-83
1999	11460	1308	1392	6.4	1212	-7.4	-96
2000	11581	1322	1392	5.3	1212	-8.3	-110

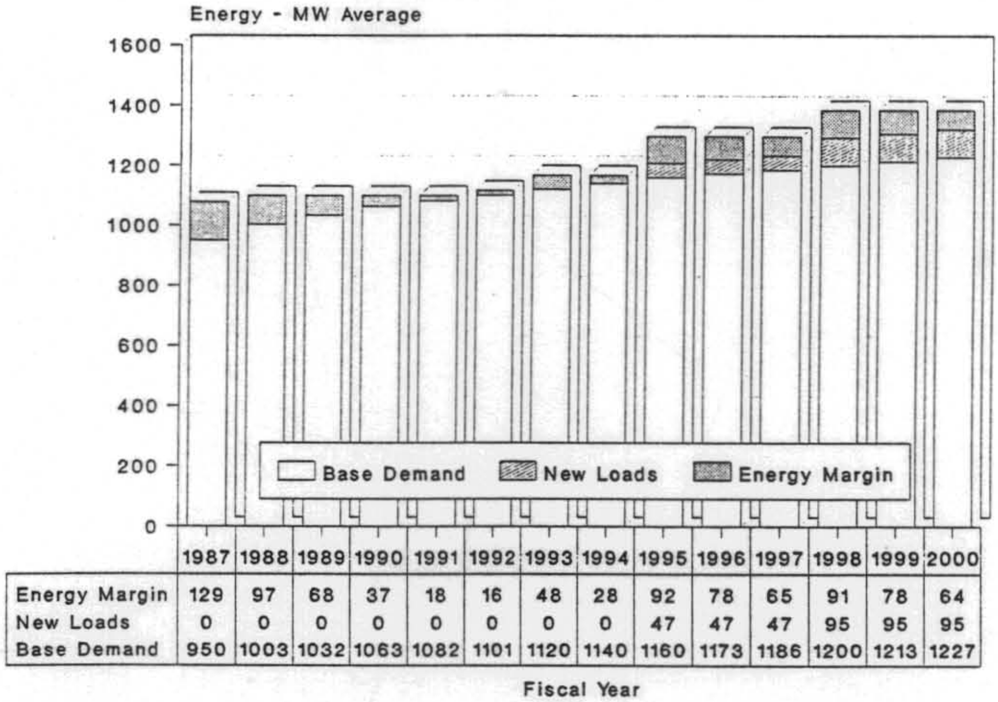
On the criterion that hydro energy reserve margin should not be less than 1% to 2%, additional new generating plant is indicated to be required to coincide with the commissioning dates of the new industrial loads i.e. mid 1994 and mid 1997. As King River and Anthony are intended to meet the "base" system load growth, it is fairly obvious that additional plant would be required to cover any new industrial loads above the "base" load growth expectations.

Desirably the additional plant capacity should be sufficient to meet the energy needs of each new 50 MW industrial load. This infers a unit capacity in the order of 70MW, or multiple units of the same total capacity. Economics would normally favour a single large unit.

Figure 3.1 shows "base" energy demand, new industrial loads and energy reserve margins on the assumption that single large 116MW gas turbines are installed to serve each new industrial load in 1994 and 1997. This size of gas turbine is the largest currently available.

FIGURE 3.1 - ENERGY RESERVE MARGINS

New Industrial Loads Mid 1994 and 1997



	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Energy Margin	129	97	68	37	18	16	48	28	92	78	65	91	78	64
New Loads	0	0	0	0	0	0	0	0	47	47	47	95	95	95
Base Demand	950	1003	1032	1063	1082	1101	1120	1140	1160	1173	1186	1200	1213	1227

Note: Energy Margin excludes Bell Bay PS

Although gas turbines of 116 MW size are somewhat larger than strictly necessary, economies of scale could make them an economic choice. The energy reserve margins resulting from their installation are reasonable and comparable with energy reserve margins on the HECT system over the last few years.

If new industrial projects prove to be realistic in the assumed timeframe, then gas-fired plant could be the only choice because of short lead times. There would be insufficient time for new hydro projects to be constructed by 1994. It is doubtful at this stage if there would be time for coal-fired plant to be constructed, and the preferred unit size of 200MW is much larger than would be required.

The HECT must therefore be approaching a time when decisions will need to be made on future generation strategies. Gas-fired plant based on the Yolla gas discovery could be well placed to satisfy Tasmania's future electricity needs. This will also depend on the economics of gas-fired plant compared to other alternatives. This issue is examined in the next Chapter.

4 NEW GENERATION OPTIONS.

4.1 Gas Turbines.

Natural gas-fired gas turbines are now a common feature of a number of Australia's electricity systems. In the late 1970's, the State Electricity Commission of Victoria (SECV) installed seven gas turbines, with 465MW total capacity, at Jeeralang in the Latrobe Valley. These gas turbines use natural gas from the Bass Strait offshore oil and gas fields controlled by Esso/BHP. They can also use distillate if gas supply is limited or unavailable.

The Electricity Trust of South Australia (ETSA) also has four gas turbine units with a total capacity of 246MW. These units use gas from the Cooper Basin gas fields in central Australia. More recently the Power & Water Authority in the Northern Territory installed five gas turbine units at Channel Island Power Station near Darwin, which use gas from the Palm Valley gas field near Alice Springs. Two of these gas turbines provide waste heat to drive a steam turbine in a combined cycle unit. This gives Channel Island a total capacity of 200MW.

The gas pipeline, which now runs from Palm Valley to Darwin, has also provided the opportunity to install new small scale gas turbines at Katherine, and to convert other diesel units from distillate to gas at various points along the pipeline route.

There is therefore ample precedent to support the concept of natural gas-fired electricity generation plants in Tasmania based on the recently discovered Yolla gas field in Bass Strait. It is understood that a pipeline from Yolla would most likely come ashore at Stanley, near the western end of the north coast of Tasmania.

A possible gas distribution structure would see a gas pipeline running along the north coast to Launceston and around to Bell Bay. For this study it has therefore been assumed that new gas-fired gas turbines would be installed at the existing HECT Bell Bay Power Station, which is in close proximity to the Comalco aluminium smelter. Gas-fired plant at this location would reduce transmission losses on the electricity grid, as well as providing a major gas user at the end of the pipeline.

This study has used gas turbine models based on the designs of the General Electric Co of the USA. GE gas turbines are made under licence by a number of manufacturers around the world. The gas turbine models selected are the GE Frame 6 of 34MW capacity and the GE Frame 9 of 116MW capacity.

Five Frame 6 models, manufactured by John Brown, have been installed at Channel Island near Darwin, and the State Electricity Commission of WA has eleven on order. Frame 9 machines have not yet been installed in Australia, but SECWA currently is negotiating to buy two. The Electricity Commission of NSW is considering gas turbine installations for the 1990's, and the Frame 9 is the preferred size of machine.

Budget prices have been sourced by NRG from two manufacturers to provide a basis for the installed cost estimate used in the economic evaluation. All costs used in the evaluation are nominally at December 1988 price levels. The manufacturers were MAN, representing Alsthom Atlantique, suppliers for the new SECWA machines and Marubeni representing Hitachi.

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In addition, estimates for erection costs and electrical equipment were obtained from Balfour Beatty, T A Mellen and Wilson Transformers. These companies were all involved in the Channel Island development. A breakdown of the cost estimates is shown in Table 4.1

TABLE 4.1 - GAS TURBINE CAPITAL COSTS.

Cost Component	Frame 6 34 MW $M	Frame 9 116 MW $M
Gas Turbine		
Supply	11.0	26.0
Erection	1.0	2.0
Sub Total	12.0	28.0
Electricals		
Generator Tx	0.8	2.1
Circuit Breaker	0.5	0.7
Prot. & Metering	0.2	0.3
Controls	1.0	1.5
Sub- Total	2.5	4.6
Civil Works		
Site Services	2.5	2.6
Foundations	0.4	0.6
Buildings	0.8	1.2
Sub-Total	3.7	4.4
Total Cost $M	**18.2**	**37.0**
$/kW	**535**	**320**

The above costs do not include for any part of the gas delivery system, so gas prices used in the study are at the point of delivery to the gas turbines. The costs generally are in accordance with the type of installation which the private sector would construct and do not include for any additional infrastructure facilities. Location at Bell Bay would allow the gas turbine station to share existing infrastructure.

Lead times for gas turbine units are typically three years with a two year construction period. An asset life of twenty years has been assumed to be on the conservative side, although longer a longer life could be achievable in practice.

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4.2 Gas Conversion of Bell Bay Power Station.

Conversion to gas firing of the existing 120 MW units at Bell Bay would be one way of providing natural gas usage in power generation. SECWA has previous experience in the conversion of 120 MW oil-fired units at their Kwinana Power Station south of Perth. The conversion to gas in that case resulted in a reduction of unit capacity from 120 MW to 108 MW.

However such a conversion would not add to the energy capability of the HECT system, and could reduce it. There would still be the need to provide additional energy capability to the system in 1997. For this reason the gas conversion of Bell Bay has not been considered as an option in the economic evaluations.

Once a gas supply was available, then conversion to gas would be a possible option. The cost of the conversion would in that case have to be justified against the reduction in oil costs with Bell Bay fulfilling its traditional role as thermal backup to the hydro system. This is a separate economic issue and outside the scope of this study.

4.3 Fingal Valley Coal-Fired Power Station.

The HECT is understood to have examined the feasibility of installing a 2x200 MW coal-fired thermal power station in the Fingal Valley south of Launceston. This station would use coal resources in the Fingal Valley, which would be mined by conventional underground techniques.

A feasibility study into this option was carried out for the HECT by consultants in 1983/84. However results of the study are not available.

Assumptions relating to this option are shown on the economic evaluation spreadsheets in Appendix A. The capital and O&M cost estimates were drawn from a generalised power station planning database, which has been developed from typical coal-fired power station costs in Queensland and NSW.

The cost of fuel has been assumed to be 200 c/GJ, which includes a small allowance for the fuel oil used in unit start-up This is equivalent to a coal price of approximately $45/tonne, which is consistent with underground coal prices in other States, taking into account the scale of the mining operation.

Project leadtimes can vary from seven to ten years, largely dependent on coal supply and environmental issues. The construction period is typically five to six years and an asset life of twenty five years has been assumed.

4.4 New Hydro Options.

HECT is known to have been examining a number of hydro electric schemes which could be brought into service after the Anthony Scheme. These options have been nominated by HECT as the Lower King, Que, Lake Augusta, King Racelines and potential redevelopment of old existing schemes at Lake Margaret and Tarraleah.

Nothing is known about the economics of these schemes outside of the HECT. However it is understood that they are relatively small scale schemes. Presumably their economic merit could not be better than Anthony, which is the latest scheme being developed. If the scale is small then the economics could be much worse than Anthony.

In the absence of any definitive information, the new hydro option used in this study has been based on a notional Anthony type scheme, with a single machine of 83 MW and an energy output of 41.5 MW Avg. (50% capacity factor). The capital cost has been based on the historical cost of Anthony to date, with estimates of future expenditure.

Interest during construction has been subtracted from the historic costs in order to give the actual construction cost year by year. An implicit price deflator has then been applied to bring the costs to an end 1988 basis. These cost analyses are shown in Table 4.2.

TABLE 4.2 - ANALYSIS OF ANTHONY CAPITAL COST.

Fiscal Year	Price Defl.	Total Cost $M	IDC $M	Constn Cost $M	Constn Cost Dec88 $M
1983/84	0.677	4.672	0.000	4.672	6.899
1984/85	0.730	15.870	0.692	15.178	20.788
1985/86	0.799	29.237	2.333	26.904	33.682
1986/87	0.865	34.031	5.389	28.642	33.104
1987/88	0.935	37.943	8.607	29.336	31.390
1988/89	1.000			25.000	25.000
1989/90	1.000			24.000	24.000
1990/91	1.000			23.000	23.000
1991/92	1.000			18.000	20.000
1992/93	1.000			15.000	15.000
1993/94	1.000			10.000	10.000
TOTAL $M				**219.732**	**242.862**
$/kW				**2,647**	**2,926**

The estimated future annual construction costs are at a lower level than costs to date because HECT has scaled down the intensity of construction to some extent, because the final commissioning date has been extended. The above cost estimates would include HECT's engineering costs and allowances for contingency. For the purposes of this study these costs are considered conservative.

A construction period of nine years has been assumed, consistent with past HECT experience. An asset life of fifty years has also been assumed although plant life could be less.

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4.5 High Voltage DC Cable from Victoria.

The possible installation of a high voltage DC undersea cable to link Tasmania with the mainland SECV system was examined in 1982 by the Zeidler Committee of Inquiry into a South Eastern Australia Electricity Grid. The reports of this Inquiry are in the public domain and have been used as the basis for the capital cost of the DC cable, escalated to December 88 price levels.

The capacity of the cable has been assumed to be 300 MW as per Zeidler and the estimated capital cost is $533M. One issue not clear with the cable option is the price that HECT would have to pay SECV for the power.

Reasonable energy quantities could be available on an off peak opportunity basis, and the price for this energy could be based on brown coal fuel costs alone with an allowance for transmission losses and variable operating and maintenance (O&M) costs. However the quantity of energy available at this price would be limited and probably only sufficient for the cable to operate at very low load factors.

For this reason it has been assumed that power purchases from SECV would be on a firm contract basis and would include a capital component for SECV power station capacity. The capital cost component used has been based on the reported cost of Units 3 and 4 of Loy Yang B Power Station.

The capacity factors used in the spreadsheet analysis refer to the cable capacity and in each case only sufficient SECV power station capacity is purchased to provide the energy flow corresponding to each capacity factor. This gives an increasing capital cost component with increasing cable capacity factors.

The fuel costs of the SECV purchases have likewise been based on Loy Yang B brown coal costs. As a contract purchase, fuel cost would not include any component of SECV gas fuel cost.

A project leadtime of five years has been assumed, along with a cable life of thirty years.

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5 ECONOMIC COMPARISON OF ALTERNATIVES.

5.1 Economic Screening.

The economic merit of the generation options considered has been determined by the annual sum approach. In this method capital costs are annualised as a function of asset life and discount rate. This gives a fixed cost which is then added to the yearly costs of O&M and fuel, which vary as a function of unit capacity factor.

This approach is commonly used to provide a fast ranking of generation options. It does not provide full economic information as no account is taken of the timing of capital expenditures. There are economic benefits in the deferment of capital expenditure until absolutely necessary. For example, construction of a high capital cost 200 MW thermal unit would result in over-investment for a time, as the unit size is much greater than Tasmanian electricity load growth would require. Smaller unit sizes are an advantage from this point of view.

The full economic picture can only be obtained with a detailed study over at least a fifteen year timeframe, in which simulations of system operation are carried out to determine total system operation costs, in addition to the capital expenditure streams. Such studies are complex and outside the scope of this project. Even so, the ranking method used for this project usually gives results consistent with more fully detailed economic evaluations.

Discount rate has a significant effect on the results of the evaluations. For this reason a range of discount rates from 4% to 10% real has been used.

Choice of discount rate in public sector economics is a matter of some argument between academics and authorities alike. The Federal Treasury supports the use of 10%, as this is taken to represent a market price for capital. In the electricity industry, Queensland and Victoria use 8%, while ECNSW uses 7%.

HECT has in the past used low discount rates (4% to 5%) primarily to assist in the justification of hydro schemes, which have long construction periods but long asset lives. However given the prominence of Australia's overseas debt at the present time, it is doubtful if HECT could currently sustain any argument for such low discount rates. In general, 8% could be considered as a preferred rate.

Figures 5.1 to 5.8 show, for discount rates of 10%, 8%, 6%, and 4%, annual costs ($/kW/a) and unit costs of supply (c/kWh) of the five generation options considered. While the thermal fuel options could operate over the range of capacity factors shown, the hydro option is constrained by water supply to an average operating point of 50% capacity factor.

Evaluation spreadsheet printouts at a discount rate of 8% for the five options are included in Appendix A as Tables A.1 to A.5. Unit costs of supply at a capacity factor of 50% for the options, at discount rates of 4% to 10%, are shown in Table 5.1.

TABLE 5.1 - GENERATION OPTIONS UNIT COST OF SUPPLY.

Generation Option.	Discount Rate 4% c/kWh	6% c/kWh	8% c/kWh	10% c/kWh
Frame 6 Gas Turbine	6.32	6.55	6.81	7.09
Frame 9 Gas Turbine	5.39	5.53	5.68	5.85
Coal-Fired Thermal	6.28	7.16	8.17	9.32
New Hydro	4.14	5.99	8.25	10.93
Bass Strait DC Cable	6.32	7.53	8.88	10.36

At 8% discount rate, the gas turbine options have lower costs than all the other options. At 6% the large Frame 9 gas turbines are the lowest cost option, with hydro now lower in cost than the smaller Frame 6 machines. At 4% the hydro option has become the lowest cost option. The coal and DC cable options are not economic at any discount rate.

The extreme sensitivity of the hydro option to discount rate is a function of interest during construction charges, which are very significant with a nine year construction period, and the fifty year asset life assumed for the hydro. The additional cost of IDC above the construction cost approaches 50% at the 10% discount rate.

These evaluations assumed a fixed gas price of $3.50/GJ for the gas turbine options. The next Sub-Section determines break even gas prices at which the gas turbine options have the same supply cost as the coal and hydro options.

FIG 5.1 - TASMANIAN GENERATION OPTIONS
ANNUAL COST OF SUPPLY
(10% Discount Rate)

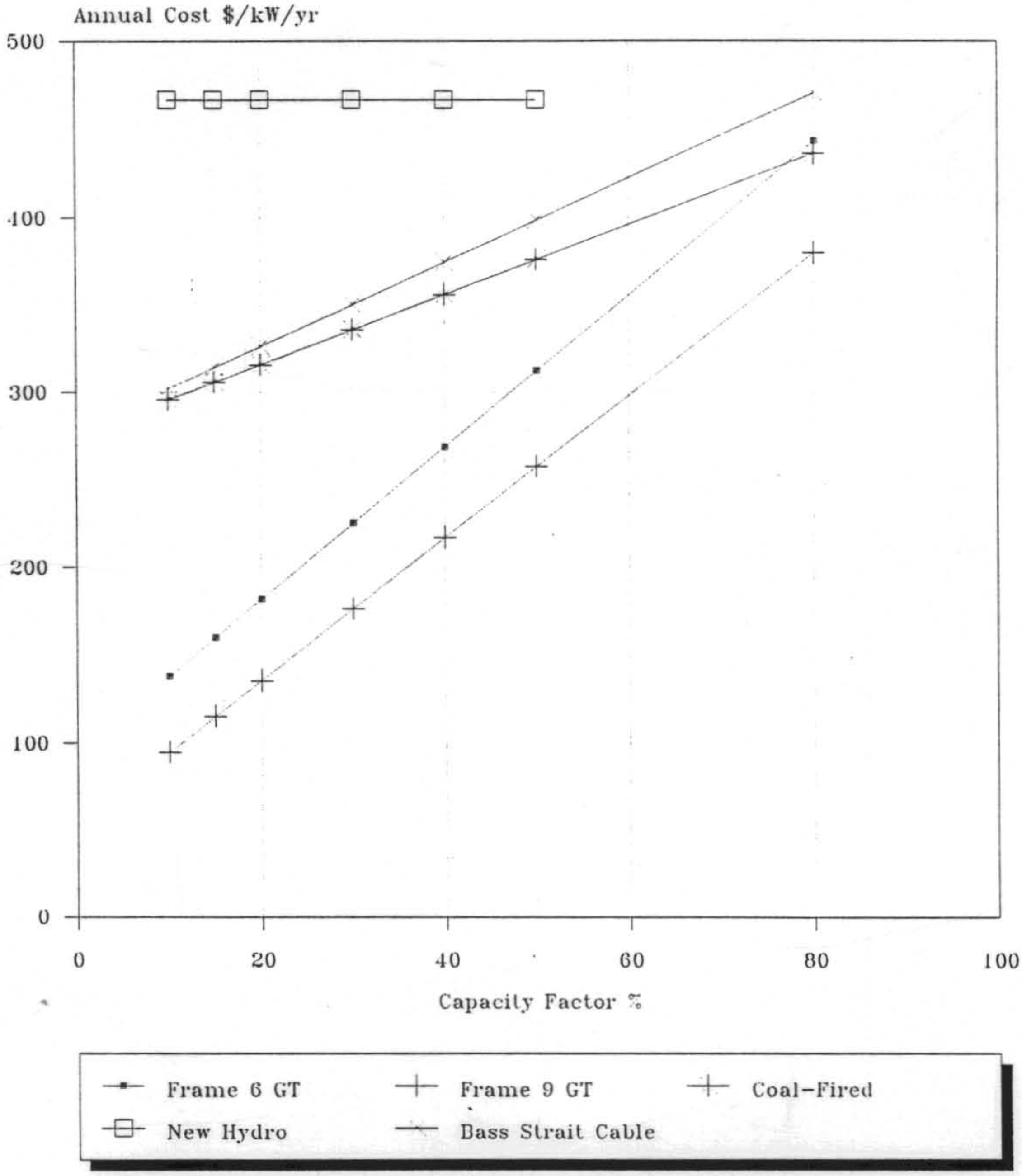
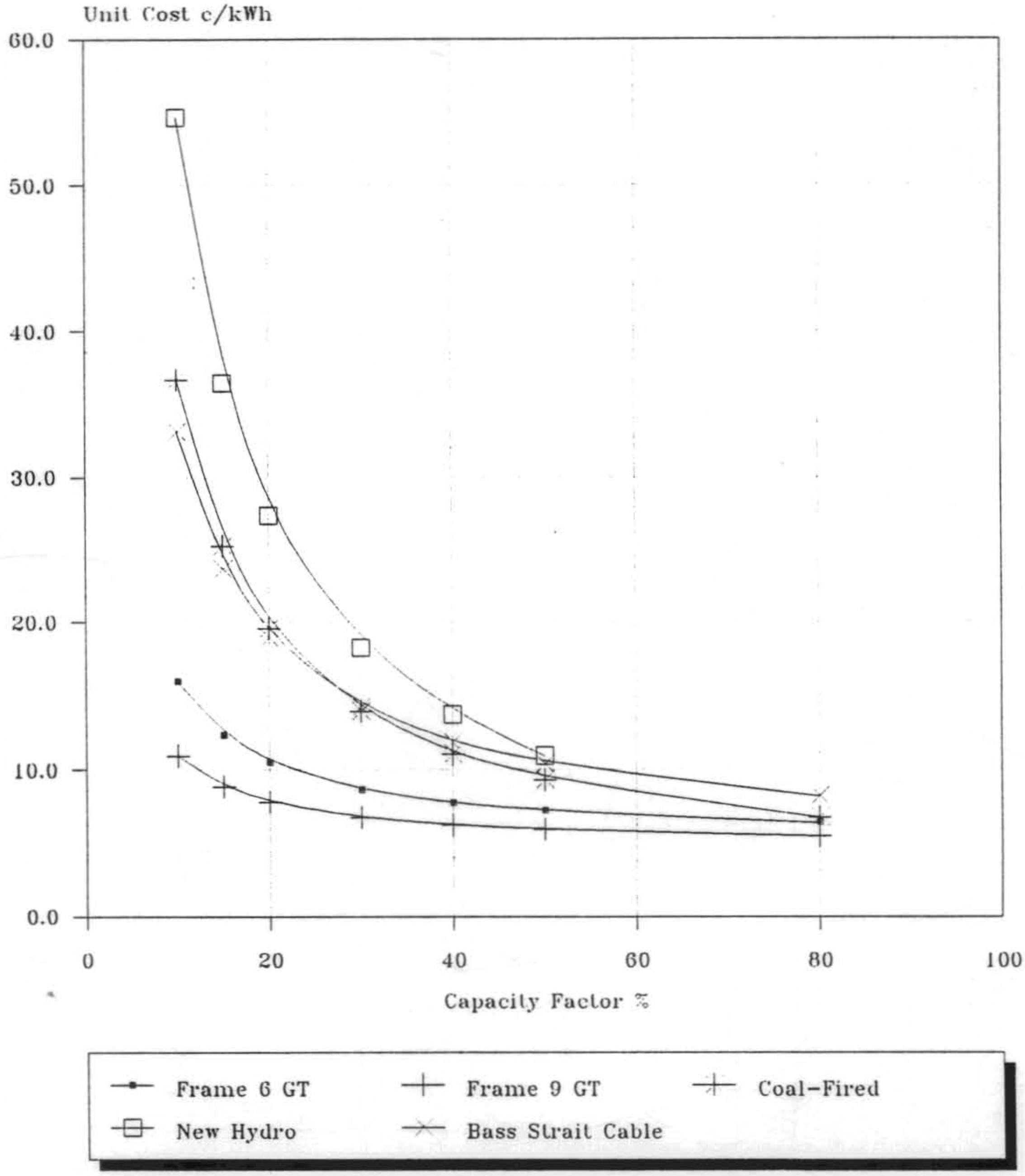


FIG 5.2 - TASMANIAN GENERATION OPTIONS
UNIT COST OF SUPPLY
(10% Discount Rate)



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5.2 Break Even Gas Prices.

In determining break even gas prices the Bass Strait DC cable was not considered further as this option appears rather less economic than the other options.

The break even gas price of the gas turbines against the coal-fired option is shown in Figure 5.9. The gas prices are shown against capacity factor and discount rates of 10% and 6% have been used.

Break even gas price values for the Frame 9 gas turbine are shown on the figure. A capacity factor of 60% would be a reasonable assumption for operation of the thermal plant options. At such a capacity factor the break even gas price is in the order of $4/GJ, increasing at lower capacity factors.

Against the hydro option a fixed capacity factor of 50% has been assumed. Break even gas prices of the gas turbines against the hydro option are shown in Figure 5.10 as a function of discount rate.

At a discount rate of 8% the break-even gas price is $4.50/GJ for the smaller Frame 6 gas turbine and $5.50/GJ for the larger Frame 9 machine.

In summary break-even gas prices are $4/GJ or higher for all options, with lower break-even prices only realised at lower discount rates and higher capacity factors than would normally be considered reasonable.

FIG 5.3 - TASMANIAN GENERATION OPTIONS
ANNUAL COST OF SUPPLY
(8% Discount Rate)

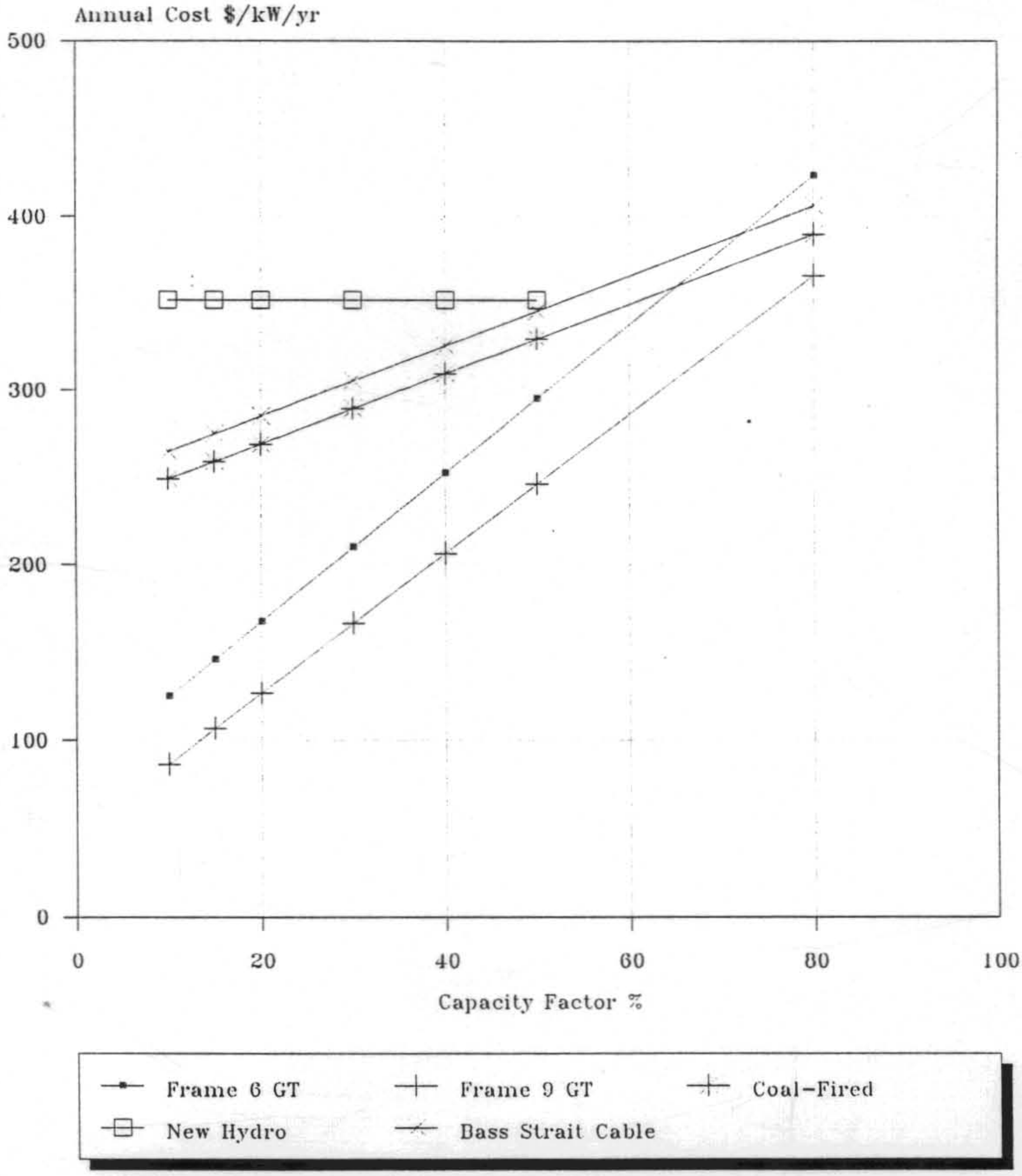

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FIG 5.4 - TASMANIAN GENERATION OPTIONS
UNIT COST OF SUPPLY
(8% Discount Rate)

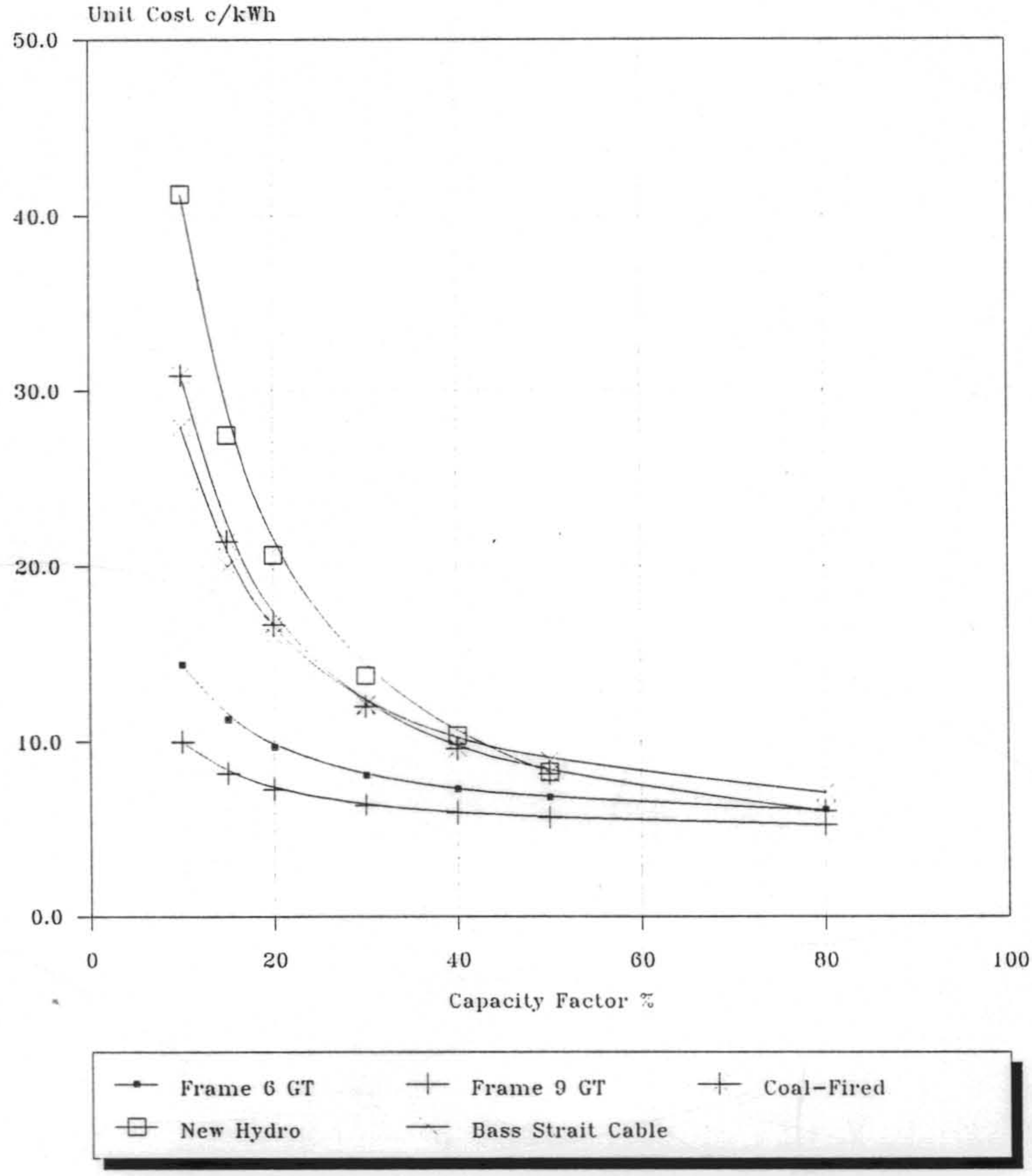

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FIG 5.5 - TASMANIAN GENERATION OPTIONS
ANNUAL COST OF SUPPLY
(6% Discount Rate)

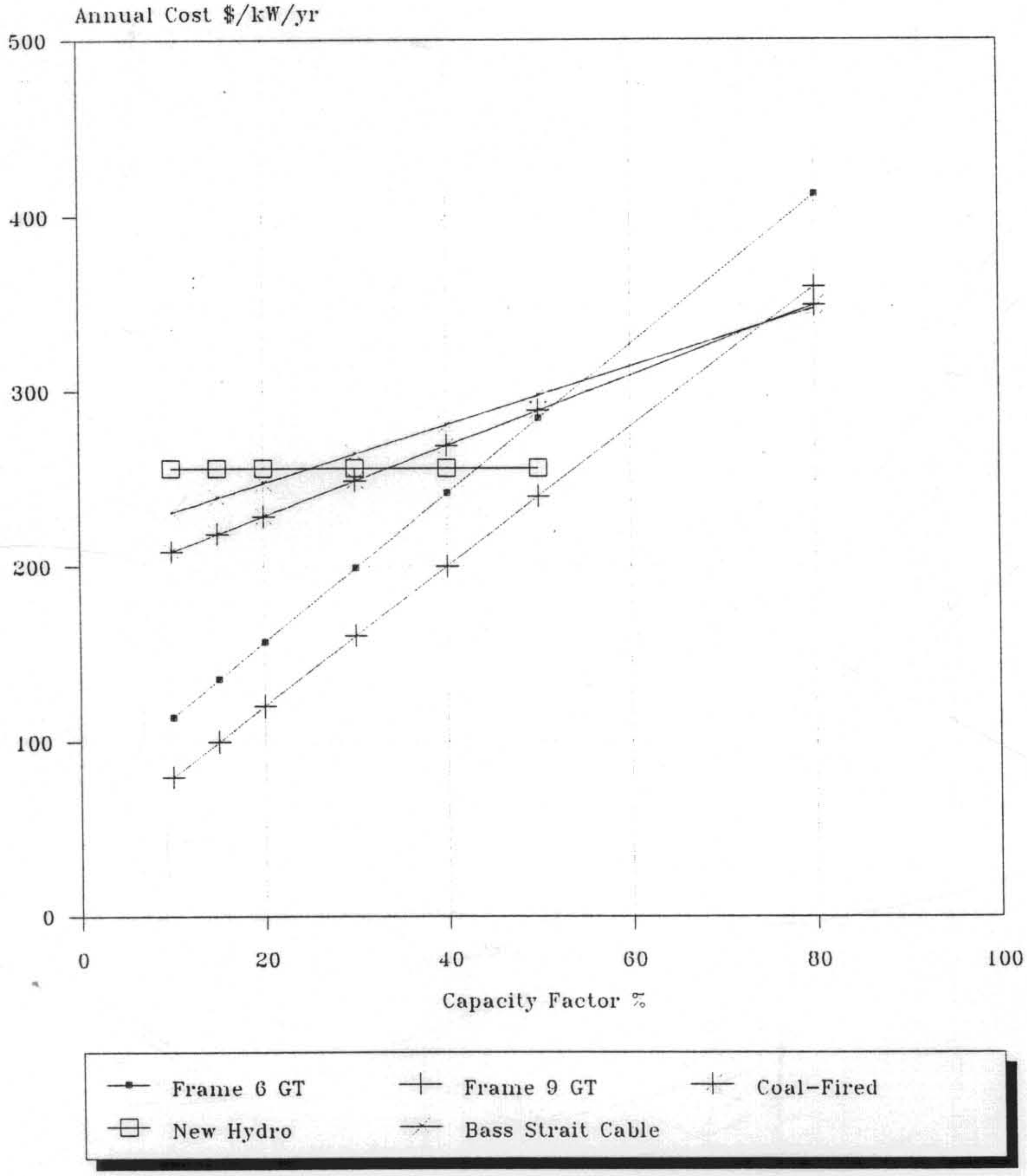

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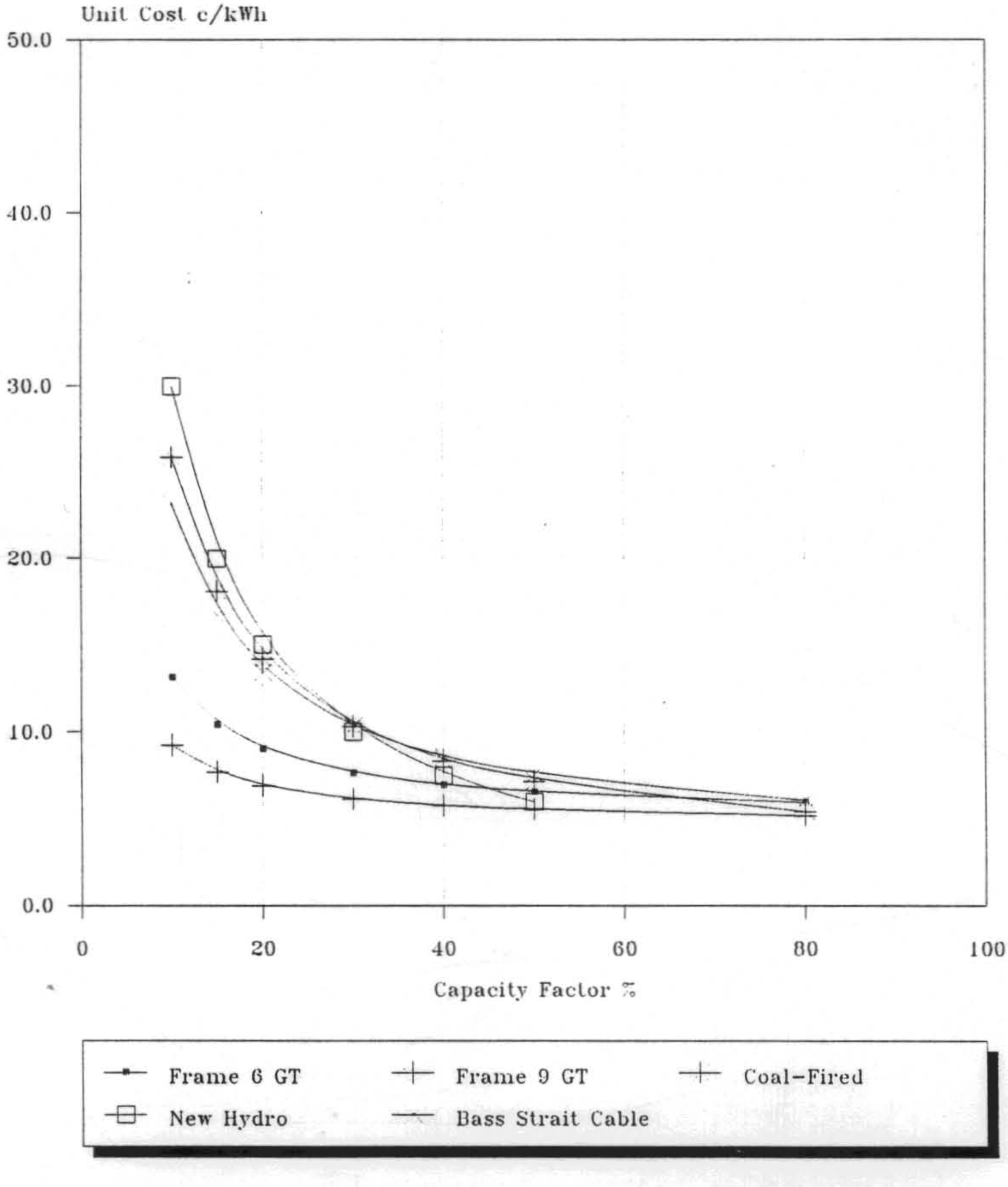
FIG 5.6 – TASMANIAN GENERATION OPTIONS
UNIT COST OF SUPPLY
(6% Discount Rate)



5 cm

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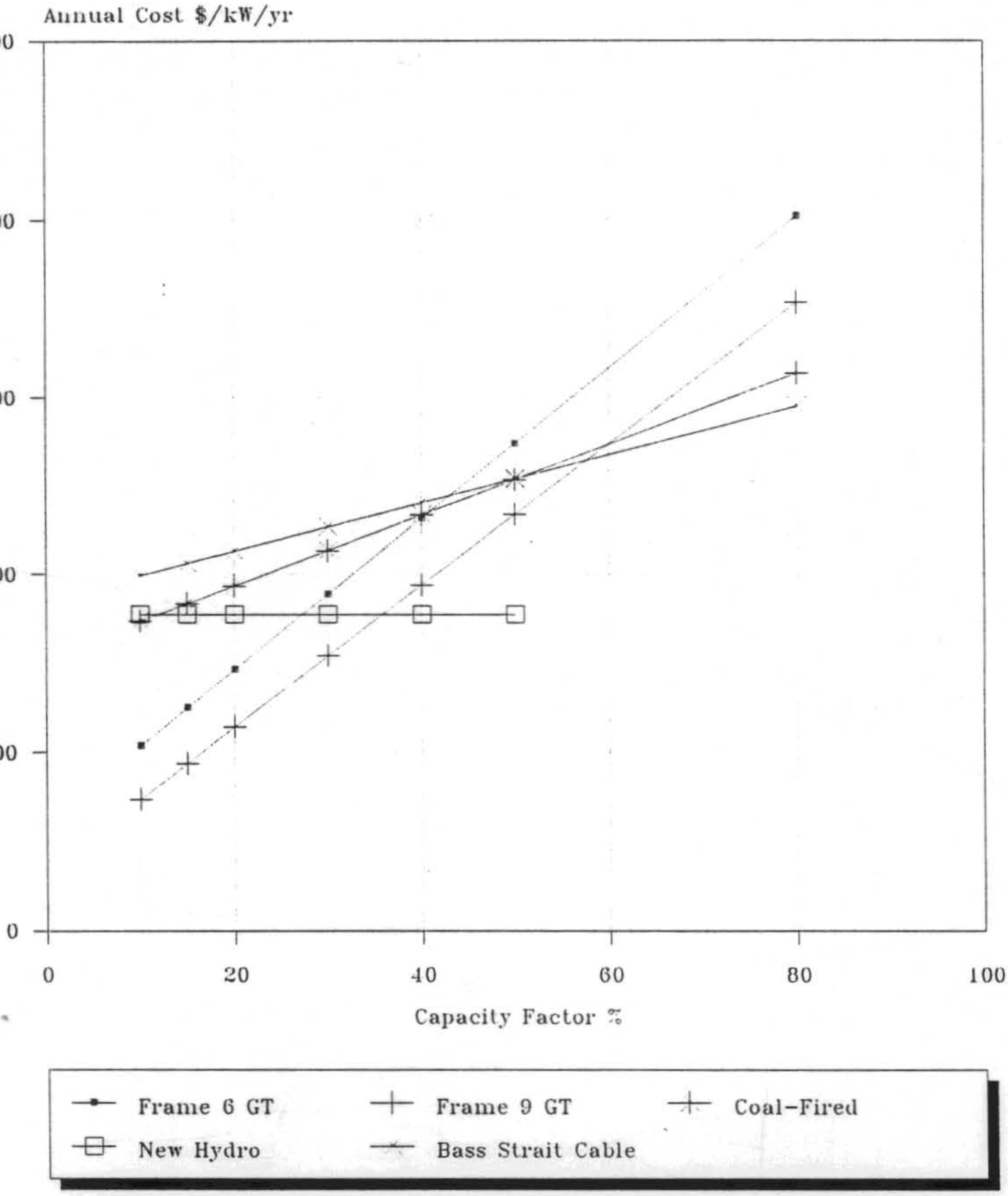
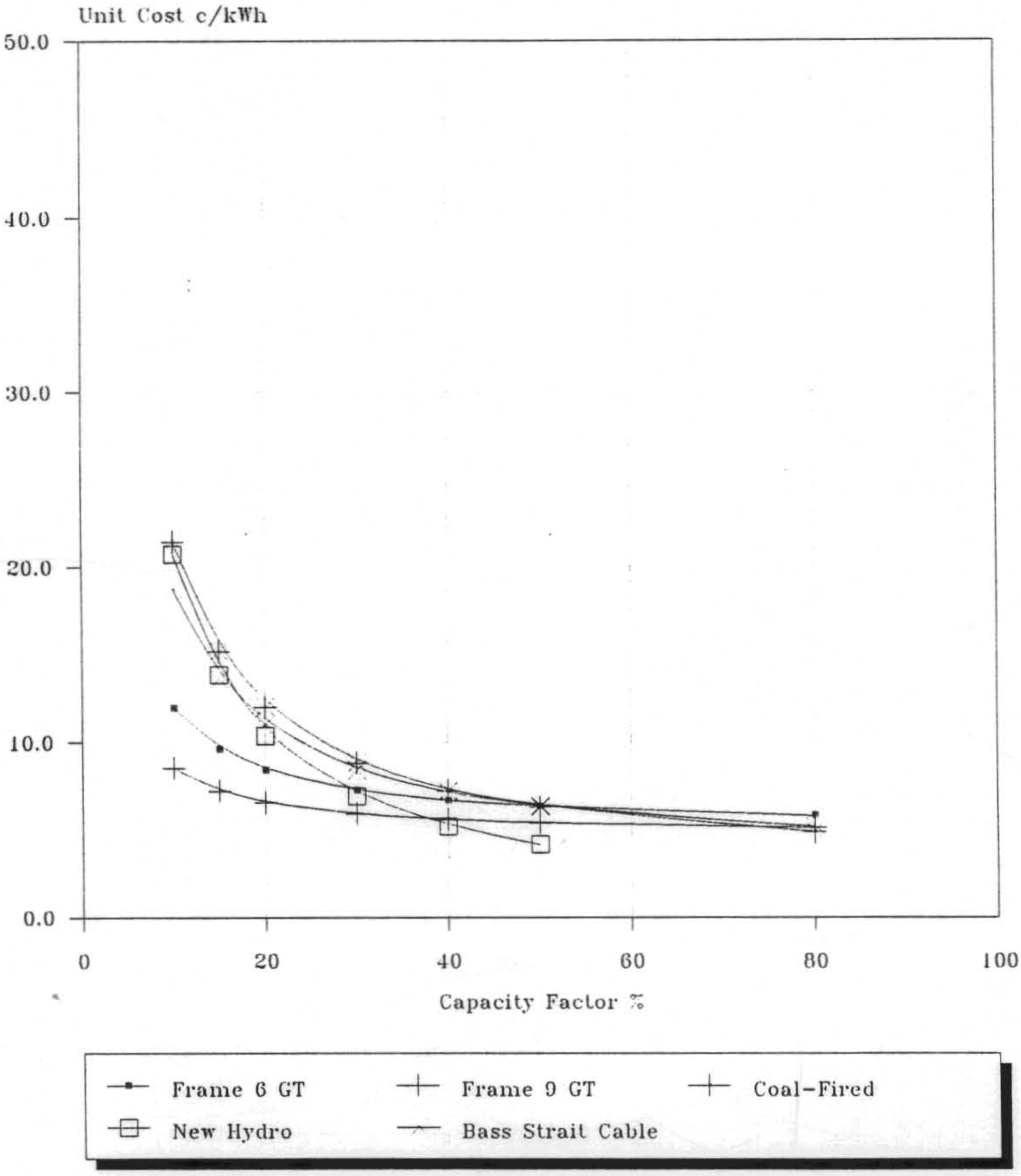
FIG 5.7 - TASMANIAN GENERATION OPTIONS

ANNUAL COST OF SUPPLY
(4% Discount Rate)



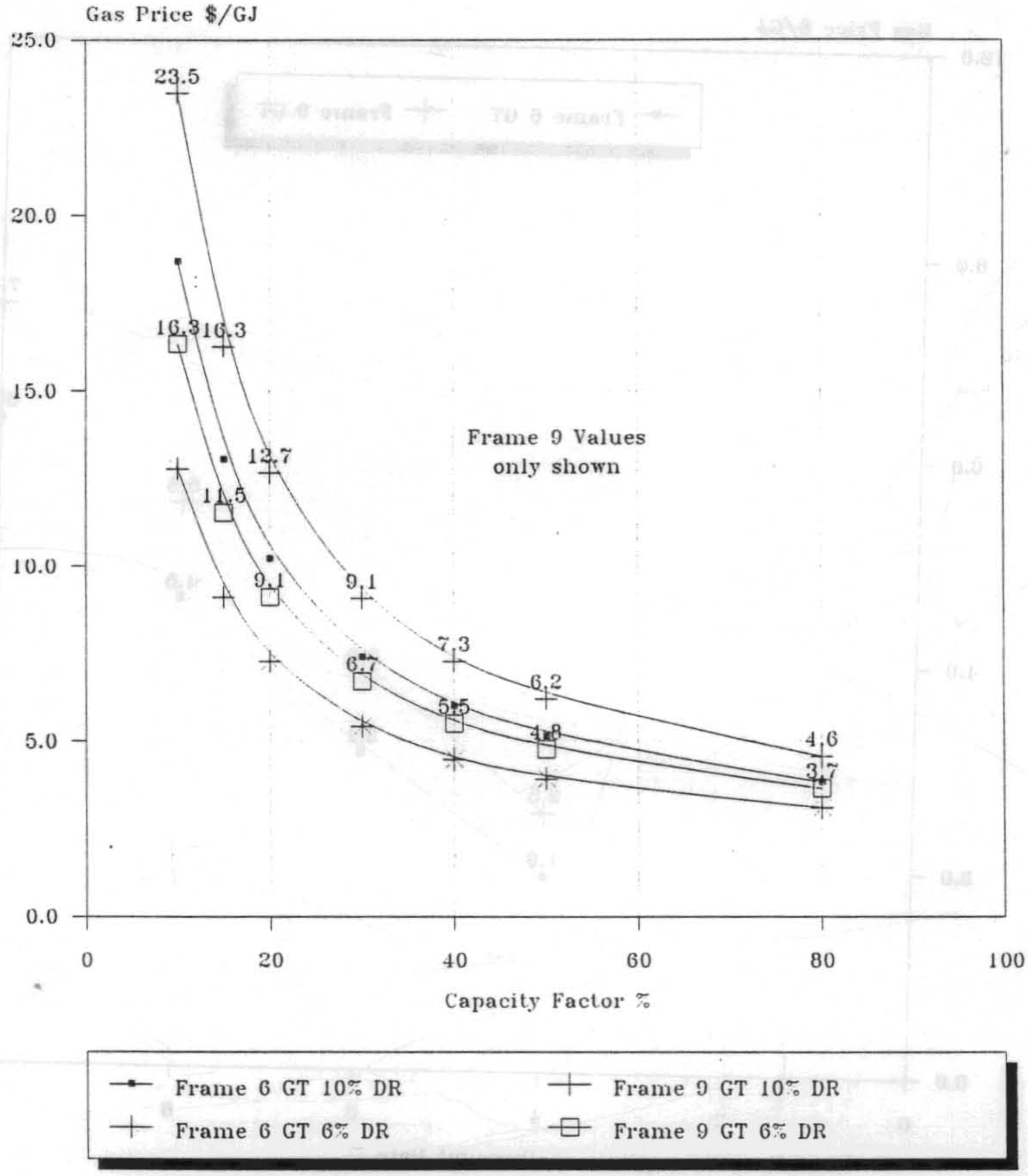
5 cm

FIG 5.8 – TASMANIAN GENERATION OPTIONS
UNIT COST OF SUPPLY
(4% Discount Rate)



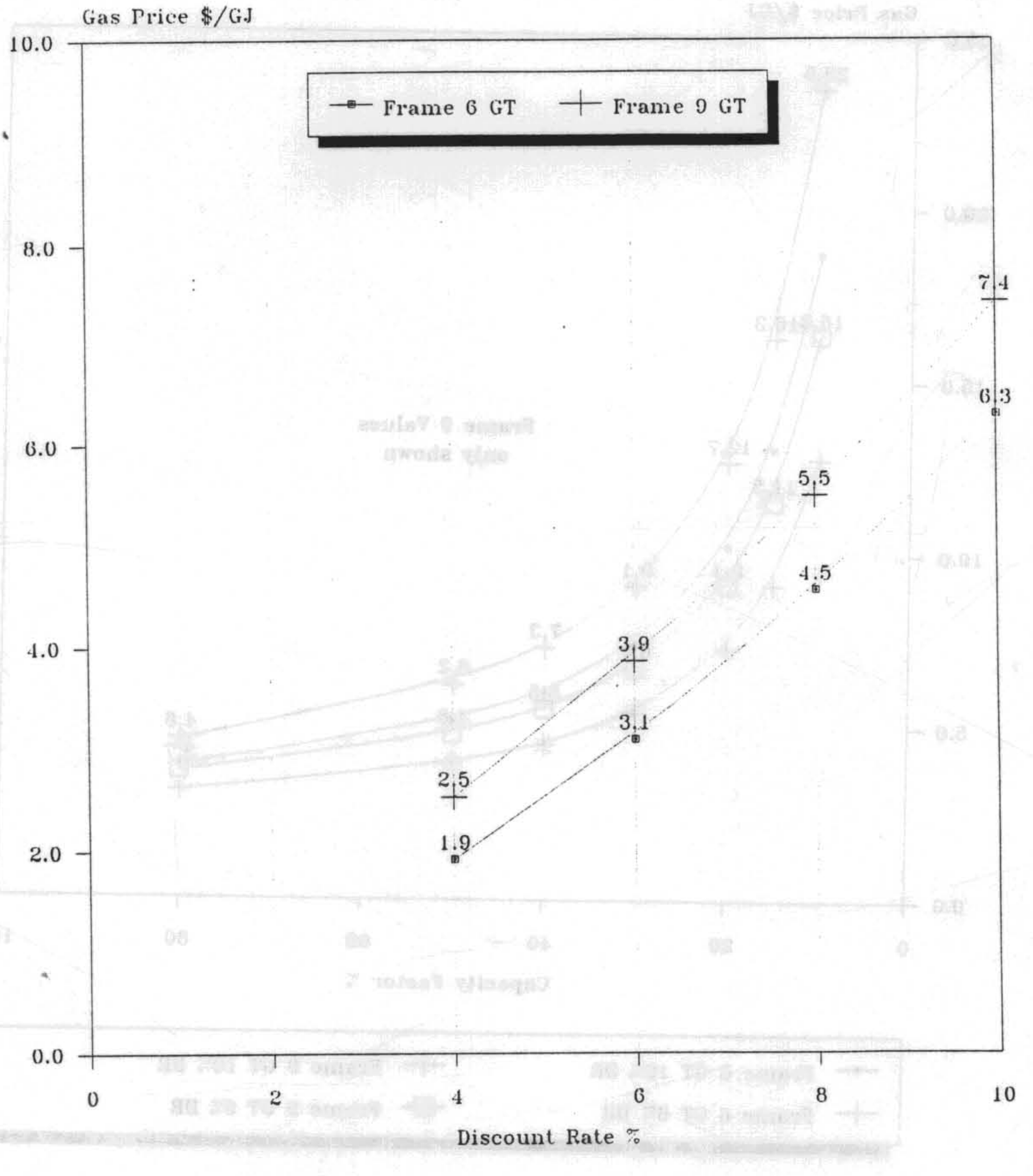
5 cm

FIG 5.9 - TASMANIAN GENERATION OPTIONS
BREAK EVEN GAS PRICE AGAINST COAL
(Various Discount Rates)



5 cm

FIG 5.10 – TASMANIAN GENERATION OPTIONS
BREAK EVEN GAS PRICE AGAINST HYDRO
(Hydro at 50% Capacity Factor)



5 cm

APPENDIX A

ECONOMIC ANALYSIS SPREADSHEETS.

Generation Options.

Frame 6 Gas Turbine (34 MW).
Frame 9 Gas Turbine (116 MW).
Coal-Fired Thermal (200 MW)
New Hydro Scheme (83 MW).
Bass Strait DC Cable (300 MW).

472416

TABLE A.1 – ECONOMIC PARAMETERS – FRAME 6 GAS TURBINE

DISCOUNT RATE 8.0%

UNIT TYPE FRAME 6 GT
FUEL TYPE NATURAL GAS

Annual Capacity Factor	**%**	**10**	**15**	**20**	**30**	**40**	**50**	**80**
Power Stn Unit Size	**MW**	**34**	**34**	**34**	**34**	**34**	**34**	**34**
Energy Generated	GWh	29.8	44.7	59.6	89.4	119.1	148.9	238.3
Auxiliary Cons.	%	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Energy Sent Out	GWh	29.6	44.5	59.3	88.9	118.5	148.2	237.1
Transmission Loss Rate	%	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Transmission Loss	GWh	0.1	0.2	0.3	0.4	0.6	0.7	1.2
Energy to Load Centre	**GWh**	**29.5**	**44.2**	**59.0**	**88.5**	**117.9**	**147.4**	**235.9**
Project Constn Period	Years	2	2	2	2	2	2	2
Interest During Constn	%	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Engineering Cost Factor	%	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Contingency Cost Factor	%	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Power Plant Life	Years	20	20	20	20	20	20	20
Infras. & Transm. Life	Years	30	30	30	30	30	30	30
Res. Plant Margin Factor		1.00	1.00	1.00	1.00	1.00	1.00	1.00
CAPITAL COSTS:								
Power Stn Cap Cost Base	$/kW	535	535	535	535	535	535	535
Power Stn Cap Cost Total	$/kW	679	679	679	679	679	679	679
Power Stn Capital Cost	**$M**							
Base		18.19	18.19	18.19	18.19	18.19	18.19	18.19
Site Allowances		0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		18.19	18.19	18.19	18.19	18.19	18.19	18.19
Contingency		1.82	1.82	1.82	1.82	1.82	1.82	1.82
Engineering		1.46	1.46	1.46	1.46	1.46	1.46	1.46
IDC		1.62	1.62	1.62	1.62	1.62	1.62	1.62
Total Cost	**$M**	**23.09**	**23.09**	**23.09**	**23.09**	**23.09**	**23.09**	**23.09**
Capital Charge Rate	%	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Other Capital Costs	**$M**							
Infrastructure		0.10	0.10	0.10	0.10	0.10	0.10	0.10
Water Supply		0.00	0.00	0.00	0.00	0.00	0.00	0.00
HV Transmission		0.20	0.20	0.20	0.20	0.20	0.20	0.20
Total Cost	**$M**	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Capital Charge Rate	%	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Annual Capital Charges	$M/a	2.38	2.38	2.38	2.38	2.38	2.38	2.38
Capital Unit Cost	**c/kWh**	8.07	5.38	4.03	2.69	2.02	1.61	1.01

TABLE A.1 – ECONOMIC PARAMETERS – FRAME 6 GAS TURBINE

DISCOUNT RATE 8.0%

UNIT TYPE FRAME 6 GT
FUEL TYPE NATURAL GAS

Annual Capacity Factor	%	10	15	20	30	40	50	80
OPERATING COSTS:								
O&M Fixed Cost Factor	$M/MW/a	0.012	0.012	0.012	0.012	0.012	0.012	0.012
O&M Vari. Cost Factor	$/MWh	1.1	1.1	1.1	1.1	1.1	1.1	1.1
O&M Costs – Fixed	$M/a	0.408	0.408	0.408	0.408	0.408	0.408	0.408
O&M Costs – Variable.	$M/a	0.033	0.049	0.066	0.098	0.131	0.164	0.262
– Water Supply	$M/a	0.000	0.000	0.000	0.000	0.000	0.000	0.000
– Total	$M/a	0.033	0.049	0.066	0.098	0.131	0.164	0.262
Total O&M Costs	**$M/a**	0.441	0.457	0.474	0.506	0.539	0.572	0.670
O&M Unit Cost	**c/kWh**	1.49	1.03	0.80	0.57	0.46	0.39	0.28
Fuel GHV (MJ/m3 for gas)	GJ/t	38.8	38.8	38.8	38.8	38.8	38.8	38.8
Unit Heat Rate Gen.	GJ/MWh	13.60	13.60	13.60	13.60	13.60	13.60	13.60
Unit Heat Rate SO	GJ/MWh	13.67	13.67	13.67	13.67	13.67	13.67	13.67
Fuel Cons. – Tonnage(Mm3)	kt/a	10.4	15.7	20.9	31.3	41.8	52.2	83.5
– Heat	TJ/a	405	608	810	1215	1620	2025	3240
Fuel Price Delivered	$/t	135.8	135.8	135.8	135.8	135.8	135.8	135.8
	c/GJ	350	350	350	350	350	350	350
Fuel Cost	**$M/a**	1.418	2.127	2.835	4.253	5.671	7.089	11.342
Fuel Unit Cost	**c/kWh**	4.81	4.81	4.81	4.81	4.81	4.81	4.81
TOTAL COSTS:								
Bulk Supply Cost	**$M/a**	4.237	4.962	5.687	7.138	8.588	10.039	14.390
Bulk Supply Unit Cost								
Capital	c/kWh	8.07	5.38	4.03	2.69	2.02	1.61	1.01
O&M	c/kWh	1.49	1.03	0.80	0.57	0.46	0.39	0.28
Fuel	c/kWh	4.81	4.81	4.81	4.81	4.81	4.81	4.81
Total	**c/kWh**	**14.37**	**11.22**	**9.64**	**8.07**	**7.28**	**6.81**	**6.10**
Unitised Cost Structure								
Fixed Cost	$/kW/a	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Variable Cost	$/kW/a	42.7	64.0	85.3	128.0	170.6	213.3	341.3
Total Cost	**$/kW/a**	**124.6**	**145.9**	**167.3**	**209.9**	**252.6**	**295.3**	**423.2**

(43) 10% better

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TABLE A.2 – ECONOMIC PARAMETERS – FRAME 9 GAS TURBINE

DISCOUNT RATE 8.0%

UNIT TYPE FRAME 9 GT
FUEL TYPE NATURAL GAS

Annual Capacity Factor	**%**	**10**	**15**	**20**	**30**	**40**	**50**	**80**
Power Stn Unit Size	**MW**	100	100	100	100	100	100	100
Energy Generated	GWh	87.6	131.4	175.2	262.8	350.4	438.0	700.8
Auxiliary Cons.	%	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Energy Sent Out	GWh	87.2	130.7	174.3	261.5	348.6	435.8	697.3
Transmission Loss Rate	%	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Transmission Loss	GWh	0.4	0.7	0.9	1.3	1.7	2.2	3.5
Energy to Load Centre	**GWh**	86.7	130.1	173.5	260.2	346.9	433.6	693.8
Project Constn Period	Years	2	2	2	2	2	2	2
Interest During Constn	%	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Engineering Cost Factor	%	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Contingency Cost Factor	%	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Power Plant Life	Years	20	20	20	20	20	20	20
Infras. & Transm. Life	Years	30	30	30	30	30	30	30
Res. Plant Margin Factor		1.00	1.00	1.00	1.00	1.00	1.00	1.00
CAPITAL COSTS:								
Power Stn Cap Cost Base	$/kW	320	320	320	320	320	320	320
Power Stn Cap Cost Total	$/kW	406	406	406	406	406	406	406
Power Stn Capital Cost	**$M**							
Base		32.00	32.00	32.00	32.00	32.00	32.00	32.00
Site Allowances		0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		32.00	32.00	32.00	32.00	32.00	32.00	32.00
Contingency		3.20	3.20	3.20	3.20	3.20	3.20	3.20
Engineering		2.56	2.56	2.56	2.56	2.56	2.56	2.56
IDC		2.86	2.86	2.86	2.86	2.86	2.86	2.86
Total Cost	**$M**	40.62	40.62	40.62	40.62	40.62	40.62	40.62
Capital Charge Rate	%	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Other Capital Costs	**$M**							
Infrastructure		0.10	0.10	0.10	0.10	0.10	0.10	0.10
Water Supply		0.00	0.00	0.00	0.00	0.00	0.00	0.00
HV Transmission		0.20	0.20	0.20	0.20	0.20	0.20	0.20
Total Cost	**$M**	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Capital Charge Rate	%	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Annual Capital Charges	$M/a	4.16	4.16	4.16	4.16	4.16	4.16	4.16
Capital Unit Cost	**c/kWh**	4.80	3.20	2.40	1.60	1.20	0.96	0.60

TABLE A.2 – ECONOMIC PARAMETERS – FRAME 9 GAS TURBINE

DISCOUNT RATE 8.0%

UNIT TYPE **FRAME 9 GT**
FUEL TYPE **NATURAL GAS**

Annual Capacity Factor	**%**	**10**	**15**	**20**	**30**	**40**	**50**	**80**
OPERATING COSTS:								
O&M Fixed Cost Factor	$M/MW/a	0.005	0.005	0.005	0.005	0.005	0.005	0.005
O&M Vari. Cost Factor	$/MWh	0.8	0.8	0.8	0.8	0.8	0.8	0.8
O&M Costs – Fixed	$M/a	0.500	0.500	0.500	0.500	0.500	0.500	0.500
O&M Costs – Variable.	$M/a	0.070	0.105	0.140	0.210	0.280	0.350	0.561
– Water Supply	$M/a	0.000	0.000	0.000	0.000	0.000	0.000	0.000
– Total	$M/a	0.070	0.105	0.140	0.210	0.280	0.350	0.561
Total O&M Costs	**$M/a**	0.570	0.605	0.640	0.710	0.780	0.850	1.061
O&M Unit Cost	**c/kWh**	0.66	0.47	0.37	0.27	0.22	0.20	0.15
Fuel GHV (MJ/m3 for gas)	GJ/t	38.8	38.0	38.0	38.0	38.0	38.0	38.0
Unit Heat Rate Gen.	GJ/MWh	12.80	12.80	12.80	12.80	12.80	12.80	12.80
Unit Heat Rate SO	GJ/MWh	12.86	12.86	12.86	12.86	12.86	12.86	12.86
Fuel Cons. – Tonnage(Mm3)	kt/a	28.9	44.3	59.0	88.5	118.0	147.5	236.1
– Heat	TJ/a	1121	1682	2243	3364	4485	5606	8970
Fuel Price Delivered	$/t	135.8	133.0	133.0	133.0	133.0	133.0	133.0
	c/GJ	350	350	350	350	350	350	350
Fuel Cost	**$M/a**	3.924	5.887	7.849	11.773	15.698	19.622	31.396
Fuel Unit Cost	**c/kWh**	4.53	4.53	4.53	4.53	4.53	4.53	4.53
TOTAL COSTS:								
Bulk Supply Cost	**$M/a**	8.658	10.656	12.653	16.647	20.642	24.636	36.620
Bulk Supply Unit Cost								
Capital	c/kWh	4.80	3.20	2.40	1.60	1.20	0.96	0.60
O&M	c/kWh	0.66	0.47	0.37	0.27	0.22	0.20	0.15
Fuel	c/kWh	4.53	4.53	4.53	4.53	4.53	4.53	4.53
Total	**c/kWh**	**9.98**	**8.19**	**7.29**	**6.40**	**5.95**	**5.68**	**5.28**
Unitised Cost Structure								
Fixed Cost	$/kW/a	46.6	46.6	46.6	46.6	46.6	46.6	46.6
Variable Cost	$/kW/a	39.9	59.9	79.9	119.8	159.8	199.7	319.6
Total Cost	**$/kW/a**	**86.6**	**106.6**	**126.5**	**166.5**	**206.4**	**246.4**	**366.2**

TABLE A.3 - ECONOMIC PARAMETERS - COAL-FIRED THERMAL

DISCOUNT RATE 8.0%

UNIT TYPE THERMAL POWER STATION
FUEL TYPE COAL

Annual Capacity Factor	**%**	**10**	**15**	**20**	**30**	**40**	**50**	**80**
Power Stn Unit Size	**MW**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
Energy Generated	GWh	175.2	262.8	350.4	525.6	700.8	876.0	1401.6
Auxiliary Cons.	%	6	6	6	6	6	6	6
Energy Sent Out	GWh	164.7	247.0	329.4	494.1	658.8	823.4	1317.5
Transmission Loss Rate	%	2	2	2	2	2	2	2
Transmission Loss	GWh	3.3	4.9	6.6	9.9	13.2	16.5	26.4
Energy to Load Centre	**GWh**	**161.4**	**242.1**	**322.8**	**484.2**	**645.6**	**807.0**	**1291.2**
Project Constn Period	Years	5	5	5	5	5	5	5
Interest During Constn	%	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Engineering Cost Factor	%	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Contingency Cost Factor	%	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Power Plant Life	Years	25	25	25	25	25	25	25
Infras. & Transm. Life	Years	30	30	30	30	30	30	30
Res. Plant Margin Factor		1.05	1.05	1.05	1.05	1.05	1.05	1.05
CAPITAL COSTS:								
Power Stn Cap Cost Base	$/kW	1400	1400	1400	1400	1400	1400	1400
Power Stn Cap Cost Total	$/kW	2049	2049	2049	2049	2049	2049	2049
Power Stn Capital Cost	**$M**							
Base		280.00	280.00	280.00	280.00	280.00	280.00	280.00
Site Allowances		0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		280.00	280.00	280.00	280.00	280.00	280.00	280.00
Contingency		28.00	28.00	28.00	28.00	28.00	28.00	28.00
Engineering		33.60	33.60	33.60	33.60	33.60	33.60	33.60
IDC		68.29	68.29	68.29	68.29	68.29	68.29	68.29
Total Cost	**$M**	**409.89**	**409.89**	**409.89**	**409.89**	**409.89**	**409.89**	**409.89**
Capital Charge Rate	%	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Other Capital Costs	**$M**							
Infrastructure		10.00	10.00	10.00	10.00	10.00	10.00	10.00
Water Supply		10.00	10.00	10.00	10.00	10.00	10.00	10.00
HV Transmission		5.00	5.00	5.00	5.00	5.00	5.00	5.00
Total Cost	**$M**	25.00	25.00	25.00	25.00	25.00	25.00	25.00
Capital Charge Rate	%	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Annual Capital Charges	$M/a	40.62	40.62	40.62	40.62	40.62	40.62	40.62
Capital Unit Cost	**c/kWh**	25.17	16.78	12.58	8.39	6.29	5.03	3.15

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TABLE A.3 – ECONOMIC PARAMETERS – COAL–FIRED THERMAL

DISCOUNT RATE 8.0%

UNIT TYPE THERMAL POWER STATION
FUEL TYPE COAL

Annual Capacity Factor	**%**	**10**	**15**	**20**	**30**	**40**	**50**	**80**
OPERATING COSTS:								
O&M Fixed Cost Factor	$M/MW/a	0.026	0.026	0.026	0.026	0.026	0.026	0.026
O&M Vari. Cost Factor	$/MWh	0.8	0.8	0.8	0.8	0.8	0.8	0.8
O&M Costs – Fixed	$M/a	5.200	5.200	5.200	5.200	5.200	5.200	5.200
O&M Costs – Variable.	$M/a	0.140	0.210	0.280	0.420	0.561	0.701	1.121
– Water Supply	$M/a	0.200	0.300	0.400	0.600	0.800	1.000	1.600
– Total	$M/a	0.340	0.510	0.680	1.020	1.361	1.701	2.721
Total O&M Costs	**$M/a**	5.540	5.710	5.880	6.220	6.561	6.901	7.921
O&M Unit Cost	**c/kWh**	3.43	2.36	1.82	1.28	1.02	0.86	0.61
Fuel GHV (MJ/m3 for gas)	GJ/t	23.0	23.0	23.0	23.0	23.0	23.0	23.0
Unit Heat Rate Gen.	GJ/MWh	10.50	10.50	10.50	10.50	10.50	10.50	10.50
Unit Heat Rate SO	GJ/MWh	11.17	11.17	11.17	11.17	11.17	11.17	11.17
Fuel Cons. – Tonnage(Mm3)	kt/a	80.0	120.0	160.0	239.9	319.9	399.9	639.9
– Heat	TJ/a	1840	2759	3679	5519	7358	9198	14717
Fuel Price Delivered	$/t	46.0	46.0	46.0	46.0	46.0	46.0	46.0
	c/GJ	200	200	200	200	200	200	200
Fuel Cost	**$M/a**	3.679	5.519	7.358	11.038	14.717	18.396	29.434
Fuel Unit Cost	**c/kWh**	2.28	2.28	2.28	2.28	2.28	2.28	2.28
TOTAL COSTS:								
Bulk Supply Cost	**$M/a**	49.838	51.848	53.857	57.877	61.896	65.915	77.973
Bulk Supply Unit Cost								
Capital	c/kWh	25.17	16.78	12.58	8.39	6.29	5.03	3.15
O&M	c/kWh	3.43	2.36	1.82	1.28	1.02	0.86	0.61
Fuel	c/kWh	2.28	2.28	2.28	2.28	2.28	2.28	2.28
Total	**c/kWh**	**30.88**	**21.42**	**16.68**	**11.95**	**9.59**	**8.17**	**6.04**
Unitised Cost Structure								
Fixed Cost	$/kW/a	229.1	229.1	229.1	229.1	229.1	229.1	229.1
Variable Cost	$/kW/a	20.1	30.1	40.2	60.3	80.4	100.5	160.8
Total Cost	**$/kW/a**	**249.2**	**259.2**	**269.3**	**289.4**	**309.5**	**329.6**	**389.9**

TABLE A.4 – ECONOMIC PARAMETERS – NEW HYDRO

DISCOUNT RATE 8.0%

UNIT TYPE				HYDRO POWER STATION			
FUEL TYPE				WATER			
Annual Capacity Factor	**%**	**10**	**15**	**20**	**30**	**40**	**50**
Power Stn Unit Size	**MW**	83	83	83	83	83	83
Energy Generated	GWh	72.7	109.1	145.4	218.1	290.8	363.5
Auxiliary Cons.	%	0.5	0.5	0.5	0.5	0.5	0.5
Energy Sent Out	GWh	72.3	108.5	144.7	217.0	289.4	361.7
Transmission Loss Rate	%	2	2	2	2	2	2
Transmission Loss	GWh	1.4	2.2	2.9	4.3	5.8	7.2
Energy to Load Centre	**GWh**	**70.9**	**106.3**	**141.8**	**212.7**	**283.6**	**354.5**
Project Constn Period	Years	9	9	9	9	9	9
Interest During Constn	%	38.8	38.8	38.8	38.8	38.8	38.8
Engineering Cost Factor	%	12.0	12.0	12.0	12.0	12.0	12.0
Contingency Cost Factor	%	10.0	10.0	10.0	10.0	10.0	10.0
Power Plant Life	Years	50	50	50	50	50	50
Infras. & Transm. Life	Years	30	30	30	30	30	30
Res. Plant Margin Factor		1.00	1.00	1.00	1.00	1.00	1.00
CAPITAL COSTS:							
Power Stn Cap Cost Base	$/kW	2400	2400	2400	2400	2400	2400
Power Stn Cap Cost Total	$/kW	4063	4063	4063	4063	4063	4063
Power Stn Capital Cost	**$M**						
Base		199.20	199.20	199.20	199.20	199.20	199.20
Site Allowances		0.00	0.00	0.00	0.00	0.00	0.00
Sub–Total		199.20	199.20	199.20	199.20	199.20	199.20
Contingency		19.92	19.92	19.92	19.92	19.92	19.92
Engineering		23.90	23.90	23.90	23.90	23.90	23.90
IDC		94.18	94.18	94.18	94.18	94.18	94.18
Total Cost	**$M**	337.21	337.21	337.21	337.21	337.21	337.21
Capital Charge Rate	%	8.2	8.2	8.2	8.2	8.2	8.2
Other Capital Costs	**$M**						
Infrastructure		5.00	5.00	5.00	5.00	5.00	5.00
Water Supply		0.00	0.00	0.00	0.00	0.00	0.00
HV Transmission		5.00	5.00	5.00	5.00	5.00	5.00
Total Cost	**$M**	10.00	10.00	10.00	10.00	10.00	10.00
Capital Charge Rate	%	8.9	8.9	8.9	8.9	8.9	8.9
Annual Capital Charges	$M/a	28.45	28.45	28.45	28.45	28.45	28.45
Capital Unit Cost	c/kWh	40.13	26.75	20.07	13.38	10.03	8.03

TABLE A.4 – ECONOMIC PARAMETERS – NEW HYDRO

DISCOUNT RATE 8.0%

UNIT TYPE — HYDRO POWER STATION

FUEL TYPE — WATER

Annual Capacity Factor	%	10	15	20	30	40	50
OPERATING COSTS:							
O&M Fixed Cost Factor	$M/MW/a	0.009	0.009	0.009	0.009	0.009	0.009
O&M Vari. Cost Factor	$/MWh	0	0	0	0	0	0
O&M Costs – Fixed	$M/a	0.780	0.780	0.780	0.780	0.780	0.780
O&M Costs – Variable.	$M/a	0.000	0.000	0.000	0.000	0.000	0.000
– Water Supply	$M/a	0.000	0.000	0.000	0.000	0.000	0.000
– Total	$M/a	0.000	0.000	0.000	0.000	0.000	0.000
Total O&M Costs	**$M/a**	0.780	0.780	0.780	0.780	0.780	0.780
O&M Unit Cost	**c/kWh**	1.10	0.73	0.55	0.37	0.28	0.22
Fuel GHV (MJ/m3 for gas)	GJ/t	0.0	0.0	0.0	0.0	0.0	0.0
Unit Heat Rate Gen.	GJ/MWh	10.50	10.50	10.50	10.50	10.50	10.50
Unit Heat Rate SO	GJ/MWh	10.55	10.55	10.55	10.55	10.55	10.55
Fuel Cons. – Tonnage(Mm3)	kt/a	ERR	ERR	ERR	ERR	ERR	ERR
– Heat	TJ/a	763	1145	1527	2290	3054	3817
Fuel Price Delivered	$/t	0.0	0.0	0.0	0.0	0.0	0.0
	c/GJ	0	0	0	0	0	0
Fuel Cost	**$M/a**	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Unit Cost	**c/kWh**	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL COSTS:							
Bulk Supply Cost	**$M/a**	29.233	29.233	29.233	29.233	29.233	29.233
Bulk Supply Unit Cost							
Capital	c/kWh	40.13	26.75	20.07	13.38	10.03	8.03
O&M	c/kWh	1.10	0.73	0.55	0.37	0.28	0.22
Fuel	c/kWh	0.00	0.00	0.00	0.00	0.00	0.00
Total	**c/kWh**	**41.23**	**27.49**	**20.62**	**13.74**	**10.31**	**8.25**
Unitised Cost Structure							
Fixed Cost	$/kW/a	352.2	352.2	352.2	352.2	352.2	352.2
Variable Cost	$/kW/a	0.0	0.0	0.0	0.0	0.0	0.0
Total Cost	**$/kW/a**	**352.2**	**352.2**	**352.2**	**352.2**	**352.2**	**352.2**

TABLE A.5 - ECONOMIC PARAMETERS - BASS STRAIT DC CABLE

DISCOUNT RATE 8.0%

UNIT TYPE BASS STRAIT DC CABLE
FUEL TYPE 300 MW

Annual Capacity Factor	%	10	15	20	30	40	50	80
Power Stn Unit Size	**MW**	**37.5**	**56.3**	**75.0**	**112.5**	**150.0**	**187.5**	**300.0**
Energy Generated	GWh	262.8	394.2	525.6	788.4	1051.2	1314.0	2102.4
Auxiliary Cons.	%	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Energy Sent Out	GWh	243.9	365.8	487.8	731.6	975.5	1219.4	1951.0
Transmission Loss Rate	%	12	12	12	12	12	12	12
Transmission Loss	GWh	29.3	43.9	58.5	87.8	117.1	146.3	234.1
Energy to Load Centre	**GWh**	**214.6**	**321.9**	**429.2**	**643.8**	**858.5**	**1073.1**	**1716.9**
Project Constn Period	Years	5	5	5	5	5	5	5
Interest During Constn	%	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Engineering Cost Factor	%	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Contingency Cost Factor	%	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Power Plant Life	Years	25	25	25	25	25	25	25
Infras. & Transm. Life	Years	30	30	30	30	30	30	30
Res. Plant Margin Factor		1.00	1.00	1.00	1.00	1.00	1.00	1.00
CAPITAL COSTS:								
Power Stn Cap Cost Base	$/kW	1000	1000	1000	1000	1000	1000	1000
Power Stn Cap Cost Total	$/kW	1464	1464	1464	1464	1464	1464	1464
Power Stn Capital Cost	**$M**							
Base		37.50	56.25	75.00	112.50	150.00	187.50	300.00
Site Allowances		0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		37.50	56.25	75.00	112.50	150.00	187.50	300.00
Contingency		3.75	5.63	7.50	11.25	15.00	18.75	30.00
Engineering		4.50	6.75	9.00	13.50	18.00	22.50	36.00
IDC		9.15	13.72	18.29	27.44	36.58	45.73	73.17
Total Cost	**$M**	**54.90**	**82.34**	**109.79**	**164.69**	**219.58**	**274.48**	**439.17**
Capital Charge Rate	%	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Other Capital Costs	**$M**							
Infrastructure		5.00	5.00	5.00	5.00	5.00	5.00	5.00
Water Supply		0.00	0.00	0.00	0.00	0.00	0.00	0.00
HV Transmission		570.00	570.00	570.00	570.00	570.00	570.00	570.00
Total Cost	**$M**	575.00	575.00	575.00	575.00	575.00	575.00	575.00
Capital Charge Rate	%	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Annual Capital Charges	$M/a	56.22	58.79	61.36	66.50	71.65	76.79	92.22
Capital Unit Cost	**c/kWh**	26.20	18.26	14.30	10.33	8.35	7.16	5.37

TABLE A.5 – ECONOMIC PARAMETERS – BASS STRAIT DC CABLE

DISCOUNT RATE 8.0%

UNIT TYPE **BASS STRAIT DC CABLE**
FUEL TYPE **300 MW**

Annual Capacity Factor	**%**	**10**	**15**	**20**	**30**	**40**	**50**	**80**
OPERATING COSTS:								
O&M Fixed Cost Factor	$M/MW/a	0.024	0.024	0.024	0.024	0.024	0.024	0.024
O&M Vari. Cost Factor	$/MWh	0.8	0.8	0.8	0.8	0.8	0.8	0.8
O&M Costs – Fixed	$M/a	0.900	1.350	1.800	2.700	3.600	4.500	7.200
O&M Costs – Variable.	$M/a	0.210	0.315	0.420	0.631	0.841	1.051	1.682
– Water Supply	$M/a	0.000	0.000	0.000	0.000	0.000	0.000	0.000
– Total	$M/a	0.210	0.315	0.420	0.631	0.841	1.051	1.682
Total O&M Costs	**$M/a**	1.110	1.665	2.220	3.331	4.441	5.551	8.882
O&M Unit Cost	**c/kWh**	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Fuel GHV (MJ/m3 for gas)	GJ/t	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Unit Heat Rate Gen.	GJ/MWh	9.85	9.85	9.85	9.85	9.85	9.85	9.85
Unit Heat Rate SO	GJ/MWh	10.61	10.61	10.61	10.61	10.61	10.61	10.61
Fuel Cons. – Tonnage(Mm3)	kt/a	301.0	451.5	602.0	903.0	1204.0	1505.0	2408.0
– Heat	TJ/a	2589	3883	5177	7766	10354	12943	20709
Fuel Price Delivered	$/t	8.6	8.6	8.6	8.6	8.6	8.6	8.6
	c/GJ	100	100	100	100	100	100	100
Fuel Cost	**$M/a**	2.589	3.883	5.177	7.766	10.354	12.943	20.709
Fuel Unit Cost	**c/kWh**	1.21	1.21	1.21	1.21	1.21	1.21	1.21
TOTAL COSTS:								
Bulk Supply Cost	**$M/a**	59.917	64.338	68.759	77.600	86.441	95.283	121.807
Bulk Supply Unit Cost								
Capital	c/kWh	26.20	18.26	14.30	10.33	8.35	7.16	5.37
O&M	c/kWh	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Fuel	c/kWh	1.21	1.21	1.21	1.21	1.21	1.21	1.21
Total	**c/kWh**	**27.92**	**19.99**	**16.02**	**12.05**	**10.07**	**8.88**	**7.09**
Unitised Cost Structure								
Fixed Cost	$/kW/a	190.4	200.5	210.5	230.7	250.8	271.0	331.4
Variable Cost	$/kW/a	74.6	74.6	74.6	74.6	74.6	74.6	74.6
Total Cost	**$/kW/a**	**265.0**	**275.1**	**285.2**	**305.3**	**325.5**	**345.6**	**406.0**

APPENDIX B

472426

Davy McKee

TASMANIAN GAS DEVELOPMENT

CONTENTS

1.0 BACKGROUND

SAGASCO has proposed development of the "Yolla" gas and condensate field in the Bass Basin, to provide natural gas supply to northern Tasmanian industries and domestic consumers. The development would be underwritten by a base-load demand for gas from the Bell Bay thermal power station operated by the HEC.

The LPG and condensate produced along with the gas would contribute about half of the revenue required to justify the development, and would markedly increase Tasmania's self-sufficiency in transport fuels. The key to undertaking the development is provision of an economic gas market; however, the HEC is not convinced that base-loading Bell Bay power station on gas will reduce their average cost of power supply. The attached paper (Appendix A) provides further details of the SAGASCO proposal.

This document suggests a means of achieving a sufficiently large gas load to make the average cost of gas attractive for both the HEC and various industries which could be established in Tasmania.

Davy McKee has discussed this concept with Mr Michael Weldon, the Tasmanian Minister for Resources, Energy and Construction, the Tasmanian Development Authority, the HEC, SAGASCO and other potential principal players in a major gas development and utilisation scheme. This document has been prepared in response to requests for further information expressed by those parties.

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2.0 NEW PROPOSAL

An additional (or alternative) base-load demand could be provided by converting natural gas to petrochemicals, specifically to nitrogenous fertilisers. A plant producing 650 tonnes per day of ammonia, the first step to nitrogenous fertilisers, would consume approximately 7 Petajoules of natural gas per year. This is a significant addition to the markets of 4 PJ for industry and 13 PJ for Bell Bay power station estimated by SAGASCO. An ammonia plant of this size would be capable of replacing all the estimated imports of nitrogenous fertilisers to South-Eastern Australia for the mid-1990s.

A plant located in Tasmania could be competitive with nitrogenous fertiliser imports to Victoria and South Australia, because the average cost of producing gas reduces with the increasing scale of the operation. The cost of production facilities does not rise proportionately with the production capacity, since many of the costs, such as drilling gas producing wells, placing a production platform offshore, and laying offshore and onshore pipelines, are fixed and independent of the capacity of the equipment. Davy McKee's preliminary estimates indicate that the gas price required to make the SAGASCO scheme viable could be reduced by one-third, if an extra 7 PJ/year could be sold to an ammonia plant.

Another possibility is to build a larger, world-scale ammonia plant capable of supplying export markets. In such a case, a 1,650 tpd ammonia plant would consume up to 20 PJ/year and could be competitive in the export market by virtue of the low average gas price which the extra gas volume would permit.

Nitrogenous fertilisers imported to southern Australia are predominantly in the forms of urea and di-ammonium phosphate (DAP). Both are granular solids and could be exported from Tasmania to Victorian or South Australian ports by a small purpose-built bulk products vessel.

TASMANIAN GAS DEVELOPMENT
ECONOMICS

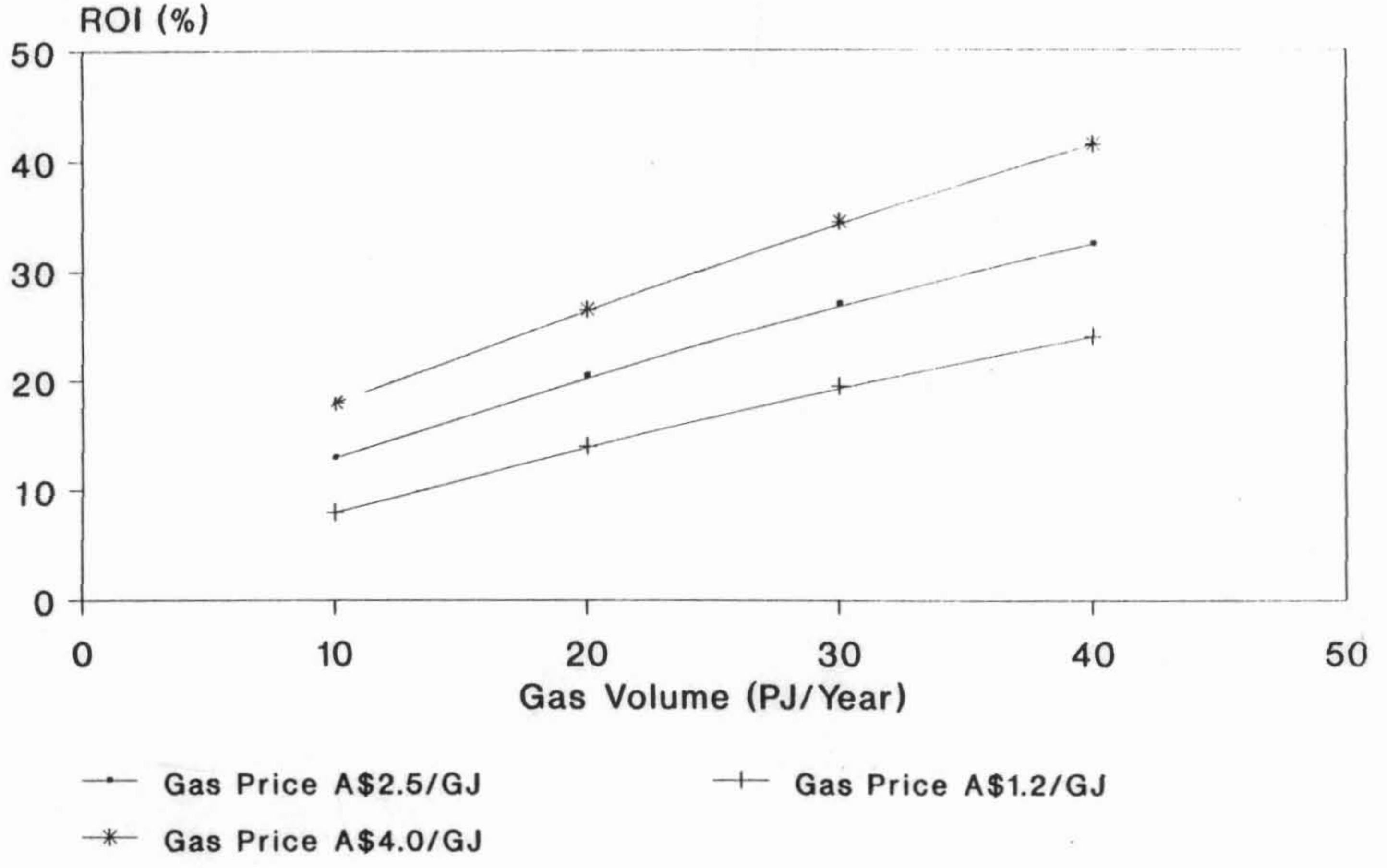

FIGURE 1.

5 cm

3.0 BENEFITS

As the average gas price declines with the addition of such projects, the cost of supplying gas to the HEC's Bell Bay power station declines, and at some point, base-load generation will be an attractive option. The attached graph (Figure 3.1) shows the effect on Return on Investment (before tax) and average gas price on increasing gas volumes.

Although not a large employer of labour, the nitrogenous fertiliser industry and the gas production development it requires is capital-intensive and therefore will add considerably to labour productivity in the State. The gas development itself could cost $650 million and the fertiliser plants $200-500 million, so the employment effect during construction would be highly significant.

Manufacture of nitrogenous fertilisers would assist local agriculture and call for further investment and growth in power demand and employment in Tasmania. Australia's imports could be reduced by $120 million per year, and exports of $150 million per year could be won.

Establishment of a large initial gas offtake which an ammonia plant provides would substantially assist the early cash flow and DCF return of the gas development project. A large contracted off-take would also assist project financing. The extra gas demand would increase the quantities of LPG and condensate produced, so Tasmania could become self-sufficient in transport fuels.

Provision of competitively-priced natural gas by this means would remove one of the major competitive disadvantages which Tasmania suffers in competing for industrial investments with other States. Subsequent conversion of ammonia to ammonium nitrate (explosive) and of urea to melamine (particle board coating) would complement the local mining and timber processing industries.

4.0 RECOMMENDATION

4.1 It is recommended that the gas development scheme proposed by SAGASCO be independently re-examined to determine the effect of adding extra gas demand by establishment of petrochemical industries in the Bell Bay area.

Nitrogenous fertiliser industries are proposed as the appropriate type of petrochemical industries to take advantage of domestic and export market opportunities in the 1990s.

A brief but wide-ranging study should be undertaken first to assess the economic viability of this concept, and to set out the further steps necessary to advance the development. It is anticipated that the study will demonstrate the incentive to undertake further exploratory drilling in the Bass Basin offshore northern Tasmania.

4.2 This study could be funded jointly by SAGASCO, a fertiliser manufacturer, the HEC and the Tasmanian Development Authority. It could be performed over two to four months, depending on the scope and detail required, commencing early in the fourth quarter of 1989. Davy McKee Pacific Pty Ltd offers itself to carry out such a study.

4.3 The study will aim to be of adequate depth and indicate economic viability sufficient to induce the following actions:

4.3.1 SAGASCO and its permit area partners to undertake additional reserve evaluation, including further seismic work and exploratory drilling.

4.3.2 The HEC to re-evaluate (a), the use of gas in Bell Bay power station and new combined-cycle gas turbine generation elsewhere in the northern part of the State, and (b), a DC power link to Victoria for peak power sales utilising hydro-generating capacity made available by thermal power generation (re-evaluation of a DC power link was recommended by a Victorian Parliamentary Committee in 1988, following a detailed enquiry into Victoria's electric power needs after the mid-1990s).

4.3.3 The fertiliser manufacturer to evaluate the location of ammonia/urea/DAP plants in Tasmania on two scales of operation, viz (a), to meet anticipated Australian domestic demand from the mid-1990s (approximately 650 tpd ammonia), and (b), to meet domestic and export opportunities (approximately 1,650 tpd ammonia).

4.3.4 The Tasmanian Government to evaluate its position in relation to such developments, particularly:

- its stance on environmental aspects
- the extent of facilitation it is prepared to extend, e.g. equity participation, loan guarantees, provision of land, water and port facilities, etc, negotiation of advantageous freight arrangements with the Commonwealth Government and the relevant unions.

Following consideration of the study report, it is recommended that the study sponsors meet to communicate their attitudes to the development proposal and indicate their commitment or otherwise to undertaking the actions necessary to advance it.

5.0 SCOPE OF ASSESSMENT STUDY

The assessment study could vary in scope, according to the interests of the study sponsors, and the time and funds devoted to its completion. The following outline sets out the issues which, in Davy McKee's experience, are appropriate at this stage of the development of the concept. The attached chart of activities and timing outlines a possible plan for the study.

5.1 Consolidate and summarise the information available from SAGASCO, HEC, TDA, and Davy McKee about the northern Tasmanian gas market potential, and the Yolla field development proposed by SAGASCO.

5.2 Review local and regional markets for ammonia, urea, DAP, ammonium nitrate (AN) and melamine. Further downstream processing options could also be canvassed.

5.3 Review or independently estimate the capital investments required for the 17 PJ/year gas development proposed by SAGASCO and two further cases corresponding to import replacement and export scale nitrogenous fertiliser projects. Estimate also the gas reserves required and liquids production for these cases as a basis for economic analysis.

5.4 Review Northern Tasmanian site options and transport considerations for supply of product to the agricultural cultivation areas of Victoria, South Australia and southern New South Wales. The excellent established industrial area alongside deep water at Bell Bay has obvious attractions in this context.

5.5 Review available technologies for manufacturing ammonia, urea and DAP, and estimate the capital investments and operating costs required in the two appropriate cases for analysis.

5.6 Review the likely environmental impacts of the larger gas developments and fertiliser manufacturing cases.

5.7 Evaluate the economic viability of the three gas development cases and the fertiliser plants as proposed.

5.8 Set out a plan to progress this development and/or recommend further areas for investigation.

TASMANIAN GAS & PETROCHEMICALS DEVELOPMENT

DRAFT STUDY PLAN

ACTIVITIES	WEEKS													
	01	02	03	04	05	06	07	08	09	10	11	12	13	14
Gather Data	▨	▨												
Review Markets			▨	▨										
Estimate Capex - Gas				▨	▨									
Review Tech & Estim Capex - Chem						▨	▨							
Review Transport								▨						
Review Site			▨											
Review Environment								▨	▨					
Evaluate Economics									▨	▨	▨			
Plan Development											▨	▨		
Report												▨	▨	▨

6.0 DAVY McKEE'S QUALIFICATIONS FOR THE STUDY ASSIGNMENT

Davy McKee is primarily a project manager of resource developments and major process industry undertakings. Its main fields of activity have been in oil and gas developments (offshore and onshore), petroleum refining, mineral processing and pulp and paper industries. A list of recent major projects and clients is in Appendix B.

Feasibility studies by Davy McKee are consequently very much action-orientated and practical. Studies and business plans have been prepared for Federal and State Governments on a broad range of subjects over many years.

Nitrogenous fertiliser markets within Australia and in Asia have ben studied extensively over recent years, including visits to potential ammonia and urea customers overseas. Links with various relevant technology licensors have been established, enabling rapid acquisition of technical and economic data as required.

Davy McKee is currently involved in studies and engineering for offshore oil and gas developments and onshore processing in Bass Strait, the Timor Sea, the North-West Shelf, and Denison Trough areas.

Davy McKee has extensive experience in environmental impact assessment and engineering for compliance, and is familiar with sea transport economics. Links with specialised consultants and operations in these areas ensure access to detailed information if required.

Its experience in project development planning and implementation, and its presence in Hobart makes Davy McKee uniquely placed to independently assess the development concept set out in this document.

The people who could be assigned to perform the study reflect this experience, and their CVs are in Appendix C.