NODAL OFFICER

RAVVA FIELD

PRODUCTION SHARING CONTRACT

BETWEEN

THE GOVERNMENT OF INDIA

AND

OIL & NATURAL GAS CORPORATION LTD

AND

VIDEOCON PETROLEUM LIMITED

AND

COMMAND PETROLEUM (INDIA) PTY LTD — Change of name from (prod) Command Petro (India) Pty Ltd to CAIRN Energy

AND

RAVVA OIL (SINGAPORE) PTE LTD

WITH RESPECT TO CONTRACT AREA

IDENTIFIED AS RAVVA OIL AND GAS FIELD

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APPENDICES:

Appendix A	Description of Contract Area (Article 1.22)
Appendix B	Map of Contract Area (Article 1.22)
Appendix C	Accounting Procedure to Production Sharing Contract (Article 1.1)
Appendix D	Calculation of the Post Tax Rate of Return for Production Sharing Purposes (Article 16.4)
Appendix E	Form of Performance Guarantee (Article 30)
Appendix F	Ravva Development Plan (Article 11.2)
Appendix G1	Approved Work Programme and Approved Budget for period from Effective Date to 31 March, 1995 (Article 5.5(a))
Appendix G2	Proposed Work Programme and Budget for period from 1 April, 1995 to 31 March, 1996 (Article 5.5(b))
Appendix H	Procedures For Acquisition of Goods and Services (Article 8.4)

This Contract made this 28th day of October 1994 between:

1. The President of India, acting through the Joint Secretary, Ministry of Petroleum and Natural Gas (hereinafter referred to as "Government"), of the FIRST PART;

AND

2. Oil & Natural Gas Corporation Ltd, a body corporate established under the Companies Act, 1956 having its registered office at 8th Floor, Jeevan Bharati, Tower II, 124 Connaught Circus, New Delhi, India (hereinafter referred to as "ONGC", which expression shall include its successors and assigns) acting through its duly authorised Chairman and Managing Director, of the SECOND PART;

AND

3 Videocon Petroleum Limited, a body corporate established under the Companies Act, 1956 having its registered office at 428-433, 4th Floor, Som Dutt Chambers-II, 9, Bhikaji Cama Place, New Delhi, India (hereinafter referred to as "Videocon", which expression shall include its successors and assigns) acting through its duly authorised Director, of the THIRD PART;

AND

4. Command Petroleum (India) Pty Ltd (ACN 002 066 784), a body corporate established under the laws of the State of New South Wales, Australia, and having its registered office at Level 1, 191 New South Head Road, Edgecliff, in the said State (hereinafter referred to as "Command", which expression shall include its successors and assigns) acting through its duly authorised Managing Director, of the FOURTH PART;

AND

5. Ravva Oil (Singapore) Pte Ltd (Company No. 199404403N), a body corporate established under the laws of the Republic of Singapore, Company No.199404403N, and having its registered office at 36 Robinson Road, #15-00 City House, Singapore, (hereinafter referred to as "Marubeni", which expression shall include its successors and assigns) acting through its duly authorised Managing Director, of the FIFTH PART;

WITNESSETH:

WHEREAS

(1) By virtue of Article 297 of the Constitution of India, Petroleum in its natural state in the Territorial Waters and the Continental Shelf of India is vested in the Union of India;

(2) The Oil Fields (Regulation and Development) Act, 1948 (53 of 1948) (hereinafter referred to as "the Act") and the Petroleum and Natural Gas Rules, 1959, made thereunder (hereinafter referred to as "the Rules") make provision inter alia for the regulation of Petroleum Operations and the grant of licences and leases for exploration and development of Petroleum in India;

(3) Exploration carried out by ONGC prior to the Effective Date pursuant to a Petroleum Exploration Licence under the Act and Rules has led to the discovery in the Contract Area of Petroleum in commercial quantities;

(4) The Government desires that the Petroleum resources in the Contract Area be exploited with the utmost expedition in the overall interest of India in accordance with good international petroleum industry practices;

(5) The Government had invited bids from persons interested in the development of Petroleum resources in the Contract Area;

(6) The Companies have represented that they have the necessary financial and technical resources and the technical and industrial competence and experience necessary for proper discharge and/or performance of all obligations required to be performed under this Contract in accordance with good international petroleum industry practices and each Company will provide a guarantee as required in Article 30 for the due performance of its undertakings hereunder;

(7) In the exercise of its powers under, and in accordance with the terms of, the Act and the Rules, the Government has granted a mining lease to ONGC and the Companies (as hereinafter defined) of even date herewith (hereinafter referred to as "the Lease") authorising ONGC and the Companies, inter alia, to carry out Petroleum Operations and activities ancillary thereto, in and relating to the Contract Area;

(8) The Government and ONGC have agreed to enter into this Contract with the Companies with respect to the conduct of Petroleum Operations (as hereinafter defined) in and relating to the Contract Area and pursuant to the Lease on the terms and conditions herein set forth.

NOW, THEREFORE, in consideration of the premises and covenants and conditions herein contained, IT IS HEREBY AGREED between the Parties as follows:

ARTICLE 1

DEFINITIONS

In this Contract, unless the context requires otherwise, the following terms shall have the meaning ascribed to them hereunder:

1.1 "Accounting Procedure" means the principles and procedures of accounting set out in Appendix C.

1.2 "Affiliate" means a company that directly or indirectly controls or is controlled by a Party to this Contract or a company which directly or indirectly controls or is controlled by a company which controls a Party to this Contract, it being understood that "control" means ownership by one company of more than fifty percent (50%) of the voting securities of the other company, or the power to direct, administer and dictate policies of the other company even where the voting securities held by such company exercising such effective control in that other company is less than fifty percent (50%) and the term "controlled" shall have a corresponding meaning.

1.3 "Appendix" means an appendix attached to this Contract and made a part thereof.

1.4 "Appraisal Programme" means a programme, approved by the Government or Management Committee, as the case may be, for the appraisal of a New Discovery of Petroleum in the Contract Area for the purpose of delineating the Reservoirs to which the Discovery relates in terms of thickness and lateral extent and determining the characteristics thereof and the quantity of recoverable Petroleum therein.

1.5 "Appraisal Well" means a Well drilled within the Contract Area pursuant to an Appraisal Programme.

1.6 "Approved Budget" means a Budget that has been approved by the Management Committee with respect to an Approved Work Programme.

1.7 "Approved Work Programme" means a Work Programme that has been approved by the Management Committee.

1.8 "Arms Length Sales" means sales of Petroleum made freely on the open international market, in freely convertible currencies, between willing and unrelated sellers and buyers and in which such buyers and sellers have no contractual or other relationship, directly or indirectly, or any common or joint interest as is reasonably and likely to influence selling prices and shall, inter alia, exclude sales (whether direct or

indirect, through brokers or otherwise) involving Affiliates, sales between entities comprising the Contractor, sales between governments and government-owned entities, counter trades, restricted or distress sales, sales involving barter arrangements and generally any transactions motivated in whole or in part by considerations other than normal commercial practices.

1.9 "Article" means an article of this Contract and the term "Articles" means more than one Article.

1.10 "Associated Natural Gas" or "ANG" means Natural Gas occurring in association with Crude Oil either as free gas or in solution, if such Crude Oil can by itself be commercially produced.

1.11 "Barrel" means a quantity or unit equal to 158.9074 litres (forty two (42) United States gallons) liquid measure, at a temperature of sixty (60) degrees Fahrenheit (15.56 degrees Centigrade) under one atmosphere of pressure (14.7 p.s.i.a.).

1.12 "Basement" means any igneous or metamorphic rock, or rock or any stratum of such nature, in and below which the geological structure or physical characteristics of the rock sequence do not have the properties necessary for the accumulation of Petroleum in commercial quantities and which reflects the maximum depth at which any such accumulation can be reasonably expected in accordance with the knowledge generally accepted in the international petroleum industry.

1.13 "Budget" means a budget formulated in relation to a Work Programme.

1.14 "Business Day" means a day on which banks are normally open for business in Sydney, Australia; Madras, India; Tokyo, Japan; and Singapore.

1.15 "Calendar Quarter" or "Quarter" means a period of three consecutive calendar months commencing on the first day of January, April, July and October of each calendar year.

1.16 "Cess" means cess levied pursuant to Section 15 of The Oil Industry (Development) Act, 1974.

1.17 "Commercial Discovery" means a New Discovery which has been declared a Commercial Discovery in accordance with the provisions of Article 19, after consideration of all pertinent operating and financial data such as recoverable reserves, sustainable production levels, estimated development and production expenditures, forecast prices and other relevant technical and economic factors according to generally accepted

practices in the international petroleum industry. For the avoidance of doubt, each of the Existing Discoveries is a Commercial Discovery.

1.18 "Commercial Production" means production of Crude Oil or Natural Gas or both from the Contract Area and delivery of the same at the relevant Delivery Point under a programme of regular production and sale.

1.19 "Company" for the purpose of this Contract means a company (excluding ONGC) which is a Party to this Contract and, the term "Companies" shall mean all such Companies (excluding ONGC) collectively, including their respective successors and such assigns as are permitted under Article 29.

1.20 "Condensate" means those low vapour pressure hydrocarbons obtained from Natural Gas through condensation or extraction and refers solely to those hydrocarbons that are liquid at normal surface temperature and pressure conditions, provided that in the event Condensate is produced from an Oil Field and is segregated and transported separately to the Delivery Point, then the provisions of this Contract shall apply to such Condensate as if it were Crude Oil.

1.21 "Contract" means this agreement and the Appendices mentioned herein and attached hereto and made an integral part hereof and any amendments made thereto pursuant to the terms hereof.

1.22 "Contract Area" means, on the Effective Date, the area described in Appendix A and delineated on the map attached as Appendix B, or any portion of the said area remaining after relinquishment or surrender from time to time pursuant to the terms of this Contract.

1.23 "Contract Costs" means costs incurred by the Contractor in accordance with the provisions of this Contract in connection with Petroleum Operations including, without limitation, Exploration Costs, Development Costs and Production Costs, and all payments made by Contractor pursuant to Article 17.2.

1.24 "Contract Year" means a period of twelve consecutive months counted from the Effective Date or from the anniversary of the Effective Date.

1.25 "Contractor" means the Companies and ONGC collectively.

1.26 "Cost Petroleum" means the portion of the total volume of Petroleum produced and saved from the Contract Area which the Contractor is entitled to take in a particular period for the recovery of Contract Costs as provided in Article 15.

1.27 "Crude Oil" means crude mineral oil, asphalt, ozokerite and all kinds of hydrocarbons and bitumens, both in solid and in liquid form, in their natural state or obtained from Natural Gas by condensation or extraction, including distillate and Condensate but excluding Natural Gas.

1.28 "Delivery Period" has the meaning ascribed to that expression in Article 20.2.

1.29 "Delivery Point" means, except as otherwise herein provided or as may be otherwise agreed between the Parties, the point at which Petroleum reaches the outlet flange of the delivery facility, either offshore or onshore and different Delivery Points may be established by decision of the Management Committee for purposes of sales to the Government and export sales or for any other purposes.

1.30 "Development Costs" means those costs and expenditures incurred in carrying out Development Operations, as classified and defined in Section 2 of the Accounting Procedure and allowed to be recovered in terms of Section 3 thereof.

1.31 "Development Operations" means operations conducted in accordance with the Development Plan and shall include the purchase, shipment or storage of equipment and materials used in developing Petroleum accumulations, the drilling, completion and testing of Development Wells, the drilling and completion of Wells for gas or water injection, the laying of gathering lines, the installation of offshore platforms and installations, the installation of separators, tankage, pumps, artificial lift and other producing and injection facilities required to produce, process and transport Petroleum into main oil storage or gas processing facilities, either onshore or offshore, including the laying of pipelines within or outside the Contract Area, storage and Delivery Point or Points, the installation of said storage or gas processing facilities, the installation of export and loading facilities and other facilities required for the development and production of the said Petroleum accumulations and for the delivery of Crude Oil and/or Gas at the Delivery Point and also including incidental operations not specifically referred to herein as required for the most efficient and economic development and production of the said Petroleum accumulations in accordance with good international petroleum industry practices.

1.32 "Development Plan" means:

(a) in relation to the Existing Discoveries, the Ravva Development Plan; and

(b) in relation to a New Discovery, a plan submitted by the Contractor containing proposals required under Article 10 or Article 22 for the development of a Commercial Discovery which has been approved by the Management Committee or Government.

1.33 "Development Well" means a Well drilled, deepened or completed after the date of approval of the Development Plan pursuant to Development Operations or Production Operations for the purposes of producing Petroleum, increasing production, sustaining production or accelerating extraction of Petroleum including production Wells, injection Wells and dry Wells.

1.34 "Discovery" means the finding, during Petroleum Operations, of a deposit of Petroleum not previously known to have existed, which can be recovered at the surface in a flow measurable by conventional petroleum industry testing methods.

1.35 "Discovery Area" means that part of the Contract Area about which, based upon Discovery and the results obtained from a Well or Wells drilled in such part and any other relevant information, both ONGC and the Companies are of the opinion that Petroleum exists and is likely to be produced in commercial quantities.

1.36 "Effective Date" means the date on which this Contract is executed by the Parties.

1.37 "Environmental Clearance" means a permission granted in writing by the Ministry of Environment and Forestry or his designate to the Contractor to perform all activities necessary and appropriate to conduct Petroleum Operations subject to conditions specified with regard to protection of the environment and minimizing Environmental Damage.

1.38 "Environmental Damage" means soil erosion, removal of vegetation, destruction of wildlife, pollution of groundwater or surface water, land contamination, air pollution, noise pollution, bush fire, disruption to water supplies or to natural drainage or natural flow of rivers or streams, damage to archaeological, palaeontological and cultural sites and shall include any damage or injury to, or destruction of, soil or water in their physical aspects together with vegetation associated therewith, aquatic or terrestrial mammals, fish, avifauna or any plant or animal life whether in the sea or in any other water or on, in or under land,

in violation of laws and regulations relating to the protection of the environment.

1.39 "Existing Discovery" means a Discovery referred to in Article 11.

1.40 "Exploration Costs" means those costs and expenditures incurred in carrying out Exploration Operations, as classified and defined in Section 2 of the Accounting Procedure and allowed to be recovered in terms of Section 3 thereof.

1.41 "Exploration Operations" means operations conducted pursuant to this Contract in searching for Petroleum in the Contract Area and in the course of an Appraisal Programme and shall include but not be limited to aerial, geological, geophysical, geochemical, palaeontological, palynological, topographical and seismic surveys, analysis, studies and their interpretation, investigations relating to the subsurface geology including structure test drilling, stratigraphic test drilling, drilling of Exploration Wells and Appraisal Wells and other related activities such as surveying, drill site preparation and all work necessarily connected therewith that is conducted in connection with Petroleum exploration.

1.42 "Exploration Well" means a Well drilled for the purpose of searching for undiscovered Petroleum accumulations on any geological entity (be it of structural, stratigraphic, facies or pressure nature) to at least a depth or stratigraphic level specified in the Approved Work Programme.

1.43 "Field" means an Oil Field or a Gas Field.

1.44 "Financial Year" means the period from the first day of April to the thirty-first day of March of the following calendar year.

1.45 "Foreign Company" means a Company within the meaning of Section 591 of the Companies Act, 1956, as amended from time to time.

1.46 "Gas" means Natural Gas.

1.47 "Gas Field" means an area within the Contract Area consisting of a single Gas Reservoir or multiple Gas Reservoirs all grouped on or related to the same individual geological structure or stratigraphic conditions, approved by the Management Committee (to include the maximum area of potential productivity in the Contract Area in one or more simple geometric shapes) in respect of which a Commercial Discovery has been declared.

1.48 "Government Company" means a company defined under Section 619 of the Companies Act, 1956 as amended from time to time.

1.49 "Gross Negligence" means any wilful act or failure to act (whether sole, joint or concurrent) by a Party which was intended to cause, or which was in reckless disregard of or wanton indifference to, harmful consequences such Party knew, or should have known, such act or failure would have had on another person or entity, but shall not include any error of judgement or mistake made by such Party in the exercise in good faith of any function, authority or discretion conferred on the Party under this Contract.

1.50 "Lessee" means any person or body corporate which holds a mining lease under the Petroleum and Natural Gas Rules, 1959, for the purpose of carrying out Petroleum Operations in the Contract Area and their successors and permitted assigns.

1.51 "LIBOR" means the London Inter Bank Offering Rate for six month deposits of US Dollars as quoted by the London office of the Bank of America (or such other bank or banks as the Parties may agree) for the day or days in question.

1.52 "Management Committee" means the committee constituted pursuant to Article 6 hereof.

1.53 "Natural Gas" means wet gas, dry gas, all other gaseous hydrocarbons, and all substances contained therein, including sulphur and helium, which are produced from Oil or Gas Wells, excluding those condensed or extracted liquid hydrocarbons that are liquid at normal temperature and pressure conditions, and including the residue gas remaining after the condensation or extraction of liquid hydrocarbons from Gas.

1.54 "New Discovery" means a Discovery other than an Existing Discovery.

1.55 "Non Associated Natural Gas" or "NANG" means Natural Gas which is produced either without association with Crude Oil or in association with Crude Oil which by itself cannot be commercially produced.

1.56 "Oil" means "Crude Oil".

1.57 "Oil Field" means an area within the Contract Area consisting of a single Oil Reservoir or multiple Oil Reservoirs all grouped on or related to the same individual geological structure, or stratigraphic conditions, approved by the Management Committee (to include the maximum area of potential productivity in the Contract Area in one or more simple geometric

shapes) in respect of which a Commercial Discovery has been declared and a Development Plan has been approved and a reference to an Oil Field shall include a reference to the production of Associated Natural Gas from that Oil Field.

1.58 "Operating Agreement" means the Joint Operating Agreement entered into by the Companies and ONGC in accordance with Article 7, with respect to the conduct of Petroleum Operations.

1.59 "Operating Committee" means the committee established by that name in the Operating Agreement pursuant to Article 7.

1.60 "Operator" means the Party appointed as Operator pursuant to Article 7.

1.61 "Participating Interest" means, in respect of each Party constituting the Contractor, the undivided share, expressed as a percentage, of such Party in the rights and obligations under this Contract, the Operating Agreement, and the Lease.

1.62 "Parties" means the parties signatory to this Contract including their successors and permitted assigns under this Contract and the term "Party" means any of the Parties.

1.63 "Past Costs" means the costs incurred by ONGC in the construction of development and production facilities to achieve the level of Crude Oil production from the Contract Area current as at the Effective Date, including the costs of the Ravva 10, 12, 17, 27, 34, 35, 36 and 37 wells, less the value of Crude Oil production from the Contract Area up to the Effective Date, net of associated Production Costs, Royalty and Cess. The Parties agree that the provisions of Article 20 shall apply mutatis mutandis in determining the value of such production.

1.64 "Petroleum" means Crude Oil and Natural Gas existing in their natural condition.

1.65 "Petroleum Operations" means, as the context may require, Exploration Operations, Development Operations or Production Operations or any combination of two or more of such operations, including construction, operation and maintenance of all necessary facilities, plugging and abandonment of Wells, environmental protection, transportation, storage, sale or disposition of Petroleum to the Delivery Point, Site Restoration and all other incidental operations or activities as may be necessary.

1.66 "Post Tax Rate of Return" or "PTRR" means, in relation to the Contract Area, the after tax return per annum as determined in accordance with Appendix D.

1.67 "Production Costs" means those costs and expenditures incurred in carrying out Production Operations as classified and defined in Section 2 of the Accounting Procedure and allowed to be recovered in terms of Section 3 thereof.

1.68 "Production Operations" means all operations conducted for the purpose of producing Petroleum from the Contract Area pursuant to this Contract after the commencement of production from the Contract Area, including the operation and maintenance of all necessary facilities therefor.

1.69 "Programme Quantity" shall have the meaning assigned in Article 10.15.

1.70 "Profit Petroleum" means all Petroleum produced and saved from the Contract Area in a particular period as reduced by Cost Petroleum and calculated as provided in Article 16.

1.71 "Ravva Development Plan" means the plan referred to in Article 11.

1.72 "Reservoir" means a naturally occurring discrete accumulation of Petroleum.

1.73 "Royalty" means the royalty payable pursuant to Section 6A(2) of The Oilfields (Regulation and Development) Act, 1948 and Rule 14 of The Petroleum and Natural Gas Rules, 1959, as amended from time to time.

1.74 "Satellite Field" means a field referred to in Article 11.4(a).

1.75 "Section" means a section of the Accounting Procedure.

1.76 "Self-sufficiency" means, in relation to any Year, that the volume of Crude Oil and Crude Oil equivalent of Petroleum products exported from India during that Year either equals or exceeds the volume of Crude Oil and Crude Oil equivalent of Petroleum products imported into India during the same Year.

1.77 "Site Restoration" shall mean all activities required to return a site to its natural state or to render a site compatible with its intended after-use (to the extent reasonable, having regard to its former use, if any, and state), after cessation of Petroleum Operations in relation thereto and shall include, where appropriate, proper abandonment of wells or other facilities, removal of equipment, structures and debris, establishment of

compatible contours and drainage, replacement of top soil, revegetation, slope stabilisation, infilling of excavations or any other appropriate actions in the circumstances.

1.78 "Subcontractor" means any company or person contracted by the Operator to provide goods or services with respect to Petroleum Operations.

1.79 "Transfer Period" means any period as described in Article 7.5.

1.80 "Transfer Period Net Revenue" means the value of Petroleum produced and saved from the Contract Area during the Transfer Period, calculated in accordance with Articles 20 and 22, less associated Production Costs, Royalty, Cess and sales tax (if applicable).

1.81 "US$" or "US Dollars" or "United States Dollars" means the currency of the United States of America

1.82 "Well" means a borehole, made by drilling in the course of Petroleum Operations, but does not include a seismic shot hole.

1.83 "Work Programme" means a programme formulated for the performance of Petroleum Operations.

1.84 "Year" means Financial Year.

ARTICLE 2

DURATION

2.1 The duration of this Contract shall be for a period of twenty five (25) years from the Effective Date, unless the Contract is terminated earlier in accordance with its terms, but may be extended by the Government for a further period not exceeding five (5) years; provided that in the event of Commercial Production of Non Associated Natural Gas, the Contract may be extended for a period up to but not exceeding thirty five (35) years from the Effective Date.

ARTICLE 3

INITIAL PARTICIPATING INTERESTS, RELATIONSHIP OF PARTIES AND ONGC CARRY

3.1 Initial Participating Interests

The initial Participating Interests of the Parties (other than Government) are as follows:

ONGC	40.0%
Videocon	25.0%
Command	22.5%
Marubeni	12.5%

3.2 Several Liability

The rights, covenants, obligations and responsibilities of the Parties pursuant to or arising under this Contract shall be several and not joint nor joint and several. Further and except as expressly provided in this Contract, nothing herein contained shall be construed to create an association, trust or partnership, between the Parties. Each Party shall be individually responsible for its own covenants, obligations and responsibilities to the extent of its Participating Interest except as herein expressly provided. No Party shall be under the control of or the agent of or have a right or power to bind any other Party without its express written consent, except as herein expressly provided. Nothing in this Article 3.2 shall prevent the Government from taking action against a Party comprising Contractor in respect of any breach by such Party of its obligations under this Contract or from joining all Parties comprising Contractor in a single action PROVIDED ALWAYS THAT any liability imposed on such Party or Parties shall be limited to its or their Participating Interest share or shares of such liability.

3.3 ONGC Carry

In consideration of ONGC having paid the Past Costs, the Companies covenant to ONGC that they shall:

(a) during the Transfer Period, pay the share of Exploration Costs, Development Costs and Production Costs incurred by the Operator; and

(b) after the Transfer Period, pay the share of Contract Costs,

that would otherwise be payable by ONGC, in the proportion that their respective Participating Interests bear to their total Participating Interests, until such

time as the amount paid by the Companies pursuant to this Article 3.3 equals the amount that is equivalent to the Companies' total Participating Interest share of the difference between Past Costs and Transfer Period Net Revenue PROVIDED THAT the Companies' obligations under this Article 3.3 shall not exceed the sum of thirty three million US Dollars (US$33 million) less an amount equivalent to the Companies' total Participating Interest share of Transfer Period Net Revenue to which but for Article 7.5(c) the Companies would otherwise be entitled. Thereafter, Contract Costs shall be borne and paid by the Companies and ONGC in proportion to their Participating Interests.

3.4 Adjustments Regarding ONGC Carry

Should the cumulative amount provided by the Companies pursuant to Article 3.3 at the end of the Transfer Period exceed the Companies' total Participating Interests share of the difference between Past Costs and Transfer Period Net Revenue, then any such excess shall be repaid by ONGC out of one hundred percent (100%) of ONGC's net proceeds from the sale of its Participating Interest share of Petroleum.

ARTICLE 4

RELINQUISHMENT

4.1 Voluntary Relinquishment of Contract Area

Contractor may, with the approval of the Management Committee, voluntarily relinquish a portion of the Contract Area other than an area for which a Development Plan has been approved.

4.2 Relinquishment of Contract Area Consequent on Termination

If the Contract is terminated under the provisions of Article 31 or in accordance with any other provisions of this Contract, the entire Contract Area remaining with the Contractor shall be deemed to have been relinquished by the Contractor as on the date on which the Contract is terminated.

4.3 Prior Liabilities Not Affected

Relinquishment of the entire or a part of the Contract Area or termination of the Contract shall not be construed as absolving the Contractor of any liability undertaken or incurred by the Contractor in respect of the Contract Area prior to the date of such relinquishment or termination. Any liability of the Contractor shall be limited to causes of action arising out of Contractor's conduct of Petroleum Operations during the period between the Effective Date and the date of such relinquishment or termination as the case may be.

ARTICLE 5

WORK PROGRAMMES AND BUDGETS AND EMERGENCY EXPENDITURE

5.1 Commencement of Operations

The Contractor shall commence Petroleum Operations not later than six (6) months from the Effective Date.

5.2 Submission of Work Programmes and Budgets

Subject to Article 5.5, as soon as possible after the Effective Date, in respect of the period ending with the last day of the Year in which the Effective Date falls and thereafter ninety (90) days before commencement of each following Year, the Contractor shall submit to the Management Committee, through the Operating Committee, the proposed Work Programme and Budget relating to Petroleum Operations to be carried out during the ensuing Year.

5.3 Management Committee Approval of Work Programmes and Budgets

The proposed Work Programme and Budget shall be considered by the Management Committee within thirty (30) days after submission thereof pursuant to Article 5.2. The proposed Work Programme and Budget, revised in accordance with any amendments agreed by the Parties, and approved by the Management Committee shall be adopted as the Approved Work Programme and Approved Budget relating to Petroleum Operations to be carried out during the Year to which they relate and the Contractor shall promptly commence implementation thereof.

5.4 Amendments to Work Programmes and Budgets

The Contractor may propose material modifications or revisions to an Approved Work Programme and Approved Budget in the light of the then existing circumstances and shall submit same to the Management Committee for approval, through the Operating Committee. Such modifications or revisions shall be considered by the Management Committee within thirty (30) days after their submission and, to the extent same are approved, the Approved Work Programme and Approved Budget shall be deemed to be amended accordingly.

5.5 Approved Work Programme and Budget For Period From Effective Date to 31 March 1995 and Proposed Work Programme and Budget For Period From 1 April, 1995 to 31 March, 1996

(a) Appendix G1 to this Contract shall constitute the Approved Work Programme and Approved Budget for the period from the Effective Date to 31st March 1995, and shall be deemed to have been approved by the Management Committee.

(b) Appendix G2 to this Contract is the Contractor's proposed Work Programme and Budget for the period from 1 April, 1995 to 31 March, 1996 ("the 95/96 year"). The Parties acknowledge and agree that it is their intention to adopt a Work Programme and Budget for the 95/96 year on or before 30 November, 1994 and to this end agree that they shall use their best endeavours to ensure that all necessary discussions of the Management Committee regarding Appendix G2 take place prior to 30 November, 1994 so as to enable the Management Committee to approve the Work Programme and Budget contained in Appendix G2 (with such modifcations as the Management Committee may require) by that date.

5.6 Emergency Expenditure

(a) Notwithstanding any other provision in this Contract to the contrary, but without prejudice to the provisions of Article 14.7(c), in case of emergency, the Operator may do such things and make such immediate expenditures as it deems necessary for the protection of life, property or the environment. Such expenditures shall be reported promptly to the Management Committee.

(b) The Approved Work Programme and Approved Budget shall be deemed to be amended to reflect the work and expenditures referred to in Article 5.6(a).

ARTICLE 6

MANAGEMENT COMMITTEE

6.1 Constitution of Management Committee

There shall be constituted a committee to be called the Management Committee which shall exercise overall supervision and control over all matters pertaining to Petroleum Operations including those relating to general policies, procedures and methods of operation under this Contract.

6.2 Appointment and Authority of Members

The Management Committee shall consist of one member nominated by and representing each Party comprising Contractor, and one member nominated by and representing the Government. Each Party shall nominate its member by notice to each other Party within fifteen (15) days of the Effective Date. A member shall be deemed authorised to bind the Party nominating such member for the purposes of this Contract.

6.3 Convenor and Chairman

The member nominated by the Operator shall be designated as the Convenor of the Management Committee ("the Convenor"). The member nominated by ONGC shall act as Chairman of the Management Committee ("the Chairman").

6.4 Alternate Member

Each party may nominate an alternate member with full authority to act in the absence and on behalf of the member nominated under Article 6.2 and may, at any time, nominate another member or alternate member to replace any member nominated earlier by notice to other members of the Management Committee.

6.5 Matters Requiring Management Committee Approval

The following matters shall be submitted to the Management Committee for approval:

(a) Subject to Articles 5.5 and 5.6, Work Programmes and Budgets and any material modifications or revisions thereto, as proposed by the Operating Committee, for Development Operations and Production Operations;

(b) proposals for an Appraisal Programme, the declaration of a New Discovery as a Commercial Discovery and the approval of Development Plans as may be required under this Contract, or material

revisions or additions to an Appraisal Programme or a Development Plan;

(c) delineation of a Field;

(d) appointment of auditors;

(e) collaboration with lessees or contractors of other areas;

(f) claims or settlement of claims for or on behalf of or against the Contractor in excess of limits specified in the Operating Agreement or fixed by the Management Committee from time to time;

(g) any other matter required by the terms of this Contract to be submitted for the approval of the Management Committee;

(h) any other matter which the Contractor or the Operating Committee decides to submit to it; and

(i) any other matter which the Management Committee decides should be submitted to it.

6.6 Government Approvals

The Management Committee shall not take any decision without obtaining prior approval of the Government where such approval is required under this Contract (other than in its capacity as a Party).

6.7 Meetings of Management Committee

The Management Committee shall meet at least once every three (3) months or more frequently at the request of any member. The Convenor shall convene each meeting by notifying the members at least twenty eight (28) days prior to such a meeting (or a shorter period of notice if the members unanimously so agree) of the time and place of such meeting and the purpose thereof and shall include in such notice a provisional agenda for such meeting. The Convenor, in consultation with the other members, shall be responsible for processing the final agenda for such meeting and the agenda shall include all items of business requested by the members to be included, provided such requests are received by the Convenor at least ten (10) days prior to the date fixed for the meeting. The Convenor shall forward the agenda to the members at least nine (9) days prior to the date fixed for the meeting. Matters not included in the agenda may be taken up at the meeting by any member with the unanimous consent of all the members (whether present at the meeting or otherwise).

6.8 Chairman to Preside

The Chairman or, in his absence, any other member as may be agreed by the members present at the meeting shall preside over the meetings of the Management Committee

6.9 Minutes

The Convenor shall be responsible for the preparation of the minutes of every meeting in the English language and provision to every member of the Management Committee with one (1) copy of the minutes not later than twenty eight (28) days after the date of the meeting.

6.10 Approval of Minutes

Within twenty one (21) days of the receipt of the minutes of a meeting, members shall notify the Convenor of their approval of the minutes by telex or facsimile transmission, with copies to the other members. Any member may suggest any modification, amendment or addition to the minutes by telex or facsimile transmission to the Convenor and other members. If the Convenor or any other member does not agree with the modification, amendment or addition to the minutes suggested by any member, the matter shall be brought to the attention of the other members and resubmitted to the Management Committee at the next meeting and the minutes shall stand approved as to all other matters. If a member fails to appropriately respond within the aforesaid twenty one (21) day period as herein provided, the minutes shall be deemed approved by such member.

6.11 Place of Meetings

The meetings of the Management Committee shall be held in Madras, India, unless otherwise agreed by the Management Committee.

6.12 Unanimous Approval Required

(a) Except as provided in Article 6.12(b), all decisions of the Management Committee (including any approvals or consents) shall be by a unanimous vote of all the members (including the Chairman) of the Management Committee.

(b) In the event that a Defaulting Party (as defined in Article 7.6(i) of the Operating Agreement) is, pursuant to the provisions of Article 7.7(i) of the Operating Agreement, not entitled to vote at meetings of the Management Committee, determinations of the Management Committee shall be made by unanimous vote of the members of the Management Committee other than the member

appointed by the said Defaulting Party and any vote or purported vote by such member shall be ignored. The said Defaulting Party shall be bound by all determinations of the Management Committee.

(c) The Parties expressly acknowledge that decisions of the Management Committee should be made in a timely manner to ensure that Petroleum Operations may be conducted as cost efficiently as possible and without unnecessary delay. Accordingly, the Parties agree to use their best endeavours to ensure that the Management Committee expeditiously considers and decides all matters which are required to be considered and decided by it pursuant to the provisions of this Contract.

6.13 Sub-Committees

The Management Committee may appoint legal, financial, marketing or technical subcommittees or such other sub-committees as the Management Committee considers desirable, comprised of such persons as may be agreed by the Management Committee, to consider and make any recommendations regarding any matter requiring approval or decision of the Management Committee.

6.14 Expenses of Members

Unless otherwise agreed by the Management Committee, all expenses incurred by a member or his advisers in attending Management Committee or sub-committee meetings shall be borne by the Party whom such member or adviser represents provided, however, the costs of such advisers as Operator considers reasonably necessary to ensure that the Management Committee is properly informed shall be recoverable as Contract Costs.

6.15 Entitlement to Cast Vote by Telex or Facsimile

Any member shall be entitled, if neither he nor his alternate is able to attend a meeting, to cast his vote by telex or facsimile transmission received by the Convenor prior to the time that the vote is taken in the course of the meeting. Such vote shall have the same effect as if that member had been present and so voted at the meeting.

6.16 Appointment of Proxy

Any member may, by notice to all other members, appoint a member representing another Party, who consents to such appointment, as its proxy to attend a meeting and to exercise the appointing member's right to vote at that meeting. A member appointed as a proxy and attending a meeting shall be present in two separate capacities and may vote accordingly.

6.17 Submission in Lieu of Meeting

(a) Without prejudice to Article 6.7, where the Operating Committee has agreed that a recommendation be made to the Management Committee, the Convenor may, when in his reasonable opinion it is not practical or appropriate to incur a delay in convening a meeting, submit the recommendation (together with the reasons for the recommendation) for consideration by the Management Committee by giving each member notice by telex or facsimile transmission, receipt of which shall be confirmed by telephone by the Convenor (or, in case of an emergency, by telephone confirmed by telex or facsimile transmission not later than the next Business Day).

(b) In the case of any recommendation submitted to the members for decision pursuant to Article 6.17(a):

(i) subject to paragraph (ii) of this Article 6.17(b) the members shall vote, by telex or facsimile transmission to the Convenor, with a copy to the other members:

(aa) within 24 hours of service of notice in the case of an emergency; or

(bb) in any other case, within a time nominated in the notice being reasonable in the circumstances but not less than five (5) Business Days from the date of service of the notice.

(ii) Except in the case of an emergency, a member may, within 48 hours of the service of the notice of the proposal, require by a further notice that the proposal be put to a meeting pursuant to Article 6.7.

(iii) Any member failing to vote within the time limits set out in Article 6.17(b)(i) shall be deemed to have voted in favour of the proposal.

(iv) The result of any such vote shall be notified by the Convenor to all the members.

ARTICLE 7

OPERATORSHIP, OPERATING AGREEMENT AND OPERATING COMMITTEE

7.1 Appointment of Command as Operator

(a) Command shall be the Operator for carrying out the Petroleum Operations pursuant to this Contract and the Operating Agreement from the Effective Date.

(b) Command agrees that it shall not resign as Operator until completion of Development Operations as contemplated in the Ravva Development Plan.

7.2 Operator to Perform Duties on Behalf of Contractor

The operating functions required of the Contractor under this Contract shall be performed by the Operator on behalf of all of the Parties comprising Contractor subject to, and in accordance with, the terms and provisions of this Contract and generally accepted international petroleum industry practice.

7.3 Change of Operatorship to be Approved by Government

(a) In the event that Command ceases to be the Operator, the Parties comprising Contractor covenant to the Government that they shall promptly procure the appointment of a replacement Operator who is technically and financially competent to act as an Operator.

(b) No change in operatorship shall be effected without the consent of the Government and such consent shall not be unreasonably withheld.

7.4 Operating Agreement

The Companies and ONGC shall execute a mutually agreed Operating Agreement. The Operating Agreement shall be consistent with the provisions of this Contract and shall provide for, among other things:

(a) the appointment, resignation, removal and responsibilities of the Operator;

(b) the establishment of an Operating Committee chaired by a representative of the Operator;

(c) functions of the said Operating Committee taking into account the provisions of the Contract, procedures for decision making, frequency and place of meetings; and

(d) Participating Interests, contribution to costs, default, disposal of petroleum, withdrawal, and assignment as between the parties to the Operating Agreement.

7.5 ONGC to Assist in Production Operations During Transfer Period

(a) Notwithstanding anything in this Article 7 or in the Operating Agreement to the contrary, the Parties agree that the Operator may request, by notice in writing, that ONGC second to the Operator ONGC personnel currently deployed in Production Operations to assist the Operator in carrying out such operations, under the direction and control of the Operator, for a maximum period of three (3) months from the Effective Date ("the Transfer Period"). Such notice shall specify the date of commencement and termination of the Transfer Period. ONGC shall be reimbursed the actual costs of employment of such secondees. Operator shall also be entitled to request ONGC to continue to provide ONGC services in relation to Production Operations during the Transfer Period. ONGC shall be entitled to be reimbursed the actual costs of providing such services. ONGC shall cooperate with Operator if Operator requires any contract entered into by ONGC with a third party to be assigned to Operator for the purposes of Production Operations.

(b) After the Transfer Period, ONGC shall second to the Operator such of ONGC's personnel, for such period and on such terms and conditions, as Operator and ONGC shall agree, in order to assist Operator in carrying out its obligations as Operator; and

(c) Notwithstanding any provision of this Contract to the contrary:

(i) ONGC shall be entitled to, and shall take, all Crude Oil produced and saved during the Transfer Period ("ONGC Crude") and be responsible for all associated Production Costs and all payments of Royalty, Cess and any applicable sales tax; and

(ii) all sales of ONGC Crude shall be at ONGC's sole cost and risk, including all liabilities arising out of the transportation of Crude Oil after delivery to ONGC at the Delivery Point at the existing onshore facility.

(d) (i) In relation to Command's performance of its obligations as Operator during the Transfer Period, the Parties acknowledge that Command will be assuming the role of Operator from the Effective Date without the benefit of a transition period.

(ii) ONGC agrees that it shall fully cooperate with Command in relation to Command's assumption of its obligations as Operator during the Transfer Period necessary to ensure a smooth transition.

ARTICLE 8

RIGHTS AND OBLIGATIONS OF THE PARTIES

8.1 Contractor's Rights and Covenant Regarding Lease

Subject to the provisions of this Contract, the Government covenants to Contractor that:

(a) Contractor shall have the following rights:

(i) the exclusive right to carry out Petroleum Operations in the Contract Area and to recover costs and expenses as provided in this Contract;

(ii) the right to use, free of charge, such quantities of Petroleum produced from any Field as are reasonably required for conducting Petroleum Operations in accordance with generally accepted practices in the international petroleum industry;

(iii) the right to lay, build, construct or install, pipelines (including oil and gas pipelines), roads, bridges, ferries, aerodromes, landing fields, radio telephones and related communication and infrastructure facilities and exercise other ancillary rights as may be reasonably necessary for the conduct of Petroleum Operations subject to such approvals as may be required pursuant to the applicable laws in force from time to time for the regulation and control thereof;

(iv) the right of full and free access to all data (including but not limited to technical data such as seismic, well information, maps, interpretative data, Crude Oil samples, cores and core data, and logs) in the possession or control of Government or ONGC as at the Effective Date. Such access shall be without cost to Contractor and shall include the right to copy such data at Contractor's cost. If requested by Contractor, ONGC shall provide personnel and/or facilities for copying or reproducing such data and ONGC shall be entitled to be reimbursed its actual costs of providing such personnel and/or facilities. ONGC shall respond promptly to any request by a Party for access to and copies of data in ONGC's possession or control;

(v) the right to a transfer of the land referred to in Article 21 of the Operating Agreement from ONGC to the Parties to the Operating Agreement (including ONGC) and, to the extent necessary, the Government hereby consents to and approves such transfer; and

(vi) such other rights as are specified in this Contract.

and

(b) The Lease has been duly issued in accordance with the Act, is in full force and effect and is sufficient authority to empower Contractor to conduct Petroleum Operations relating to the Contract Area.

8.2 Reservation of Mining Rights

The Government reserves the right to itself, or to grant to others the right, to prospect for and mine minerals or substances other than Petroleum within the Contract Area; provided, however, that if after the Effective Date, such others are issued rights, or the Government proceeds directly to prospect for and mine in the Contract Area any minerals or substances other than Petroleum, the Contractor shall use its best efforts to avoid obstruction to or interference with such operations within the Contract Area and the third parties and/or Government, as the case may be, shall use best efforts to ensure that operations carried out do not obstruct or unduly interfere with Petroleum Operations in the Contract Area.

8.3 Contractor's Obligations

The Contractor shall:

(a) except as otherwise expressly provided in this Contract, conduct all Petroleum Operations at its sole risk, cost and expense and provide all funds necessary for the conduct of Petroleum Operations including funds for the purchase or lease of equipment, materials or supplies required for Petroleum Operations as well as for making payments to employees, contractors and Subcontractors;

(b) conduct all Petroleum Operations within the Contract Area diligently, expeditiously, efficiently and in a safe and workmanlike manner in accordance with good international petroleum industry practice pursuant to the Approved Work Programmes;

(c) ensure provision of all information, data, samples etc. which the Lessee may be required to furnish under the applicable laws;

(d) ensure that all equipment, materials, supplies, plant and installations used by the Contractor, the Operator, and Subcontractors comply with generally accepted standards in the international petroleum industry and are of proper construction and kept in good working order;

(e) in the preparation and implementation of Work Programmes and in the conduct of Petroleum Operations, follow good international petroleum industry practices with such degree of diligence and prudence reasonably and ordinarily exercised by experienced parties engaged in a similar activity under similar circumstances and conditions;

(f) establish and submit to the Management Committee for approval appropriate criteria and procedures for the purchase, lease or rental of machinery, equipment, assets and facilities required for Petroleum Operations based on economic considerations and generally accepted practices in the international petroleum industry with the objective of ensuring cost and operational efficiency in the conduct of Petroleum Operations;

(g) establish and submit for the approval of the Management Committee appropriate procedures including tender procedures for the acquisition of goods and services as provided in Article 24;

(h) after the designation of a Field, pursuant to this Contract, forthwith proceed to take all necessary action for prompt and orderly development of the Field and for the production of Petroleum in accordance with the terms of this Contract;

(i) appoint a technically competent and sufficiently experienced person, and, in his absence, a suitably qualified replacement therefor, who shall be resident in India and who shall have full authority to take such steps as may be necessary to implement this Contract and whose names shall, on appointment within ninety (90) days after commencement of the first Contract Year, be made known to ONGC and the Government;

(j) provide acceptable working conditions, living accommodation and access to medical attention and nursing care for all personnel employed in Petroleum Operations related to the Contract Area; and

(k) carry out such other obligations as are specified in this Contract, in particular those specified in Article 14.

8.4 Agreed Tendering Procedures

In conformity with the provisions of Articles 8.3 (f) and 8.3 (g) the Parties hereby agree that the procedures set out in Appendix H hereto shall be the governing procedures with respect to the acquisition of goods and services for the carrying out of Petroleum Operations. No amendment of the procedures set out in Appendix H shall be made without the approval of the Management Committee.

8.5 Use of facilities by Government, Parties or Third Parties

All facilities constructed by Contractor pursuant to this Contract for the carrying out of Petroleum Operations may be made available for use by Government, third parties, or a Party, which wishes to use such facilities in respect of its Petroleum production operations outside of the Contract Area SUBJECT TO:

(a) the proposed use not, in the reasonable opinion of the Operator, interfering with Petroleum Operations;

(b) reasonable compensation for such use in accordance with international petroleum industry practice being paid to Contractor; and

(c) receipt of prior Management Committee approval, except in the case of emergency.

8.6 Representations and Warranties of Government

The Government hereby represents and warrants to Contractor that:

(a) the Government has the full power and authority to enter into this Contract and to perform the terms and conditions hereof and has taken all necessary action to authorise the execution, delivery and performance of this Contract; and

(b) the execution and delivery of this Contract and the performance of the transactions contemplated herein, in accordance with the terms and conditions hereof, will not contravene any existing provision of any law, statute, decree, rule, or regulation of India, including, without limitation, the Act and the Rules.

ARTICLE 9

GOVERNMENT ASSISTANCE

9.1 Government to Provide Assistance

Upon application in the prescribed manner, and subject to compliance with applicable laws and relevant procedures, the Government shall:

(a) provide the unrestricted right of ingress and egress from the Contract Area and any facilities used in Petroleum Operations, wherever located, and which may be within its control;

(b) use its good offices, when necessary, to assist Contractor in procurement of facilities required for execution of Work Programmes including necessary approvals, permits, consents, authorisations, visas, work permits, licences, rights of way, easement, surface rights and security protection, required pursuant to this Contract and which may be available from resources within its control;

(c) use its good offices to assist in identifying and making available necessary priorities for obtaining local goods and services pursuant to Article 24; and

(d) in the event that onshore facilities are required outside the Contract Area for Petroleum Operations including, but not limited to, storage, loading and processing facilities, pipelines and offices, use its good offices in assisting the Contractor to obtain from the authorities of the State Government in the State in which such facilities are required, such licences, permits, authorisations, consents, security protection, surface rights and easements as are required for the construction and operation of the said facilities by the Contractor.

9.2 Government to Assist Regarding Grant of Lease by Andhra Pradesh State

The Government shall use its best endeavours to procure that the Government of the State of Andhra Pradesh shall grant a petroleum mining lease to the Parties comprising Contractor in respect of that part of the Contract Area that is onshore the State of Andhra Pradesh. The Government shall further use its best endeavours to procure that such lease shall be substantially on terms identical to the terms of the Lease.

ARTICLE 10

NEW DISCOVERY, DEVELOPMENT AND PRODUCTION

10.1 Notification of New Discovery

If and when a New Discovery is made within the Contract Area, the Contractor shall:

(a) forthwith inform the Government of such Discovery;

(b) promptly thereafter, but in no event later than a period of thirty (30) days from the date of such Discovery, furnish to the Government particulars, in writing, of such Discovery; and

(c) promptly run tests to determine whether the New Discovery is of potential commercial interest and, within a period of sixty (60) days after completion of such tests, submit a report to the Management Committee containing data obtained from such tests and its analysis and interpretation thereof, together with a written notification to the Government of whether, in the Contractor's opinion, such New Discovery is of potential commercial interest and merits appraisal.

10.2 Notification of Proposed Testing

If the Contractor determines to conduct a drill stem or production test, in open hole or through perforated casing, with regard to any Discovery, the Operator shall notify all Parties comprising Contractor of the time of such test at least twenty four (24) hours prior to the proposed test, and each such Party shall have the right to have a representative present during such test at its sole risk and cost.

10.3 Contractor to Submit Appraisal Programme

If, pursuant to Article 10.1(c), the Contractor notifies the Government that a New Discovery is of potential commercial interest, the Contractor shall prepare and submit to the Management Committee with due diligence, within ninety (90) days of such notification, a proposed appraisal programme with a Work Programme and Budget to carry out an adequate and effective appraisal of such New Discovery designed to achieve both the following objectives:

(a) determine without delay, and, in any event, within the period specified in Article 10.5, whether such New Discovery should be declared a Commercial Discovery; and

(b) determine, with reasonable precision, the boundaries of the area to be delineated as a Field.

10.4 Consideration of Appraisal Programme by Management Committee

The proposed appraisal programme for a New Discovery shall be considered by the Management Committee within forty five (45) days after submission thereof pursuant to Article 10.3. The said appraisal programme, together with the Work Programme and Budget submitted by the Contractor, revised in accordance with any agreed amendments or additions thereto, approved by the Management Committee, shall be adopted as the Appraisal Programme and the Contractor shall promptly commence implementation thereof in accordance with the Approved Work Programme and Budget therefor.

10.5 Contractor to Make Recommendation Whether Discovery is Commercial

The Contractor shall, unless otherwise agreed, in respect of a New Discovery of Crude Oil, advise the Management Committee by notice in writing within a period of twenty four (24) months from the date on which the notice provided for in Article 10.1 was delivered, whether such New Discovery should be declared a Commercial Discovery or not. Such notice shall be accompanied by a report on the New Discovery setting forth all relevant technical and economic data as well as all evaluations, interpretations and analyses of such data and feasibility studies relating to the New Discovery prepared by or for the Contractor, with respect to the New Discovery. If the Contractor is of the opinion that Petroleum has been discovered in commercial quantities, it shall propose that the Management Committee declare the New Discovery as a Commercial Discovery based on the report submitted. In respect of a New Discovery of Gas, the provisions of Article 22 shall apply.

10.6 Management Committee to Determine if Discovery is Commercial

The Management Committee shall, within forty five (45) days of the date of the notice referred to in Article 10.5, consider the proposal of the Contractor and request any other additional information it may reasonably require so as to reach a decision on whether or not to declare the New Discovery as a Commercial Discovery. Such decision shall be made within the later of:

(a) sixty (60) days from the date of notice referred to in Article 10.5; or

(b) sixty (60) days of receipt of such other information as may be required under this Article 10.6.

10.7 Contractor to Submit Development Plan

If a New Discovery is declared a Commercial Discovery, within one hundred and twenty (120) days of the declaration of the New Discovery as a Commercial Discovery, the Contractor shall submit to the Management Committee a comprehensive plan for the development of the Commercial Discovery. Such plan shall contain detailed proposals by the Contractor for the construction, establishment and operation of all facilities and services for and incidental to the recovery, storage and transportation of the Petroleum from the Field to the Delivery Point together with all data and supporting information including but not limited to:

(a) Description of the nature and characteristic of the Reservoir, data, statistics, interpretations and conclusions on all aspects of the geology, reservoir evaluation, petroleum engineering factors, reservoir models, estimates of reserves in place, possible production magnitude, nature and ratio of Petroleum fluids and analysis of producible Petroleum;

(b) Outlines of the development project and/or alternative development projects, if any, describing the production facilities to be installed and the number of wells to be drilled under such development project and/or alternative development projects, if any;

(c) Estimate of the rate of production to be established and projection of the possible sustained rate of production in accordance with generally accepted international petroleum industry practice under such development project and/or alternative development projects, if any, which will ensure that the area does not suffer an excessive rate of decline of production or an excessive loss of reservoir pressure;

(d) estimates of Development Costs and Production Costs under such development project and/or alternative development projects, if any;

(e) Contractor's recommendations as to the particular project that it would prefer;

(f) anticipated adverse impact on the environment and measures to be taken for prevention or

minimisation thereof and for general protection of the environment in conduct of operations; and

(g) the information required in Articles 22.5(a) and 22.5(b).

10.8 Approval of Development Plan by Management Committee

Any proposed Development Plan submitted by the Contractor pursuant to Article 10.7 shall be approved or rejected by the Management Committee, within ninety (90) days of the date of submission of such Development Plan or within thirty (30) days after resubmission of the Development Plan containing such amendments and modifications as shall have been agreed by the Management Committee within the said ninety (90) day period. If such Development Plan has not been approved by the Management Committee within one hundred and twenty (120) days from the date of submission of the Development Plan, the Contractor shall have the right to submit such plan directly to the Government for approval, which approval shall not be unreasonably withheld. The said submission shall be approved or rejected within forty five (45) days of receipt.

10.9 Obligations Imposed on Contractor

An approved Development Plan shall commit the Contractor to the obligations stipulated in Articles 10.13 to 10.15.

10.10 Management Committee to Seek Necessary Government Approvals

The Management Committee shall seek such approvals from the Government as may be required, except where this Contract provides that the Contractor may seek such approvals directly.

10.11 Companies May Declare New Discovery to be Commercial

If ONGC considers a New Discovery to be non-commercial while the Companies consider that it is commercial and the Management Committee fails to declare the New Discovery as a Commercial Discovery within the time limit stipulated in Article 10.6 hereof, the Companies may declare the New Discovery as a Commercial Discovery and submit development and production plans in respect of the Discovery to the Government as per the provisions of Article 10.8 and after such plans have been approved by the Government, the Companies shall, acting solely, provide the entire Development Costs and undertake development of the said Oil Field. If, however, the said Oil Field turns out to be non-commercial, the entire Development Cost of the said Oil Field shall be borne solely by the Companies and

shall not be recoverable as Cost Petroleum from any other Field or Contract Area but shall be recoverable from Petroleum produced from such Oil Field. ONGC shall have no claim on the production from such Oil Field.

10.12 ONGC Rights Where Companies do not Declare Discovery to be Commercial

In the event that ONGC considers a New Discovery to be commercial but the Companies consider the same as non-commercial, ONGC shall give notice to the Companies to that effect and thereafter the Field relating to such New Discovery shall be excluded from the Contract Area and ONGC may proceed, acting solely, to develop that Field, providing the entire Development Cost. In that event, the Companies shall have no claim on the production from such Field and such Field shall be excluded from the Contract Area for all purposes.

10.13 Submission of Development Work Programmes and Budgets

Work Programmes and Budgets for Development and Production Operations shall be submitted to the Management Committee, through the Operating Committee, as soon as possible after the approval of a Development Plan by the Operating Committee and thereafter shall be approved by the Management Committee in accordance with Article 5.

10.14 Contractor to Provide Production Estimates

The Management Committee, when considering any Work Programme and Budget, may require the Contractor to prepare an estimate of potential production to be achieved through the implementation of the said programme and budget for each of the three (3) Years following the Year to which the Work Programme and Budget relate. If major changes in Year to Year estimates of potential production are required, these shall be based on concrete evidence necessitating such changes.

10.15 Determination of Programme Quantity

Not later than the fifteenth (15th) day of January each year, in respect of the Year immediately following, the Contractor shall determine the "Programme Quantity" with the approval of the Management Committee. The Programme Quantity for any Year shall be the maximum quantity of Petroleum based on Contractor's estimates, as approved by the Management Committee, which can be produced from a Field consistent with sound international petroleum industry practices and minimising unit production cost, taking into account the capacity of the producing Wells, gathering lines, separators, storage capacity and other production facilities available for use during the

relevant Year, as well as the transportation facilities up to the Delivery Point.

10.16 Revision of Development Plan

Proposed revisions of a Development Plan shall, if they constitute a material change to such Development Plan, be submitted to the Management Committee for approval, through the Operating Committee. Such proposed revisions shall be considered by the Management Committee within sixty (60) days after their submission and, to the extent same are approved, the Development Plan shall be deemed to be amended accordingly.

ARTICLE 11

DEVELOPMENT AND PRODUCTION FROM EXISTING DISCOVERIES AND SATELLITE FIELDS

11.1 Existing Discoveries

For the purposes of this Article 11, the following oil and gas fields shall be regarded as "Existing Discoveries:

a) the fault block containing the Ravva 10, 12, 35 and 36 wells and further defined as having been encountered in sandstones between 1556 and 1660 metres subsea in Ravva 10 and between 1668 and 1717 metres subsea in Ravva 12;

b) the fault block containing the Ravva 17, 27, 34 and 37 wells and further defined as having been encountered in sandstones between 1639 and 1712 metres subsea in Ravva 17 and between 1604 and 1686 metres subsea in Ravva 27; and

c) the fault block containing the Ravva 1, 7 and 9 wells and further defined as having been encountered in sandstones between 1602 and 1650 metres true vertical depth subsea in Ravva 7 and between 1583 and 1649 metres subsea in Ravva 9.

11.2 Ravva Development Plan

Appendix F to this Contract shall constitute the approved Development Plan for the Existing Discoveries (hereinafter referred to as "the Ravva Development Plan"). The Ravva Development Plan shall be deemed to have been approved by the Management Committee.

11.3 Revision of Ravva Development Plan

Any proposed revisions of the Ravva Development Plan shall, if they constitute a material change, be submitted to the Management Committee for approval together with any proposed consequential amendments to the Approved Work Programme and Budget, through the Operating Committee. Such proposed revisions shall be considered by the Management Committee within thirty (30) days after their submission and to the extent same are approved, the Ravva Development Plan together with the amendments to the relevant Work Programme and Budget shall be amended accordingly.

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11.4 Development of Satellite Fields

(a) The Ravva Development Plan provides for the drilling of Wells to explore for and/or appraise Petroleum which may exist in one or more hydrocarbon pools adjacent to the Existing Discoveries (such pool hereinafter referred to as "a Satellite Field").

(b) In the event that the drilling referred to in Article 11.4(a) discovers Petroleum or establishes that Petroleum may exist in commercial quantities, the Contractor shall comply with the provisions of Article 10.1 and Article 10.2.

(c) If Contractor is of the opinion that a Satellite Field should be immediately developed in conjunction with or as a part of the Ravva Development Plan, Contractor shall prepare a proposed Development Plan for submission to the Management Committee as soon as practicable, through the Operating Committee. Any such plan shall include the information required by Article 10.7.

(d) The Management Committee shall, within forty five (45) days of the date of submission of the proposed Development Plan pursuant to Article 11.4(c), consider the proposed Development Plan and request any other additional information it may reasonably require. The Management Committee shall approve or reject the proposed Development Plan (together with such modifications as may have been agreed between the Parties) within sixty (60) days of its submission to the Management Committee pursuant to Article 11.4(c).

(e) Upon approval of the proposed Development Plan (together with such modifications as may have been agreed between the Parties) such plan shall become an approved Development Plan in respect of the Satellite Field which is the subject of same and the proposed Work Programme and Budget submitted in accordance with Article 11.4(c) (together with such modifications as may have been agreed by the Parties) shall become an Approved Work Programme and Budget in respect of the Satellite Field.

ARTICLE 12

UNIT DEVELOPMENT

12.1 Government May Require Joint Development Plan

If a Reservoir in a Discovery Area is situated partly within the Contract Area and partly in an area in India over which other parties have a contract, licence or lease to conduct operations for the discovery of Petroleum and such Reservoir forms part of a New Discovery which would be a Commercial Discovery if developed together with that part of the reservoir which extends outside the Contract Area, the Government may, for securing the more effective recovery of Petroleum from such Reservoir, by notice in writing to the Contractor, require that the Contractor:

(a) collaborate and agree with such other parties on the joint development of the Reservoir;

(b) submit such agreement between the Contractor and such other parties to the Government for approval; and

(c) prepare a plan for such joint development of the said Reservoir, within one hundred and eighty (180) days of the approval of the agreement referred to in (b) above.

12.2 Government May Prepare Joint Development Plan

If no plan is submitted within the period specified in Article 12.1(c) or such longer period as the Parties may agree or, if such plan as submitted is not acceptable to the Government and the Parties cannot agree on amendments to the proposed joint development plan, the Government may cause to be prepared, at the expense of the Contractor and the other parties referred to in Article 12.1, a plan for such joint development consistent with generally accepted practices in the international petroleum industry which shall take into consideration any plans and presentations made by the Contractor and the aforementioned other parties.

12.3 Reference of Joint Development Plan to Sole Expert

If the Parties are unable to agree on the proposed plan for joint development, then any Party may refer the matter to a sole expert for final determination pursuant to Article 34, provided that the Contractor may in case of any disagreement on the issue of joint development or the proposed joint development plan, prepared in accordance with Article 12.2 or within sixty (60) days of determination by a sole expert, notify the Management

Committee and the Government that it elects to surrender its rights in the Reservoir in the Discovery Area in lieu of participation in a joint development of the Reservoir, in which event Contractor shall have no obligation to conduct any Petroleum Operations in relation to such Reservoir.

12.4 Implementation of Joint Development Plan

If a proposed joint development plan is agreed and adopted by the Parties, or adopted following determination by the sole expert, the plan as finally adopted shall be the approved joint development plan and the Contractor shall comply with the terms of the said Development Plan as if the Commercial Discovery is established.

ARTICLE 13

MEASUREMENT OF PETROLEUM

13.1 Methods and Appliances to be Used

The volume and quality of Petroleum produced and saved from a Field shall be measured by methods and appliances generally accepted and customarily used in good international petroleum industry practice and approved by the Management Committee.

13.2 Government May Inspect or Test Appliances

The Government may, at all reasonable times, inspect and test the appliances used for measuring the volume and determining the quality of Petroleum, provided that any such inspection or testing shall be carried out in such a manner so as not to unduly interfere with Petroleum Operations.

13.3 Matters to be Agreed Regarding Measurement and Testing

Before commencement of production in a Field, the Parties shall mutually agree on:

(a) methods to be employed for the measurement of volumes of Crude Oil production;

(b) the point or points at which Petroleum shall be measured and the respective shares allocated to the Parties in accordance with the terms of this Contract;

(c) the frequency of inspections and testing of measurement appliances and relevant procedures relating thereto; and

(d) the consequences of a determination of an error in measurement.

13.4 Contractor to Notify Government of Intention to Measure

The Contractor shall give the Government timely notice of its intention to conduct measuring operations or any agreed alteration for such operations and the Government shall, at its sole risk and expense, have the right to be present at and supervise, either directly or through authorised representatives, such operations.

ARTICLE 14

PROTECTION OF THE ENVIRONMENT

14.1 Contractor's General Obligations

The Government and the Contractor recognise that Petroleum Operations will cause some impact on the environment in the Contract Area and in the area of the existing onshore facilities. Accordingly, in performance of the Contract, the Contractor shall conduct its Petroleum Operations with due regard to concerns with respect to protection of the environment and conservation of natural resources. In the furtherance of any laws, regulations and rules of general application promulgated by the Government, the Contractor shall:

(a) employ generally accepted industry standards, including, as required, advanced techniques, practices and methods of operation then available for prevention of Environmental Damage in conducting its Petroleum Operations;

(b) take necessary and adequate steps to prevent Environmental Damage and, where some adverse impact on the environment is unavoidable, to minimize such damage and the consequential effects thereof on people and property; and

(c) adhere to the guidelines, limitations or restrictions, if any, imposed by any Environmental Clearance as applicable on the Effective Date and as such Environmental Clearance may be revised, expanded or replaced as a result of Contractor's application(s) duly submitted after the Effective Date, in relation to a change in the scope of activities for which Environmental Clearance is available as of the Effective Date.

14.2 Contractor to Remedy Environmental Damage

If the Contractor fails to substantially comply with the provisions of Article 14.1 or materially contravenes any relevant law, and such failure or contravention results in substantial Environmental Damage, the Contractor shall forthwith take all necessary and reasonable measures to remedy the failure and the effects thereof.

14.3 Discontinuance of Petroleum Operations

If the Government has, on reasonable grounds, reason to believe that any works or installations erected by the Contractor or any operations conducted by the Contractor are endangering or may endanger persons or any property

of any person, or are causing avoidable pollution, or are harming fauna and flora or the environment to a degree which is unlawful, the Government may, pursuant to applicable law, require the Contractor to take remedial measures within such reasonable period as may be determined by the Government and, if appropriate, repair such damage. The Government may, pursuant to applicable law, require the Contractor to discontinue Petroleum Operations in whole or in part until the Contractor has taken such action.

14.4 Environmental Impact Studies

Subject to the provisions of Article 14.5, the Contractor shall, within one hundred and twenty (120) days of the Effective Date, cause a person or persons with special knowledge on environmental matters, approved by the Government, to carry out an environmental impact study in order:

(a) to determine, at the time of the study, the prevailing situation relating to the environment, human beings and local communities, the wildlife and marine life in the Contract Area and in the adjoining or neighbouring areas; and

(b) to establish the likely effect on the environment, human beings and local communities, the wildlife and marine life in the Contract Area and in the adjoining or neighbouring areas in consequence of the relevant phase of Petroleum Operations to be conducted under this Contract.

14.5 Approval of Environmental Studies Regarding Existing Discoveries

The Parties agree that the requirements of Article 14.4 have been satisfied in relation to the activities contemplated by the Ravva Development Plan by the following documents:

a) "Environmental impact assessment of proposed development at RAVVA Offshore oil field in Godavari Basin and onshore terminal facilities at Surasaniyanam by NEERI, January, 1991."

b) "Contingency plan for disaster management RAVVA offshore development plan (3 volumes), December, 1991."

prepared by or on behalf of ONGC, to the extent that such activities fall within the scope of the activities referred to in the said documents.

14.6 Contractor's Conduct of Operations and Obligations Regarding Subcontractors

The Contractor shall ensure that:

(a) Petroleum Operations are conducted in an environmentally acceptable and safe manner consistent with good international petroleum industry practice and that such Petroleum Operations are properly monitored;

(b) the pertinent completed environmental impact studies are made available to its employees and Subcontractors to develop adequate and proper awareness of the measures and methods of environmental protection to be used in carrying out Petroleum Operations; and

(c) the contracts entered into between the Contractor and its Subcontractors relating to its Petroleum Operations shall include the provision stipulated in paragraph (a) herein and any established measures and methods for the implementation of the Contractor's obligations in relation to the environment under this Contract.

14.7 Submission of Contingency Plans and Emergency Operations

(a) The Contractor shall, prior to conducting any drilling activities, prepare and submit for review by the Government contingency plans for dealing with oil spills, fires, accidents and emergencies, designed to achieve rapid and effective emergency response. The plans referred to above shall be discussed with the Government and concerns expressed shall be taken into account.

(b) In the event of an emergency, accident, oil spill or fire arising from Petroleum Operations affecting the environment, the Contractor shall forthwith notify the Government and shall promptly implement the relevant contingency plan and perform such Site Restoration as may be necessary.

(c) In the event of any other emergency or accident arising from the Petroleum Operations affecting the environment, the Contractor shall take such action as may be prudent and necessary in accordance with good international petroleum industry practice in such circumstances.

14.8 Government Action

In the event that the Contractor fails to take necessary action to comply with any of the terms contained in Article 14.6 within a reasonable period specified by the Government, the Government, after giving the Contractor reasonable notice in the circumstances, may take any action which may be necessary to ensure compliance with such terms and to recover from the Contractor, immediately after having taken such action, all costs and expenditures incurred in connection with such action together with such interest as may be determined in accordance with Section 1.7 of Appendix C of this Contract.

14.9 Contractor's Abandonment Obligations

On expiry or termination of this Contract or relinquishment of part of the Contract Area, the Contractor shall:

(a) subject to Article 28, remove all equipment and installations from the relinquished area or former Contract Area in a manner agreed with the Government pursuant to an abandonment plan; and

(b) perform all necessary Site Restoration activities in accordance with good international petroleum industry practice and take all other action necessary to prevent hazards to human life or to the property of others or the environment.

14.10 Reference to Government Includes Reference to State Government

In this Article, a reference to Government includes the State Government, wherever applicable.

14.11 Costs to be Cost Recoverable

Any and all costs incurred by Contractor pursuant to this Article shall be cost recoverable including, but not limited to, sinking funds established for abandonment.

14.12 Contractor Not Liable for Prior Environmental Damage; Contractor's Liability for Environmental Damage

The responsibility of the Contractor for the environment hereunder shall be limited to damage to the environment which:

(a) occurs after the Effective Date; and

(b) results from an act or omission of Contractor in violation of existing law.

ARTICLE 15

RECOVERY OF COSTS FOR OIL AND GAS

15.1 Contractor Entitled to Recover Contract Costs and Past Costs

The Contractor shall be entitled to 100% of the total volumes of Petroleum produced and saved from the Contract Area in accordance with the provisions of this Article until the value of such Petroleum entitlement, after deduction of all applicable levies including all Royalty and Cess paid in respect of Petroleum produced and saved from the Contract Area, is equal to Contract Costs together with Past Costs. For the avoidance of doubt, it is agreed that Past Costs shall not exceed the sum of fifty five million US Dollars ($US55 million) for the purposes of cost recovery.

15.2 Recovery of Exploration Costs up to Date of Commercial Production

Exploration Costs (if any) incurred by the Contractor in the Contract Area up to the date of Commercial Production shall be aggregated and the Contractor shall be entitled to recover the aggregate of such Exploration Costs out of the Cost Petroleum at the rate of one hundred percent (100%) per annum of such Exploration Costs beginning from the date of such Commercial Production, as provided in Article 15.4.

15.3 Recovery of Exploration Costs After Date of Commercial Production

The Contractor shall be entitled to recover out of the Cost Petroleum the Exploration Costs which it has incurred in the Contract Area in any Year after the date of Commercial Production at the rate of one hundred percent (100%) per annum of such Exploration Costs beginning from the date such Exploration Costs are incurred as provided in Article 15.4.

15.4 Exploration Costs not Allowable For Recovery Against Other Contract Areas

The Contractor shall be entitled to recover Exploration Costs as provided in Articles 15.2 and 15.3 in proportion to the values of the quantity of Petroleum produced and saved from the Contract Area as reduced by the Production Costs in the Contract Area in the relevant Year, provided that such Exploration Costs once recovered shall not be allowable for recovery against any other Contract Area.

15.5 Recovery of Development Costs and 5% Cost Cap

(a) Development Costs incurred by the Contractor in the Contract Area shall be aggregated, and the Contractor shall be entitled to recover out of Cost Petroleum the aggregate of such Development Costs at the rate of one hundred percent (100%) per annum.

(b) Notwithstanding the provisions of Article 15.5(a) and subject to the remaining provisions of this Article 15.5, the Contractor shall not, for the purposes only of determining the volume of Petroleum to which Contractor shall be entitled under Article 15.1 as Cost Petroleum, claim as Contract Costs Contractor's Development Costs incurred after the Effective Date in connection with Development Operations under the Ravva Development Plan which exceed Contractor's Base Development Costs (as hereinafter defined) by more than five percent (5%).

(c) For the purposes of this Article 15.5, "Contractor's Base Development Costs" means costs incurred after the Effective Date relating to the construction and/or establishment of such facilities as are necessary to produce, process, store and transport Petroleum from within the Existing Discoveries, in order to enable Crude Oil production of 35,000 BOPD in accordance with the Ravva Development Plan plus such costs as are allowed pursuant to Section 3.3 of the Accounting Procedure. Such costs shall include, but not be limited to, costs incurred in relation to the following facilities and matters in connection therewith, such as:

(i) offshore tanker loading facilities for tankers up to 120,000 DWT;

(ii) wellhead platforms capable of supporting up to a total of 24 Development Wells;

(iii) flowlines necessary to transport well fluids ashore for processing;

(iv) process facilities onshore for processing up to 40,000 Barrels of fluid per day;

(v) storage facilities with a nominal capacity of 500,000 Barrels;

(vi) facilities to allow injection of water into the reservoirs for the purposes of reservoir pressure maintenance;

(vii) construction of an onshore supply base to support production operations;

(viii) environmental studies;

(ix) geophysical, geological and petroleum engineering studies;

(x) Reprocessing of 3-D seismic;

(xi) the drilling of nineteen (19) Development Wells and two (2) Gas production Wells;

(xii) facilities for developing, transporting and processing NANG;

(xiii) Project insurance; and

(xiv) Project management.

The Parties agree that for the purposes of this Article 15.5 the Contractor's Base Development Costs shall be the sum of US$188.98 million (as indicated in the August 1993 Addendum to the Ravva Development Plan).

(d) The Parties acknowledge that the amount representing Contractor's Base Development Costs has been agreed by Contractor on the basis of the following assumptions and/or factors and/or information:

(i) Costs relating to Site Restoration and exploration or appraisal drilling have not been included in the calculation of the said amount;

(ii) the said amount does not include any costs for the development of any Satellite Fields;

(iii) the Contractor being able to obtain all necessary approvals (including Government and State Government approvals) to enable Contractor to carry out the Development Operations contemplated by the Ravva Development Plan in accordance with the timing set out in such plan;

(iv) the data relating to the Contract Area provided by ONGC from time to time prior to the Effective Date inclusive of the data package pertaining to the Contract Area prepared by ONGC and made available for inspection and purchase by the Companies pursuant to the Government's "Notice Inviting Offers for Joint Ventures to Develop Medium - Sized Oil and Gas Field in India, 1992";

(v) international market conditions prevailing as at August 1993 relating to the availability and cost of materials and services in the international petroleum industry; and

(vi) the range of physical reservoir characteristics not being materially different from the ranges for such characteristics on which the Ravva Development Plan has been based.

(e) Having regard, inter alia, to the matters referred to in Article 15.5(d), the Parties agree as follows:

(i) costs relating to Site Restoration and exploration and appraisal drilling shall not be subject to the limit on Contractor's Development Costs as provided in Article 15.5(b);

(ii) the costs of developing the reserves and/or potential reserves and/or Satellite Fields referred to in Article 15.5(d)(ii) shall not be subject to the limit on Contractor's Development Costs as provided in Article 15.5(b), notwithstanding that the development of such reserves and/or potential reserves and/or Satellite Fields may include shared flowlines, injection lines, gas-lift lines and other facilities with those constructed as part of the Ravva Development Plan;

(iii) in the event that the Contractor's Base Development Costs are exceeded by more than five percent (5%) as a result of:

(aa) delays in carrying out the Development Operations referred

to in Article 15.5(d)(iii) due to a delay in obtaining any necessary approval;

(bb) material changes to the Ravva Development Plan necessitated by Contractor's review of data provided to the Companies by the Government and/or ONGC after the Effective Date pursuant to Article 8.1(a)(iv), where the Companies are able to establish that had such data been available prior to the Effective Date then the Companies, acting reasonably, would have included such changes in the Ravva Development Plan;

(cc) a material change to the international market conditions referred to in Article 15.5(d)(v);

(dd) the range of physical reservoir characteristics being materially different from the ranges for such characteristics on which the Ravva Development Plan has been based;

(ee) a variation to the Ravva Development Plan approved by the Management Committee; or

(ff) an event of force majeure as provided in Article 32;

then the Management Committee shall, at the request of the Operator, in a meeting convened under Article 6.7, promptly consider what, if any, increase should be made to the Contractor's Base Development Costs to fairly reflect the circumstances in question PROVIDED THAT in the case of delays referred to in Article 15.5(e)(iii)(aa) the Management Committee shall not be obliged to consider any increase where such delay has been caused by the Contractor's failure to act in a diligent manner.

(f) In the event that:

(i) there is any dispute between the Parties whether or to what extent a circumstance referred to in Article 15.5(e)(iii) has

arisen or resulted in the Contractor's Base Development Costs being exceeded by more than five percent (5%); or

(ii) the Management Committee is unable to agree whether an increase should be made to the Contractor's Base Development Costs or is unable to agree on the amount of any such increase;

then, at any time after thirty (30) days from the date of the Management Committee meeting referred to in Article 15.5(e)(iii), any Party shall be at liberty to refer the matter to a sole expert for decision in accordance with the provisions of Article 34.2.

15.6 Recovery of Contract Costs

The Contractor shall be entitled to recover in full during any Year the Contract Costs incurred in the Contract Area in that Year out of the Cost Petroleum. If during any Year the Cost Petroleum is not sufficient to enable the Contractor to recover in full the Contract Costs due for recovery in that Year in accordance with the provisions of Articles 15.1 to 15.5 then, subject to the provisions of Article 15.1:

(a) recovery shall first be made of the Production Costs; and

(b) recovery shall next be made of the Exploration Costs; and

(c) recovery shall then be made of the Development Costs.

The unrecovered portions of Contract Costs shall be carried forward to the following Year and the Contractor shall be entitled to recover such costs in such Year or the subsequent Years as if such costs were due for recovery in that Year, or the succeeding Years, until the unrecovered costs have been fully recovered out of Cost Petroleum from the Contract Area.

15.7 Conversion to Production Equivalent Units

For the purposes of this Article, as well as Article 16, costs, receipts and income shall be converted into production unit equivalents, and vice versa, using the relevant prices established pursuant to Article 20 for Crude Oil and Article 22 for Natural Gas.

15.8 Provisional and Final Determinations of Cost Petroleum

Pending completion of the calculations required to establish definitively the Contractor's entitlement to Cost Petroleum in any Year, the Contractor shall take delivery, provisionally, of volumes of Crude Oil or Natural Gas representing its estimated Cost Petroleum entitlement calculated with reference to estimated production quantities, costs and prices for the Contract Area as established by the Contractor and approved by the Management Committee. Such provisional determination of Cost Petroleum shall be made every Quarter on an accumulative basis. Within sixty (60) days of the end of each Year, a final calculation of the Contractor's entitlement to Cost Petroleum, based on actual production quantities, costs and prices for the entire Year, shall be undertaken and any necessary adjustments to the Cost Petroleum entitlement shall be agreed upon between the Parties and made as soon as practicable thereafter.

ARTICLE 16

PRODUCTION SHARING OF PETROLEUM BETWEEN CONTRACTOR AND GOVERNMENT

16.1 Profit Petroleum Determined by PTRR Method

(a) The Contractor and the Government shall share in the Profit Petroleum from the Contract Area in accordance with the provisions of this Article.

(b) The share of Profit Petroleum, in any Year, shall be calculated for the Contract Area on the basis of the Post Tax Rate of Return actually achieved by the Companies at the end of the preceding Year for the Contract Area as provided in Appendix D.

16.2 Profit Petroleum Split Between Government and Contractor

(a) When the Post Tax Rate of Return of the Companies at the end of any Year in respect of the Contract Area is more than zero percent (0%) but less than fifteen percent (15%), the Government shall be entitled to take and receive ten percent (10 %) and the Contractor shall be entitled to take and receive ninety percent (90%) of the total Profit Petroleum from the Contract Area with effect from the start of the succeeding Year.

(b) When the Post Tax Rate of Return of the Companies at the end of any Year in respect of the Contract Area is equal to or is more than fifteen percent (15%) but is less than twenty percent (20%), the Government shall be entitled to take and receive fifteen percent (15%) and the Contractor shall be entitled to take and receive eighty five percent (85%) of the total Profit Petroleum from the Contract Area with effect from the start of the succeeding Year.

(c) When the Post Tax Rate of Return of the Companies at the end of any Year in respect of the Contract Area is equal to or more than twenty percent (20%) but is less than twenty five percent (25%), the Government shall be entitled to take and receive twenty percent (20%) and the Contractor shall be entitled to take and receive eighty percent (80%) of the total Profit Petroleum from the Contract Area with effect from the start of the succeeding Year.

(d) When the Post Tax Rate of Return of the Companies at the end of any Year in respect of the Contract Area is equal to or more than twenty five percent (25%) but is less than thirty percent (30%) the

Government shall be entitled to take and receive twenty five percent (25%) and the Contractor shall be entitled to take and receive seventy five percent (75%) of the total Profit Petroleum from the Contract Area with effect from the start of the succeeding Year.

(e) When the Post Tax Rate of Return of the Companies at the end of any Year in respect of the Contract Area is equal to or more than thirty percent (30%), but is less than forty percent (40%), the Government shall be entitled to take and receive thirty five percent (35%) and the Contractor shall be entitled to take and receive sixty five percent (65%) of the total Profit Petroleum from the Contract Area with effect from the start of the succeeding Year.

(f) When the Post Tax Rate of Return of the Companies at the end of any Year in respect of the Contract Area is equal to or more than forty percent (40%), the Government shall be entitled to take and receive sixty percent (60%) and the Contractor shall be entitled to take and receive forty percent (40%) of the total Profit Petroleum from the Contract Area with effect from the start of the succeeding Year.

16.3 PTRR Level Not to Revert to Lower Level

For the avoidance of doubt, it is hereby stated that once the Companies' Post Tax Rate of Return has increased so as to trigger, in any Year, a higher percentage of Profit Petroleum sharing for the Government (and a lower percentage for the Contractor) than that existing before the date of such increase, the Parties shall be entitled to share in the total volume of Profit Petroleum in the proportions specified in the relevant Articles above in respect of the higher levels of Post Tax Rate of Return and shall not be entitled to receive any Profit Petroleum shares in respect of the lower levels of profitability.

16.4 Calculation of PTRR in Accordance with Appendix D

The value of the Companies' Post Tax Rate of Return at the end of any Year in respect of the Contract Area shall be calculated in the manner provided for, and on the basis of the net cash flows specified, in Appendix D to this Contract. However, the volume of Profit Petroleum to be shared between the Government and the Contractor shall be determined for each Quarter on an accumulative basis. Pending finalization of accounts, delivery of Profit Petroleum shall be taken by the Government and the Contractor on the basis of provisional estimated figures of Contract Costs,

production, prices, receipts, income and any other income or allowable deductions and on the basis of the value of the Post Tax Rate of Return achieved at the end of the preceding Year. All such provisional estimates shall be approved by the Management Committee. When it is necessary to convert monetary units into physical units of production equivalents or vice versa, the price or prices determined pursuant to Articles 20 and 22 for Crude Oil and Natural Gas respectively shall be used. Within sixty (60) days of the end of each Year, a final calculation of Profit Petroleum based on actual costs, quantities, prices and income for the entire Year shall be undertaken and any necessary adjustments to the sharing of Petroleum shall be agreed upon between the Government and the Contractor and made as soon as is practicable thereafter.

ARTICLE 17

TAXES, ROYALTIES, RENTALS, CUSTOMS DUTIES STAMP DUTY, SALES TAX, ETC.

17.1 Indian Fiscal Legislation to Apply to Operations

All the Parties and the operations under this Contract shall be subject to all laws including fiscal legislation in India except where they are exempted wholly or partly from the application of the provisions of a particular law or as otherwise provided in this Contract.

17.2 Royalty and Cess

(a) The Contractor shall be liable for payment of Royalty and Cess at the rate of Rs 481 per tonne and Rs 900 per tonne of Crude Oil respectively, Royalty at the rate of 10% of wellhead value of Gas, and other payments required under the Lease. The Companies comprising Contractor shall not be liable to the Government for payment of Royalty or Cess in excess of the abovestated rates, or Cess as may be levied in respect of Gas, the costs of which shall be borne by the Government.

(b) All payments (except corporate income tax) made by the Contractor pursuant to this Article 17 and all other expenses which are in the nature of expenses provided in this Article 17, including but not limited to any duties, levies, fees, charges and any other assessments levied by any government or taxing authority in connection with the Contractor's activities under the Contract and paid by the Contractor shall be cost recoverable as Contract Costs.

17.3 Petroleum Used in Operations, Unavoidably Lost or Flared

The Contractor shall not be obliged to pay Royalty or Cess in respect of Petroleum that is used in Petroleum Operations, unavoidably lost or flared.

17.4 Basis of Computation of Income Tax

The profits and gains of a Company from the business of Petroleum Operations shall, for the purpose of levy of income tax under the Income-Tax Act, 1961, be computed on the basis of the value, determined in accordance with Article 20, of its Participating Interest share of Crude Oil produced and saved and sold, or otherwise disposed of, from the Contract Area and from any revenue realised on the sale or disposal of Associated or Non Associated Natural Gas referred to in Article 22 as well as any

other gains or receipts from Petroleum Operations as reduced by the allowable deductions.

17.5 Allowances For Income Tax Purposes

(a) For the purpose of computing profits or gains of the business consisting of prospecting for or extraction or production of Petroleum, there shall be made in lieu of the allowances admissible under the Income Tax Act, 1961, such allowances as are specified in this Contract (which shall be laid on the Table of each House of Parliament in the session immediately following the execution of this Contract) pursuant to Section 42 in relation to:

(i) expenditure by way of infructuous or abortive exploration expenses in respect of any area surrendered prior to the beginning of commercial production; and

(ii) after the beginning of commercial production, expenditure incurred, whether before or after such commercial production, in respect of drilling or exploration activities or services or in respect of physical assets used in that connection.

(b) Payments made by the Companies pursuant to Article 18 shall be deductible for income tax purposes in the Year in which such payments are made by the Companies, as permissible under Section 42 of the Income Tax Act, 1961.

(c) In respect of matters not covered by the allowances specified above, deduction shall be allowed in accordance with the other provisions of the Income Tax Act, 1961, and the rules framed thereunder.

17.6 Depreciation Claims

In respect of assets acquired by ONGC pursuant to the provisions of Article 28.4, where tax depreciation has not been fully claimed in accordance with section 32 of the Income Tax Act,1961, each Party comprising Contractor shall be entitled to claim the balance depreciation in proportion to its Participating Interest PROVIDED THAT under no circumstances shall depreciation of such assets exceed one hundred percent (100%).

17.7 Deduction of Exploration Costs For Income Tax Purposes

A Company shall be entitled, for income tax purposes only, to deduct, at the rate of one hundred percent (100%), all of its unsuccessful exploration costs incurred in contract areas covered by other contracts from the aggregate value of Petroleum allocable to the Company from any Fields in the Contract Area.

17.8 Companies Not Liable For Taxes (Except Income Tax) or Customs Duties

Except as otherwise provided in this Article, the Government covenants to the Companies that Companies shall not be liable to the Government for payment of:

(a) any taxes calculated by reference to income from or sales of Petroleum; or

(b) any customs or excise duties, export duties or any other statutory charges on the import or re-export of machinery, plant, equipment, materials or supplies imported by or on behalf of Contractor or its Subcontractors solely and exclusively for use in Petroleum Operations.

17.9 Contractor to be Entitled to Benefit of Laws Reducing Economic Burdens

Contractor shall be entitled to and receive the benefit of any amendment to or repeal of a law, rule or regulation which relieves any economic burden placed upon the Contractor.

17.10 Government to be Responsible For Stamp Duty

Any stamp duty payable on this Contract shall be the responsibility of the Government.

17.11 Government Responsible For Sales Tax on Sales to Government

The Government covenants to the Companies that the Government (or its nominee) shall be responsible for payment of any sales tax (whether payable to Government or to a State Government) payable on sales of Petroleum to the Government pursuant to the provisions of Articles 19 or 22.

17.12 Changes to Indian Laws

If any change in or to any Indian law, rule or regulation dealing with income tax or other corporate tax, export/import tax, excise, customs duty, or tax imposed on Petroleum or dependent upon the value of

Petroleum (including Royalty and Cess), results in an adverse change to the expected economic benefits accruing to any of the Parties after the Effective Date of the Contract, the Parties shall consult promptly in good faith to make necessary revisions and adjustments to the Contract in order to maintain such expected economic benefits to each of the Parties provided that the expected economic benefits to the Parties shall not be reduced as a result of the operation of this Article.

ARTICLE 18

PAYMENTS

18.1 Payments

The Companies shall pay to ONGC such consideration as hereinafter mentioned in this Article to carry out exploration and drilling activities in the Contract Area:

(a) the sum of six million two hundred and fifty thousand US Dollars (US$ 6,250,000) within fifteen (15) days of the Effective Date and a further sum of six million two hundred and fifty thousand US Dollars (US$ 6,250,000) one (1) calendar year after the Effective Date.

(b) sums linked to production levels, subject to Article 18.1(c), as set out in Column 2 of the following table, within fifteen (15) days after production of Crude Oil produced after the Effective Date reaches the levels set out opposite such sums in Column 1, as production payments:

Column 1 Cumulative Production (Millions of Barrels-MMBbl)	Column 2 Incremental Production Payment (US Dollars)
25 MMBbl	$ 9,000,000
50 MMBbl	$ 9,000,000
75 MMBbl	$ 9,000,000
80 MMBbl	$ 1,800,000
85 MMBbl	$ 1,800,000
90 MMBbl	$ 1,800,000
95 MMBbl	$ 1,800,000
100 MMBbl	$ 1,800,000

After cumulative production of Crude Oil reaches 100 million Barrels, a production payment shall be payable to ONGC at a rate to be agreed by the Parties but which will not exceed one million eight hundred thousand US Dollars (US$ 1,800,000) per five (5) million Barrel tranche.

(c) Payments shall not be required to be made under Article 18.1(b) until such time or times as the value of Companies' share of Profit Petroleum, less notional income tax as referred to in paragraph 2(vii) of Appendix D, is equal to or exceeds the payments referred to in Article

18.1(a) plus the respective production payments payable under Article 18.1(b).

18.2 Government Entitlement to Additional Production

The Parties comprising Contractor agree that they will assign to the Government, out of production, during each of the Contract Years after the Effective Date set out in Column 1 of the following table, that number of Barrels of Crude Oil as is set out opposite the relevant Contract Year in Column 2, in proportion to their Participating Interests:

Column 1 Contract Year following Effective Date	Column 2 Barrels of Crude Oil
Year 3	200,000
Year 4	150,000
Year 5	100,000
Year 6	50,000

The Companies and ONGC shall use all reasonable endeavours to ensure that, as far as is practicable, assignments of Crude Oil to the Government pursuant to this Article 18.2 will be evenly distributed throughout each year.

18.3 Payments not Cost Recoverable

The payments referred to in Article 18.1 shall in no event be recoverable as Contract Costs by Companies and shall not be creditable against ONGC's Past Costs.

18.4 ONGC and Government not Entitled to Production Payments on Gas

Neither ONGC nor the Government shall be entitled to any production payments in relation to the production of Gas.

ARTICLE 19

DOMESTIC SUPPLY, SALE, DISPOSAL AND EXPORT OF CRUDE OIL, PRODUCTION FORECASTS, RIGHT TO SEPARATELY LIFT, LIFTING PROCEDURE

19.1 Contractor to Offer Crude Oil For Sale Within India

Until such time as the total Crude Oil from all Petroleum production activities in India meets the total national demand as determined by the Government, each Party comprising the Contractor (hereinafter in this Article 19 referred to as "Contractor Party" or, collectively, as "Contractor Parties") shall be required to offer for sale its Participating Interest share of Crude Oil for consumption within India in order to assist in satisfying the national demand.

19.2 Crude Oil to be Offered to Government

(a) Subject to Article 19.3, Crude Oil shall be offered for sale to the Government, at the price determined pursuant to Article 20 for sales to the Government, and the Government shall have the option to purchase the whole or any portion thereof offered at the said price.

(b) The aforementioned offer shall be made by a Contractor Party, in writing, at least three (3) months preceding the Year in which the sale is to be made, specifying the estimated quantities and grade of Crude Oil being offered (based upon estimates which shall be adjusted within ninety (90) days of the end of each Year on the basis of actual quantities produced and saved). The Government shall use its best endeavours to determine whether or not to exercise its said option as soon as possible but in any event the Government shall exercise its said option to purchase, in writing, not later than one (1) month prior to the commencement of the Year in respect of which the sale is to be made, specifying the quantity and grade of Crude Oil which it elects to take in the ensuing Year. Failure by the Government to give such notice within the period specified shall be conclusively deemed an election not to take all of the Crude Oil offered in the ensuing Year.

19.3 Sales Other Than to Government

Each Contractor Party shall be free to sell privately in India all or part of its Participating Interest share of Crude Oil to which it is entitled under Articles 15 and 16 upon:

(a) the introduction by the Government of a policy allowing for a deregulated market in Crude Oil sales;

(b) Crude Oil produced in India being permitted to be sold and/or supplied to non-Government users (such as, but not limited to, non-Government refineries); or

(c) the Government electing not to exercise its option to purchase Crude Oil pursuant to Article 19.2(b).

19.4 Contractor Parties' Right to Export

(a) The Contracotr Parties shall be entitled to freely lift and export any Crude Oil where the Government has elected not to exercise its rights to purchase pursuant to Article 19.2(b).

(b) Where:

(i) the Government (or its nominee, as defined in Article 20.10) is unable to take Crude pursuant to Article 19.10 by reasons of force majeure (as defined in Article 32); or

(ii) the Government is in default of its payment obligations under Article 19.7 for a period of five (5) Business Days or more;

then the Contractor Parties shall be entitled to sell Crude Oil to which the Government would otherwise be entitled privately in India PROVIDED THAT where such sales cannot be arranged in a timely fashion on terms and conditions reasonably acceptable to the Contractor Parties then the Contractor Parties shall be entitled to freely lift and export such Crude Oil subject to Government's generally applicable destination restrictions to countries with which the Government, for policy reasons, has severed or restricted trade.

19.5 Swap Arrangements

A contractor Party may, with the prior consent of Government, where the Contractor Party establishes to the reasonable satisfaction of the Government that the purposes and objectives of Article 19.1 are being satisfied, in relation to part or all of its Participating Interest share of Crude Oil:-

(a) swap by the export of such Crude Oil and import into India of a hydrocarbon of an agreed nature to the same value; and/or

(b) swap by the sale into India of such Crude Oil and the export of a hydrocarbon of an agreed nature to the same value; and/or

(c) swap by the sale to the Government of such Crude Oil and the export of a hydrocarbon where produced in India or the granting for use overseas where produced outside India of a hydrocarbon of an agreed nature to the same value.

19.6 Attainment of Self-Sufficiency

If during any Year, India attains Self-sufficiency, the Government shall promptly thereafter, but in no event later than the end of the first Calendar Quarter of the following Year, so advise the Contractor Parties by written notice. In such event, as from the end of the second Calendar Quarter of the following Year, or such earlier date as the Parties may mutually agree, a Contractor Party shall have the right to lift and export its Participating Interest share of Crude Oil until such time, if any, as Self-sufficiency shall have ceased to exist. If Self-sufficiency ceases to exist during a Year, the Government shall promptly notify the Contractor Parties in writing. In such event, the Contractor Parties shall, until Self-sufficiency is re-established, comply with the provisions of Article 19.2 except as such Article may be modified by Article 19.5.

19.7 Payment by Government

All payments in respect of sales to the Government pursuant to provisions of this Article 19 shall be made by the Government within the period for credit applicable in the calculation of the price pursuant to Article 20. If no time frame for credit is applicable in such calculation, payment shall be made within thirty (30) days from the date of the bill of lading/road transport challan in respect of each such sale. Contracting Party shall submit an invoice to the Government within fifteen (15) days from the date of the bill of lading/road transport challan date. Payment by the Government for each such sale by each of the Contractor Parties that is a Foreign Company shall be made in United States Dollars or any other convertible currency acceptable to the Government and the respective Contractor Party, by wire transfer, to the credit of such Contractor Party's account with a bank within or outside of India, as designated by such Contractor Party. All amounts unpaid by the Government by the due date shall, from the due date, bear interest calculated on a day to day basis at LIBOR plus two (2) percentage points from the due date until paid.

19.8 Production Forecasts

No later than sixty (60) days prior to the commencement of production in a Field (or Fields, where production is from more than one Field), and thereafter no less than sixty (60) days before the commencement of each Year, the Contractor shall cause to be prepared and submitted to the Parties a production forecast setting out the total quantity of Crude Oil that it estimates can be produced from a Field (or Fields) during the succeeding Year, based on a maximum efficient rate of recovery of Crude Oil from that Field (or those Fields) in accordance with good international petroleum industry practice. No later than thirty (30) days prior to the commencement of each Quarter, the Contractor shall advise its estimate of production for the succeeding Quarter and shall endeavour to produce the forecast quantity for each Quarter.

19.9 Contractor's Rights to Separately Take

Each Contractor Party shall, throughout the term of this Contract, have the right to separately take in kind and dispose of all its share of Cost Petroleum and Profit Petroleum and shall have the obligation to lift the said Cost Petroleum and Profit Petroleum on a current basis and in such quantities so as not to cause a restriction of production or inconvenience to the other Parties.

19.10 Government's Right to Separately Take.

The Government (or its nominee) shall, throughout the term of this Contract, have the right to separately take in kind and dispose of such portion of the Contracting Parties' share of Crude Oil as is purchased by the Government (or its nominee) pursuant to Article 19 and its share of Profit Petroleum, and shall have the obligation to take all of the said Oil on a current basis and in such quantities so as not to cause a restriction of production or inconvenience to the other Parties.

19.11 Lifting Procedure

For the purpose of implementing the provisions of Articles 19.9 and 19.10, a Crude Oil lifting procedure shall be agreed upon by the Parties no later than three (3) months after the Effective Date. Such lifting procedure shall include, but not necessarily be limited to:

(a) a procedure for notification by the Operator to the Government, and to each Contractor Party, of projected Crude Oil production;

(b) a procedure for notification by the Government, and by each Contractor Party, to the Operator, of its expected offtake and the consequences of inability or failure to offtake; and

(c) such other provisions as are normally found in lifting agreements in the international petroleum industry.

ARTICLE 20

VALUATION OF PETROLEUM

20.1 Value to be Based on Price

For the purpose of this Contract, the value of Crude Oil and Natural Gas shall be based on the price determined as provided herein.

20.2 Crude Oil Price to be on FOB Basis

A price for Crude Oil shall be determined for each Month or such other period as the Parties may agree (hereinafter referred to as "the Delivery Period") in terms of United States Dollars per Barrel, FOB Delivery Point for Crude Oil produced and sold or otherwise disposed of from each Field, for each Delivery Period, in accordance with the appropriate basis for that type of sale or disposal specified below.

20.3 Arms Length Sales

(a) In the event that some or all of the total sales of Crude Oil of a Party comprising Contractor (hereinafter in this Article 20 referred to as "Contractor Party") during a Delivery Period are made in Arms Length Sales, all sales so made shall be valued at the weighted average of the prices actually received by a Contractor Party, calculated by dividing the total receipts from all such sales FOB the Delivery Point by the total number of Barrels of the Crude Oil sold in such sales.

(b) In the event that a portion of such Arms Length Sales are made on a basis other than an FOB basis as herein specified, the said portion shall be valued at prices equivalent to the prices FOB the Delivery Point for such sales determined by deducting all costs (such as transportation, demurrage, loss of Crude Oil in transit and similar costs) incurred downstream of the Delivery Point, and the prices so determined shall be deemed to be the actual prices received for the purpose of calculation of the weighted average of the prices for all Arms Length Sales for the Delivery Period.

(c) Each Contractor Party shall separately submit to the designated nominee of the Government, within fifteen (15) days of the end of each Delivery Period, a report containing the actual prices obtained in their respective Arms Length Sales of any Crude Oil. Such reports shall distinguish

between term sales and spot sales and itemize volumes, customers, prices received and credit terms, and a Contractor Party shall allow the designated nominee of the Government to examine the relevant sales contracts.

20.4 Determination of Price For Sales of Crude Oil to Government

(a) In the event that some or all of a Contractor Party's total sales of Crude Oil during a Delivery Period are made to the Government or its nominee, the price of all sales so made shall, unless otherwise agreed between the Parties, be determined on the basis of either the FOB selling price per Barrel of one or more crude oils which, at the time of calculation, are being freely and actively traded in the international market and are similar in characteristics and quality to the Crude Oil in respect of which the price is being determined, such FOB selling price to be ascertained from Platt's Crude Oil Market Wire daily publication ("Platt's"), or the spot market for the same crude oils ascertained in the same manner, whichever price, in the opinion of the Parties, more truly reflects the current value of such crude oils. For any Delivery Period in which sales take place, the price shall be the arithmetic average price per Barrel determined by calculating the average for such Delivery Period of the mean of the high and low FOB or spot prices for each day of the crude oils selected for comparison adjusted for differences in the Crude Oil and the crude oils being compared for quality, transportation costs, insurance costs (where appropriate), delivery time, quantity, payment terms, the market area into which the Crude Oil is being sold, other contract terms to the extent known and other relevant factors. In determining the quality of a crude oil, account shall be taken of all relevant characteristics including but not limited to gravity, sulphur and metal content, pour point and product yield. In the event that Platt's ceases to be published or is not published for a period of thirty (30) consecutive days, the Parties shall agree on an alternative daily publication. In the event of changing market conditions, the Parties may review and mutually agree on changes to the period over which the average price of comparable crude oils may be calculated.

(b) (i) In relation to Crude Oil produced from the Existing Discoveries, the Parties agree that the initial price for sales of such Crude Oil to the Government or its nominee for the

purposes of Article 20.4(a) shall be the Far East term FOB selling price for Arabian Light per Barrel, applicable for the month in which the bill of lading/road challan date falls, as declared by Saudi Aramco, plus sixty (60) cents (US$0.60) per Barrel.

(ii) At least six (6) months prior to commencement of production from new Fields in the Contract Area, the Parties shall meet in order to establish a provisional list of the crude oils to be selected for comparison with the Crude Oil to be sold and an appropriate mechanism for the purpose of giving effect to Article 20.4(a) and definitively establishing the price of the Crude Oil to be sold pursuant to Article 20.4(a).

(c) In the event that, at the relevant time, no crude oils of similar quality to the Crude Oil to be sold are being actively traded in the international markets where prices can be ascertained by international publication, or the official FOB selling prices and the international spot market price vary widely between producers, the Parties shall meet in good faith to determine an appropriate pricing basis.

(d) The Parties shall meet annually, or sooner upon reasonable notice served by any Party on the others, to review the selected crude oil or oils and/or the mechanism established pursuant to Articles 20.4(a) and (b) to determine what adjustment (if any) should be made to the said selection or mechanism by mutual agreement of the Parties, provided that for the period of eighteen (18) months immediately following the Effective Date the price referred to in Article 20.4(b)(i) shall apply.

20.5 <u>Adjustment to Government Price Where Arms Length Price Differs</u>

In the event that in any Delivery Period, some but not all of a Contractor Party's sales of Crude Oil from a Field are made to the Government or a Government Company and some but not all are made to third parties in Arms Length Sales and the price as established in accordance with Article 20.4(a) differs by more than two percent (2%) from the price as determined in accordance with Article 20.3 for the same Delivery Period, the Parties shall meet, upon reasonable notice from any Party, to determine if the prices established for the relevant Delivery Period should be adjusted taking into account third party Arms Length Sales made by the Contractor

Party of the same or similar Crude Oil from the relevant Field or other Fields and published information in respect of other genuine third party Arms Length Sales of the same or similar crude oil for that Delivery Period. Until the matter of an adjustment for the relevant Delivery Period is finally determined, the price as established in accordance with this Article will apply for that Delivery Period. Any adjustment, if necessary, will be made within thirty (30) days from the date the adjustment for that Delivery Period is finally determined.

20.6 Contractor Party to Notify Government of Basis of Calculation of Price

A Contractor Party shall determine the relevant prices in accordance with this Article and the calculation, basis of calculation and the price determined shall be supplied to the Government or its nominee and shall be subject to agreement by the Government or its nominee before it is finally determined. Pending final determination, the last established price, if any, for the Crude Oil shall be used.

20.7 Disputes to be Referred to Sole Expert

(a) In the event that the Parties fail to reach agreement on any matter concerning selection of the crude oils for comparison, the calculation, the basis of, or mechanism for the calculation of the prices, the prices arrived at, the adjustment of any price or generally about the manner in which the prices are determined according to the provisions of this Article within thirty (30) days from the end of each Delivery Period, any Party may refer the matter or matters in issue for final determination by a sole expert appointed as provided in Article 34, provided that no such reference shall be made in relation to the eighteen (18) month period immediately following the Effective Date.

(b) Within ten (10) days of the said appointment, the Parties shall provide the expert with all information they deem necessary or as the expert may reasonably require.

(c) Within fifteen (15) days from the date of his appointment, the expert shall report to the Parties on the issue(s) referred to him for determination, applying the criteria or mechanism set forth herein and indicate his decision thereon to be applicable for the relevant Delivery Period for Crude Oil and such decision shall be accepted as final and binding by the Parties.

(d) Except for the adjustments referred to in Article 20.5, any price or pricing mechanism agreed by the Parties pursuant to the provisions of this Article shall not be changed retroactively.

20.8 Sales to Affiliates

Any sale or disposal to Affiliates or other sale or disposal of Crude Oil produced from a Field, other than to the Government or Government Companies or to third parties in Arms Length Sales, in any Delivery Period, shall be valued on the same basis as sales to the Government or a Government Company. In the event of such a sale or disposal by a Contractor Party, such Contractor Party shall submit to the Government, within fifteen (15) days of the end of each Delivery Period, all relevant information concerning such sales or disposals.

20.9 Calculation of Price Where More Than One Type of Sale

In the event that in any Delivery Period there is more than one type of sales referred to in Articles 20.3, 20.4 and 20.8, then, for the purpose of calculating Cost Petroleum and Profit Petroleum entitlement pursuant to Articles 15 and 16, a single price per Barrel of Crude Oil for all the sales for the relevant Delivery Period shall be used. Such single price shall be the weighted average of the prices determined for each type of sale, weighted by the respective volumes of Crude Oil sold in each type of sale in the relevant Delivery Period.

20.10 Government Nominee

In this Article, and in Articles 19 and 22 and the Accounting Procedure, the term "nominee" means a company wholly or partially owned by the Government (directly or indirectly) and shall include any other agency of the Government.

20.11 Provisions to Apply to Condensate

The provisions specified above for the determination of the price of sales of Crude Oil shall apply mutatis mutandis to Condensate.

20.12 Price of Natural Gas

The price of Natural Gas shall be determined as provided in Article 22.

ARTICLE 21

CURRENCY AND EXCHANGE CONTROL PROVISIONS

21.1 Rights of Foreign Companies

(a) Each Foreign Company comprising the Contractor shall, during the term of this Contract, have the right to:

(i) repatriate abroad, in United States Dollars and/or Australian Dollars and/or Japanese Yen and/or any other freely convertible currency acceptable to the Foreign Company, the net proceeds of sales of Petroleum in India;

(ii) receive, retain and use abroad the proceeds of any export sales of Petroleum under the Contract;

(iii) open, maintain and operate bank accounts with reputable banks, both inside and outside India, for the purpose of this Contract;

(iv) freely import, through normal banking channels, funds necessary for carrying out the Petroleum Operations;

(v) convert into foreign exchange and repatriate sums imported pursuant to (iv) above (including funds by way of loans from foreign third parties or Affiliates), in excess (if any) of its requirements; and

(vi) make payments outside of India for purchases, services and loans obtained abroad without the requirement that funds used in making such payments must come from or originate in India.

Provided however, that repatriation pursuant to subparagraphs (i) and (v) and payments pursuant to subparagraph (vi) shall be subject to the provisions of any treaties or bilateral arrangements between the Government and any country with respect to payments to that country.

(b) Companies shall comply with the relevant provisions of the applicable laws of India governing currency and foreign exchange and

related administrative instructions and procedures issued thereunder on a non-discriminatory basis.

21.2 Exchange Rates

The rates of exchange for the purchase and sale of currency by the Companies shall be the rates in accordance with prevailing currency and exchange regulations and, for accounting purposes under this Contract, these rates shall apply as provided in Section 1.6 of Appendix C.

21.3 Foreign Company Reporting Requirements

Foreign companies shall have full rights of control over movement of funds out of bank accounts established for the purpose of Petroleum Operations but shall provide to the Government or any body designated by it, monthly bank statements with an explanation of each deposit or payment from the account, and shall supply each Quarter, in a form acceptable to the Government, or such designated body, full particulars of foreign exchange transactions pursuant to this Contract in order to facilitate monitoring of such accounts. Such particulars shall include:

(a) details of deposits of proceeds of sales of Petroleum, such as quantity of Petroleum sold, date of sale and unit price;

(b) the repayment of principal of loans made to the Contractor in foreign currency for purposes of Petroleum Operations;

(c) payments of interest, charges, fees and expenses in respect of loans referred to in paragraph (b) above;

(d) payments in foreign currency to persons not resident in India for the supply of capital goods required for the purpose of Petroleum Operations;

(e) payments in foreign currency to persons not resident in India for the supply of goods and services, other than capital goods, required for Petroleum Operations (including services of foreign employees and consultants);

(f) amounts remitted to India or paid elsewhere at the request of the Government to meet obligations under the Contract; and

(g) retentions or disbursements to Affiliates in foreign currency representing the excess of net profits, depreciation and amortization over the

payments made under paragraphs (b) through (f) above.

The Government shall have the right at its sole cost to verify any statements and reports submitted by the Contractor pursuant to this Article and the Contractor shall promptly respond to any query made by the Government or the designated financial body to the reasonable satisfaction of the Government or such designated body.

ARTICLE 22

NATURAL GAS

22.1 Government Objectives to be Taken Into Account

Subject to Article 22.2, the Indian domestic market shall have the first call on the utilisation of Natural Gas produced from the Contract Area. Accordingly, any proposal by the Contractor relating to production of Natural Gas from the Contract Area shall be made in the context of the Government's policy for the utilisation of Natural Gas and shall take into account the objectives of the Government to develop its resources in the most efficient manner and to promote conservation measures.

22.2 Right to Use Natural Gas in Operations

Contractor shall have the right to use Natural Gas produced from the Contract Area for the purpose of Petroleum Operations including reinjection for pressure maintenance in the Oil Fields, gas lifting and power generation.

22.3 Natural Gas Sales and Access to GAIL Facilities

(a) Pursuant to Article 22.1, but subject to Articles 22.3(b) and 22.7(c), Contractor shall be free to sell privately, to any party in India; part or all of the Natural Gas to which Contractor is entitled under Articles 15 and 16.

(b) The Government shall be entitled to require Contractor to sell Natural Gas referred to in Article 22.3(a) (other than Natural Gas sold pursuant to Article 22.7(c)) to the Government PROVIDED THAT:

(i) the Government agrees to match the net price (taking into account all factors relevant to a calculation of such net price such as, but not limited to, payments in respect of sales tax, any other Government or State Government taxes, levies, imposts and the like with respect to the sale of Natural Gas, credit terms and transportation charges) and other material terms and conditions obtained by Contractor in respect of sales under Article 22.3(a) (other than sales pursuant to Article 22.7(c)); and

(ii) the Government notifies the Contractor in writing of such agreement within fourteen (14) Business Days from the date of receipt

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of notice in writing from Contractor specifying the said price and other material terms and conditions.

(c) Any Natural Gas not sold in accordance with Article 22.3(a) shall be offered for sale to the Government in accordance with the provisions of this Article 22.

(d) Contractor shall be entitled, subject to capacity being available, to transport Natural Gas sold to any party other than the Government pursuant to Article 22.3(a) through pipelines owned by Gas Authority of India Limited under generally accepted common carrier provisions in the international oil and gas industry.

22.4 Delivery Point

For the purpose of sales to the domestic market pursuant to this Article 22, the Delivery Point shall, unless otherwise provided herein or agreed, be the outlet flange of any facilities and operations established to process the said Natural Gas.

22.5 Associated Natural Gas (ANG)

(a) In the event that a New Discovery of Crude Oil contains ANG, Contractor shall declare in the proposal for the declaration of the said New Discovery as a Commercial Discovery as specified in Article 10, whether (and by what amount) the estimated production of ANG is anticipated to exceed the quantities of ANG which will be used in accordance with Article 22.2 (such excess being hereinafter referred to as "the Excess ANG"). In such an event the Contractor shall indicate whether, on the basis of the available data and information, it has reasonable grounds for believing that the Excess ANG could be commercially exploited in accordance with the terms of this Contract along with the commercial production of the Crude Oil from the Oil Field (or Fields), and whether the Contractor intends to so exploit the Excess ANG.

(b) Based on the principle of full utilisation and minimum flaring of ANG, a proposed development plan for an Oil Field (or Oil Fields), shall, to the extent practicable, include a plan for utilisation of the ANG from the New Discovery including estimated quantities to be flared, reinjected, and to be used for Petroleum Operations; and, if the Contractor proposes to commercially exploit the Excess ANG for sale in the domestic market in accordance with

Government's policy, or elsewhere, the proposed plans for such exploitation.

(c) An offer to the Government to sell Excess ANG shall be in writing and shall indicate to the extent possible the volume available and the timing of offtake. On receipt of such offer, the Government (or its nominee) shall, within three (3) months of the date of receipt thereof, notify the Contractor, in writing, whether or not it wishes to purchase the Excess ANG.

(d) If the Government elects to purchase the Excess ANG as provided in Article 22.5(c) then at least three (3) months prior to the anticipated date of the first delivery of Excess ANG the Contractor and the Government (or its nominee) shall agree on the terms for the sale to Government (or its nominee) of the Excess ANG, including the price and the mode and currency of payment. In the event that the Contractor and the Government are unable to agree on such terms then either or both of them may refer the matter to arbitration pursuant to Article 34.

(e) Where the Contractor is of the view that Excess ANG cannot be commercially exploited and chooses not to exploit the said ANG, or is unable to find a market for the Excess ANG pursuant to Article 22.3, the Government shall be entitled to take and utilise such Excess ANG.

(f) If the Government elects to take the Excess ANG as provided in Article 22.5(e):

(i) the Contractor shall deliver such Excess ANG to the Government (or its nominee) free of cost, at the downstream flange of the gas/oil separation facilities;

(ii) the Contractor shall, based on sound petroleum engineering practices, install such facilities as would facilitate, to the extent that such facilities do not interfere with Contractor's normal operations, the delivery of such Excess ANG to the Government or its nominee;

(iii) the cost of all facilities installed pursuant to paragraph (ii) above shall be charged to the Contract Area from which the Excess ANG is being produced as Development Costs or Production Costs, as the case may be, in accordance with the cost recovery provisions in Article 15;

(iv) the Government or its nominee shall bear all costs including gathering, treating, processing and transporting costs beyond the downstream flange of the gas/oil separation facilities; and

(v) the delivery of such Excess ANG shall be subject to procedures to be agreed between the Government or its nominee and the Contractor prior to such delivery, such procedures to include matters relating to timing of offtake of such Excess ANG.

(g) Excess ANG which is not commercially exploited by the Contractor, or taken by the Government or its nominee pursuant to this Article 22, shall be returned to the subsurface structure or flared where such flaring is approved in the Development Plan for the relevant Oil Field (or Oil Fields) or where reinjection is inadvisable in accordance with good reservoir engineering practices PROVIDED THAT Contractor shall at all times be entitled to flare Excess ANG which is not taken by Gas Authority of India Limited pursuant to the sales contract referred to in Article 22.7(c). All costs incurred in complying with this Article 22.5(g) shall be cost recoverable as Contract Costs.

(h) As soon as practicable after the Discovery referred to in Article 22.5(a) or the submission to Government of the proposal for the declaration of the said Discovery as a Commercial Discovery as therein specified or the submission of the proposed Development Plan referred to in Article 22.5(b), the Contractor and the Government or its nominee shall meet to discuss the sale and/or disposal of any ANG discovered with a view to giving effect to the provisions of this Article 22 in a timely manner.

22.6 Non Associated Natural Gas (NANG)

(a) In the event of a New Discovery of NANG in the Contract Area, the Contractor shall promptly report such Discovery to the Management Committee and the Government and the provisions of Articles 10.1 and 10.2 shall apply. The remaining provisions of Article 10 shall apply to the discovery and development of NANG only insofar as they are not inconsistent with the provisions of this Article.

(b) If, pursuant to Article 10.1, the Contractor gives notification that a New Discovery is of potential commercial interest, the Contractor shall submit to the Management Committee, within one (1)

calendar year from the date of notification of the above said New Discovery, the proposed appraisal programme, including a Work Programme and Budget to carry out an adequate and effective appraisal of such New Discovery, to determine (i) without delay, whether such New Discovery is a Commercial Discovery and (ii) with reasonable precision, the boundaries of the area to be delineated as a Field. Such programme shall be supported by all relevant data such as Well data, Contractor's best estimate of reserve range and production potential and shall indicate the date of commencement of the proposed appraisal programme.

(c) The proposed appraisal programme referred to in Article 22.6(b) shall be considered by the Management Committee within one hundred and twenty (120) days of its submission by the Contractor and the said programme together with the Work Programme and Budget submitted by the Contractor revised in accordance with any agreed amendments or additions thereto approved by the Management Committee, shall be adopted as the Appraisal Programme and the Contractor shall promptly proceed with implementation of the said programme.

(d) If on the basis of the results of the Appraisal Programme, the Contractor is of the opinion that NANG has been discovered in commercial quantities, it shall submit to the Management Committee, as soon as practicable but not later than five (5) years from the date of notification of the aforementioned Discovery, a proposal for the declaration of the Discovery as a Commercial Discovery. Such proposal shall take into account the Government's policies on gas utilisation and propose alternative options (if any) for use or consumption of the NANG and be supported by, inter alia, technical and economic data, evaluations, interpretations and analyses of such data, feasibility studies relating to the Discovery prepared by or on behalf of the Contractor and any other relevant information. If no proposal is submitted to the Management Committee by the Contractor within five (5) years from the date of the notification of the said New Discovery, the Contractor shall relinquish its rights to develop such Discovery and the area relating to such Discovery shall be excluded from the Contract Area.

(e) In the case of a New Discovery, simultaneously with the Contractor's Appraisal Programme, Government and the Contractor shall seek to reach an agreement on the development, production, processing, utilization and sale of the NANG, in

the context of Article 22.1, within five (5) years of the date of notification of the New Discovery referred to in Article 22.6(a).

(f) Where the Contractor has submitted a proposal for the declaration of a New Discovery as a Commercial Discovery, the Management Committee shall consider the proposal of the Contractor with reference to commercial utilization or commercial development of the NANG in the domestic market or elsewhere and in the context of Government's policy on gas utilisation and the chain of activities required to bring the NANG from the Delivery Point to potential end consumers in the domestic market or elsewhere. The Management Committee may, within ninety (90) days, request the Contractor to submit any additional information on the Discovery, the anticipated markets or any other related matter that it may reasonably require to facilitate a decision on whether or not to declare the Discovery as a Commercial Discovery.

(g) The Management Committee shall submit the proposal of the Contractor, with its recommendations, to the Government within one hundred and eighty (180) days of the date of receipt of the said proposal and the Government shall respond within one hundred and twenty (120) days of receipt of the said proposal from the Management Committee.

(h) If the Management Committee, with the approval of the Government, declares a New Discovery a Commercial Discovery, such declaration or approval shall be accompanied by an indication of the probable date(s) by when the market(s) would be ready to receive the Gas and an estimate of the quantities of Gas that could be so utilized. The Contractor, in such an event, shall, within one (1) calendar year of the declaration of the New Discovery as a Commercial Discovery, submit a Development Plan for the development of the Gas Field to the Management Committee for its approval. Such plan shall be supported by all relevant information including, inter alia, the information required in Article 10.7.

(i) If the Development Plan has not been approved by the Management Committee within one hundred and eighty (180) days of its submission, the Contractor shall have the right to submit such plan or plans directly to the Government for approval, within sixty (60) days of the expiry of the time provided to the Management Committee to approve the said plan or plans and the Government shall respond to the said submission within ninety (90) days of receipt thereof. If the Government

disapproves the Contractor's proposed plan or plans, the Government shall state in writing the reasons for such disapproval and the Contractor shall have the right to resubmit, within sixty (60) days of communication of such disapproval, such plan or plans duly amended to meet the Government's objections thereto. Such right of resubmission of each proposed plan or plans shall be exercisable by the Contractor only once. If no such plan or plans is/are submitted to the Government within the above specified period, the Contractor shall relinquish its rights to develop such Gas Field and such Gas Field shall be excluded from the Contract Area.

(j) If the Management Committee is unable to agree on the declaration of a New Discovery as a Commercial Discovery within the time limit prescribed in Article 22.6(g), the Contractor shall be entitled to submit such proposal directly to the Government for approval. In such an event, the Contractor shall also submit a comprehensive plan or plans for development of such New Discovery, which shall detail the proposed development plan for utilization of the NANG produced in the domestic market giving, inter alia, the data specified in Article 22.6(h) above. The proposal for declaration of the New Discovery as a Commercial Discovery as well as the proposed development plan shall be submitted to the Government within one hundred and eighty (180) days of the expiry of the time given to the Management Committee to reach a decision on the Contractor's proposal for declaration of the New Discovery as a Commercial Discovery and Government shall respond to the said submission within sixty(60) days of its receipt. If the Government disapproves the Contractor's proposed plan or plans, the Government shall state in writing the reasons for such disapproval and the Contractor shall have the right to resubmit, within sixty (60) days, such plan or plans duly amended to meet the Government's objections thereto. Such right of resubmission of each proposed plan or plans shall be exercisable by the Contractor only once. If no such plan or plans is/are submitted to the Government within the aforesaid period, the Contractor shall relinquish its rights to develop such Gas Field and such Gas Field shall be excluded from the Contract Area.

(k) In the event the Management Committee, under Article 22.6(h), or the Government, under Article 22.6(j), as the case may be, approves the Contractor's proposal for declaration of the New Discovery as a Commercial Discovery and also the comprehensive plan or plans for development of any

Discovery for the utilization of NANG produced in the domestic market, with such modifications and amendments as the Management Committee or the Government, as the case may be, may decide, the said Gas Field shall be promptly developed by the Contractor in accordance with the approved plan which shall be the Development Plan for the Field.

(l) In the event the Contractor does not commence development of a New Discovery within ten (10) years from the date of completion of the first Discovery Well, the Contractor shall relinquish its rights to develop such Discovery and the area relating to such Discovery shall be excluded from the Contract Area.

(m) The price of the NANG produced from the Gas Field (other than in respect of NANG produced from the Existing Discoveries) for use in India shall, unless the Contractor and the Government mutually agree otherwise, be determined at the Delivery Point and shall be related to the thermal equivalence price of imported fuel oil. The formula on which the price shall be based and determined shall be mutually agreed and specified prior to the declaration of any New Discovery of NANG as a Commercial Discovery.

22.7 Existing Discoveries - ANG and NANG; Sales to Gas Authority of India Limited

(a) The Parties acknowledge and agree that the Ravva Development Plan satisfies all of the relevant provisions of Articles 22.5 and 22.6 with respect to the development of Excess ANG and NANG within the Existing Discoveries such that no further procedures remain to be satisfied or approvals obtained to permit the Parties to develop such Natural Gas.

(b) The Parties acknowledge and agree that, except as otherwise expressly provided therein, Articles 22.5 and 22.6 apply only to New Discoveries and, furthermore, are subject to the provisions of Article 11 (Development and Production from Existing Discoveries and Satellite Fields).

(c) (i) Each of the Parties comprising Contractor ("Seller") severally agrees that it will sell its Participating Interest share of Natural Gas produced pursuant to the Ravva Development Plan to Gas Authority of India Limited ("GAIL").

(ii) The Government undertakes to each of the Parties comprising Contractor that it shall

procure that GAIL shall purchase such Gas on the following terms and conditions:

(aa) the Gas purchase price per net million British Thermal Units ("MMBTU's") shall be fixed for each Quarter and shall be one hundred per cent (100%) of the average of the daily mean values of the low and high prices of 3%/3.5% sulphur residual fuel oil taking into account equal parts of Singapore FOB, Rotterdam Barge and MED FOB, as published in Platt's for the last twelve (12) months preceding the first month of the Quarter ("the purchase price"), provided that for the period of five (5) years from the date of first delivery of Gas the purchase price shall not be:

(1) lower than ninety-five per cent (95%) of that calculated as at the Effective Date by applying the foregoing formula; and

(2) higher than three (3) United States Dollars (US$3.00) per net MMBTU's.

Following the expiration of the said five (5) year period the parties shall enter into good faith negotiations to renegotiate the basis for calculation of the purchase price taking into account all reasonably relevant factors. In the event that the parties are unable to agree on a new purchase price for Gas any party may refer the dispute for resolution by a sole expert in accordance with the provisions of Article 34.2.

(bb) Seller shall be responsible for payment of any Royalty, levy or taxes imposed by the Government, a State Government or a local authority, with respect to the production of Gas delivered at the delivery point. However, GAIL shall reimburse Seller any sales tax payable by Seller to the Government, State Government or local authority on account of the sale and/or transfer of ownership of Gas to GAIL at the delivery point;

(cc) the specification for such Gas shall comply with GAIL pipeline quality standards, including delivery pressure of not less than 70 kgs/cm^3 and net calorific value of not less than 9,000 KCal/SCM;

(dd) the delivery point shall be the downstream flange at the inlet of GAIL's metering station to be located in or adjacent to Seller's onshore terminal facilities at Surasaniyanam, India;

(ee) Gas delivered to GAIL shall be transported from the delivery point by means of a pipeline to be provided and maintained by GAIL. GAIL shall proceed with due diligence to market the Gas delivered to it and shall construct its facilities in a timely manner so as to enable it to meet its purchase obligations;

(ff) title, control and risk of loss of the Gas shall pass from Seller to GAIL at the delivery point;

(gg) delivery of Gas shall commence on or about the first day of June, 1996 or such earlier date as the parties may agree; and

(hh) such other terms and conditions as are normally found in gas sales contracts in the international gas industry.

(iii) The Government further undertakes that it shall procure that GAIL shall:

(aa) enter into good faith negotiations with each of the Parties comprising Contractor to conclude a formal agreement for the purchase of such Gas on the abovementioned terms and conditions, such agreement to be executed within six (6) months from the Effective Date or such other date as GAIL and the said Parties may agree; and

(bb) agree to submit any dispute with the said Parties regarding the abovementioned terms and conditions for decision by a sole expert in accordance with the provisions of Article 34.2.

ARTICLE 23

EMPLOYMENT AND TRANSFER OF TECHNOLOGY

23.1 Indian Citizens to be Employed to Maximum Extent Possible

Without prejudice to the right of the Contractor to select and employ or engage such number of personnel and/or consultants as, in the opinion of the Contractor, are required for carrying out Petroleum Operations in a safe, cost effective and efficient manner, the Contractor shall, to the maximum extent possible, employ, and require the Operator and Subcontractors to employ, citizens of India having appropriate qualifications and experience, taking into account experience required in the level and nature of the Petroleum Operations.

23.2 No Obligation to Disclose Proprietary Information

No Party shall be obliged to disclose by virtue of this Article 23 any data, process or information, whether owned by itself, any of its Affiliates or a third party, of a proprietary nature.

23.3 Foreign Company Technical Assistance Agreements

At the request of the Government or a Government Company, the Foreign Companies shall separately endeavour to negotiate, in good faith, technical assistance agreements with the Government or a Government Company setting forth the terms by which each Foreign Company constituting the Contractor may render technical assistance and make available commercially proven technical information of a proprietary nature for use in India by the Government or a Government Company. The issues to be addressed in negotiating such technical assistance agreements shall include, but not be limited to, licensing issues, royalty conditions, confidentiality restrictions, liabilities, costs and method of payment.

ARTICLE 24

LOCAL GOODS AND SERVICES

24.1 Preference to be Given to Indian Goods and Services

In the conduct of Petroleum Operations, the Contractor shall:

(a) give preference to the purchase and use of goods manufactured, produced or supplied in India provided that such goods are available on terms equal to or better than imported goods with respect to timing of delivery, quality and quantity required, price and other terms;

(b) employ Indian Subcontractors having the required skills or expertise, to the maximum extent possible, insofar as their services are available on comparable standards with those obtained elsewhere and at competitive prices and on competitive terms; provided that where no such Subcontractors are available, preference shall be given to non-Indian Subcontractors who utilise Indian goods to the maximum extent possible subject however to the proviso in paragraph (a) above;

(c) cooperate with domestic companies in India to enable them to develop skills and technology to service the petroleum industry;

(d) ensure to the best of its ability that provisions in terms of paragraphs (a) to (c) above are contained in contracts between the Operator and its Subcontractors; and

(e) ensure that suppliers and Subcontractors in India are given adequate opportunity to compete for the supply of goods and services.

24.2 Contractor to Report on Utilisation of Indian Resources

Within one hundred and twenty (120) days after the end of each Year, the Contractor shall provide the Government with a report outlining its achievements in utilising Indian resources during that Year.

24.3 Definition of "Goods"

In this Article "goods" means equipment, materials and supplies.

ARTICLE 25

INSURANCE AND INDEMNIFICATION

25.1 Insurance

(a) The Contractor shall, during the term of this Contract, obtain and renew, as and when necessary, insurance coverage for and in relation to Petroleum Operations for such amounts and against such risks as are customarily or prudently insured in the international petroleum industry in accordance with good international petroleum industry practices, and shall furnish to the Government certificates evidencing that such coverage is in effect. Such insurance policies shall include the Government as additional insured, and, if required by a lender to a Party, such lender, and shall waive subrogation against the Government and any lender named as an insured party. The inclusion of a lender shall be without prejudice to the rights of the Government. The said insurance shall, without prejudice to the generality of the foregoing, cover:

(i) Loss or damage to all installations, equipment and other assets for so long as they are used in or in connection with Petroleum Operations; provided, however, that if for any reason the Contractor fails to insure any such installation, equipment or assets, it shall replace any loss thereof or repair any damage caused thereto;

(ii) Contractor's liability under this Contract for loss, damage or injury caused by pollution in the course of or as a result of Petroleum Operations;

(iii) Loss of property or damage or bodily injury suffered by any third party in the course of or as a result of Petroleum Operations for which the Contractor may be liable;

(iv) Any claim for which the Government may be liable relating to the loss of property or damage or bodily injury suffered by any third party in the course of or as a result of Petroleum Operations for which the Contractor is liable to indemnify the Government;

(v) With respect to Petroleum Operations offshore, the cost of removing wrecks owned or chartered by Contractor and cleaning up

operations following any accident directly as a result of Petroleum Operations; and

(vi) The Contractor's and/or the Operator's liability to its employees engaged in Petroleum Operations.

(b) The Contractor shall require its Subcontractors to obtain and maintain insurance against the risks referred to in Article 25.1(a) relating mutatis mutandis to such Subcontractors.

25.2 Indemnity

(a) Subject to paragraphs (b) and (c) of this Article 25.2 and to Article 4.3 the Contractor shall indemnify, defend and hold the Government harmless against all claims, losses and damages of any nature whatsoever, including, (without limitation, claims for loss or damage to property or injury or death to persons) caused by or resulting from the Gross Negligence of the Contractor in carrying out Petroleum Operations after the Effective Date.

(b) Subject to the provisions of this Contract, each Party shall indemnify and keep indemnified each of the other Parties from every claim, demand, action, liability or loss resulting from each and every breach or default by the indemnifying Party of any of its obligations under this Contract.

(c) The Contractor shall not be liable under any circumstances for any consequential or indirect loss or damages which, for the purposes of this Contract, shall include but not be limited to inability to produce Petroleum, lost production in respect of the Petroleum Operations or loss of profits arising therefrom. Nothing in this Article 25.2(c) shall relieve a Company comprising Contractor from its obligations with respect to the requirements of this Contract relating to achieving the production profile referred to in the Ravva Development Plan.

(d) Each of the Government and ONGC severally agrees to indemnify, defend and hold harmless the Companies against all claims, losses and damages of any nature whatsoever including, without limitation, claims for loss or damage to property or injury or death to persons caused by or resulting from any activities of ONGC with respect to the exploration for or the production, treatment, storage or transportation of Petroleum in or from the Contract Area or the facilities at Surasaniyanam prior to the Effective Date.

ARTICLE 26

RECORDS, REPORTS, ACCOUNTS AND AUDIT

26.1 Contractor to Maintain Records in India

The Contractor shall prepare and maintain at an office in India accurate and current books, records, reports and accounts of its activities for and in connection with Petroleum Operations so as to present a fair, clear and accurate record of all its activities, expenditures and receipts. The Contractor shall also keep representative samples of cores and cuttings.

26.2 Operator to Maintain Records on Behalf of Contractor

Based on generally accepted and recognised accounting principles and modern international petroleum industry practices, records, books, accounts and accounting procedures in respect of Petroleum Operations shall be maintained on behalf of the Contractor by the Operator at its business office in India, in accordance with the Accounting Procedure.

26.3 Annual Audit

The annual audit of accounts shall be carried out on behalf of the Contractor by a qualified, independent firm of recognised chartered accountants, registered in India and selected by the Contractor with the approval of the Management Committee.

26.4 Annual Accounts

Accounts, together with the auditor's report thereon, shall be submitted to the Parties for approval not later than the thirtieth (30th) September following the Financial Year.

26.5 Government Right to Audit

The Government shall have the right to audit the accounting records of the Contractor in respect of Petroleum Operations as provided in the Accounting Procedure.

26.6 Applicability of Indian Laws

The accounting and auditing provisions and procedures specified in this Contract are without prejudice to any other requirements imposed by any statute in India, including, without limitation, any specific requirements of the statutes relating to taxation of companies.

26.7 Contractor to Make Records Available

For the purpose of any audit referred to in Article 26.5 the Contractor shall make available to the auditor all such books, records, accounts and other documents and information as may be reasonably required by the auditor.

ARTICLE 27

INFORMATION, DATA, CONFIDENTIALITY, INSPECTION AND SECURITY

27.1 Contractor to Provide Data to Government

The Contractor shall, promptly after they become available, provide the Government with all data obtained as a result of Petroleum Operations under the Contract including, but not limited to, geological, geophysical, geochemical, petrophysical, engineering, well logs, maps, magnetic tapes, cores and production data as well as all interpretative and derivative data, including reports, analyses, interpretations and evaluation prepared in respect of Petroleum Operations (hereinafter referred to as "Data"). Data shall be the property of ONGC, provided, however, that the Companies shall have the right to make use of such Data, free of cost, for the purpose of Petroleum Operations under this Contract as provided herein and for the purpose of funding their obligations hereunder.

27.2 Contractor's Right to Retain Material, Etc.

Contractor may, for use in Petroleum Operations, retain copies or samples of material or information constituting the Data and, with the approval of ONGC, original material, except that where such material is capable of reproduction and copies have been supplied to ONGC, Contractor may, subject to the right of inspection by ONGC, export samples or other original Data for processing or laboratory examination or analysis, provided that representative samples equivalent in quality, size and quantity, or, where such material is capable of reproduction, copies of equivalent quality, have first been delivered to ONGC.

27.3 Contractor to Report on Petroleum Operations

Contractor shall keep the Government currently advised of all developments taking place during the course of Petroleum Operations and shall furnish ONGC with all information and reports relating to Petroleum Operations as required by the Operating Agreement, provided that this obligation shall not extend to proprietary technology. Without prejudice to the generality of the foregoing, the Contractor shall submit regular statements and reports relating to Petroleum Operations as provided in Appendix C. Contractor shall meet with the Government at a mutually convenient location to present the results of all geological and geophysical work carried out as well as the results of all engineering and drilling operations as soon as such Data becomes available to the Contractor.

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27.4 Confidentiality of Data

All Data, information and reports obtained or prepared by, for or on behalf of, the Contractor pursuant to this Contract shall be treated as confidential and, subject to the provisions hereinbelow, the Parties shall not disclose the contents thereof to any third party without the consent in writing of the other Parties.

27.5 Permitted Disclosures

The obligation specified in Article 27.4 shall not operate so as to prevent disclosure:

(a) to Affiliates, contractors, or Subcontractors for the purpose of Petroleum Operations;

(b) to employees, professional consultants, advisers, data processing centres and laboratories, where required, for the performance of functions in connection with Petroleum Operations for any Party comprising the Contractor;

(c) to banks or other financial institutions, in connection with Petroleum Operations;

(d) to bona fide intending assignees or transferees of a Participating Interest of a Party comprising the Contractor or in connection with a sale of the whole of the issued stock or shares of a Party comprising the Contractor;

(e) to the extent required by any applicable law or in connection with any legal proceedings or by the regulations of any stock exchange upon which the shares of a Party comprising Contractor (including an Affiliate) are quoted;

(f) to Government departments for, or in connection with, the preparation by or on behalf of the Government of statistical reports with respect to Petroleum Operations, or in connection with the administration of this Contract or any relevant law; or

(g) by a Party with respect to any Data or information which, without disclosure by such Party, is generally known to the public.

27.6 Recipient to Treat Data Confidentially

Any Data, information or reports disclosed by the Parties comprising the Contractor to any other person pursuant to Article 27.5 (a) to (d) shall be disclosed on the terms that such Data, information or reports shall be treated as confidential by the recipient.

27.7 Permitted Disclosure by Government

Any Data, information and reports relating to the Contract Area which, in the opinion of the Government, might have significance in connection with offers by the Government of open acreage or an exploration programme to be conducted by a third party in another area, may be disclosed by the Government for such purposes on conditions to be agreed upon between the Government and the Contractor.

27.8 Government's Right to Observe and Inspect

The Government shall, in consultation with the other Parties comprising Contractor, at all reasonable times, through duly authorised representatives, be entitled to observe Petroleum Operations in the Contract Area and to inspect all assets, books, records, reports, accounts, contracts, samples and Data kept by the Contractor or the Operator in respect of Petroleum Operations under the Contract, provided, however, that the Companies shall not be required to disclose any proprietary technology. The duly authorised representatives shall be given reasonable assistance by the Contractor for such functions and the Contractor shall afford such representatives all facilities and privileges afforded to its own personnel in the field at cost and the use of office space and housing at cost. The said representatives shall, in discharge of their functions under this Contract, be entitled to make a reasonable number of surveys, measurements, drawings, tests and copies of documents, take samples, and for this purpose make reasonable use of the equipment and instruments of the Contractor provided that such functions shall not unduly interfere with the Contractor's Petroleum Operations. The Government shall indemnify and [illegible] harmless the Contractor from all claims by or on [illegible] of such representatives in respect of loss or [illegible] arising out of the death of or personal injury to such representatives whilst performing their functions hereunder.

27.9 Contractor to Notify Government of Aircraft and Vessels Movements

Contractor shall give reasonable advance notice to the Government, or to any other authority designated by the Government for such purpose, of its programme of conducting surveys by aircraft or by ship, indicating, inter alia, the name of the survey to be conducted, approximate extent of the area to be covered, duration of the survey, the commencement date and the name of the airport or port from which the said aircraft or ship will commence its voyage.

27.10 Government's Right of Inspection of Aircraft and Ships

The Government, or the authority designated by the Government for such purpose, shall have the right to inspect any aircraft or ship used by the Contractor or a Subcontractor carrying out any survey or other operations in the Contract Area and shall have the right to put on board such aircraft or ship Government officers in such number as may reasonably be necessary to ensure compliance by the Contractor or the Subcontractor with the security requirements of India.

ARTICLE 28

TITLE TO PETROLEUM, DATA AND ASSETS

28.1 Ownership of Petroleum

The Government is the sole owner of Petroleum underlying the Contract Area and shall remain the sole owner of Petroleum produced pursuant to the provisions of this Contract except as regards that part of Crude Oil or Gas the title whereof has passed to the Contractor or any other person in accordance with the provisions of this Contract.

28.2 Title to Petroleum to Pass at Delivery Point

Title to Crude Oil and/or Gas to which Contractor is entitled under this Contract, and title to Crude Oil and/or Gas sold to Government or its nominee by the Companies shall pass to the relevant Party or, as the case may be, to Government or its nominee at the Delivery Point. Contractor shall be responsible for all costs and risks prior to the Delivery Point and each Party shall be responsible for all costs and risks associated with such Party's share after the Delivery Point and where the Government or its nominee purchases all or some of the Companies' share of Crude Oil in accordance with Article 19, Government or its nominee shall be responsible for all costs and risks in respect of the amount purchased, after the Delivery Point.

28.3 Title to Data

Title to all Data specified in Article 27 shall be vested in ONGC and the Contractor shall have the right to the use thereof as therein provided.

28.4 Title to Assets

Assets purchased by the Contractor for use in Petroleum Operations shall be owned by the Parties comprising Contractor in proportion to their Participating Interests provided that ONGC shall have the right to require vesting of full title and ownership in it, free of charges and encumbrances, of any or all assets, whether fixed or movable, acquired and owned by the Contractor for use in Petroleum Operations inside or outside the Contract Area, such right to be exercisable at ONGC's option either when ninety five percent (95%) of the original cost of the asset acquired has been written off in accordance with the depreciation rates specified in Schedule XIV of the Companies Act,1956, or upon expiry or earlier termination of the Contract. The proceeds of any insurance claim in respect of the damage, loss or destruction of an asset title to which

has vested in ONGC pursuant to this Article 28.4 shall be applied toward the repair and/or replacement of such asset. For the avoidance of doubt the Parties hereby agree the "assets" for the purposes of this Article 28 do not include material held in inventory and not charged to the accounts in accordance with paragraph 3.1.8 (i) of the Accounting Procedure.

28.5 Maintenance, Insurance and Safety of Assets

Contractor shall be responsible for proper maintenance, insurance and safety of all assets acquired for Petroleum Operations (whether before or after the Effective Date) and for keeping them in good repair, order and working condition at all times, and the costs thereof shall be recoverable as Contract Costs in accordance with Appendix C.

28.6 Contractor to Have Use and Custody of Assets

So long as this Contract remains in force, the Contractor shall, free of any charge, for the purpose of carrying out Petroleum Operations hereunder, have the exclusive use and custody of the assets which have become the property of ONGC subject, however, to Article 28.5.

28.7 ONGC Right of First Refusal Re Assets

Subject to Article 28.4, equipment and assets, which ONGC has not taken title to pursuant to its rights under this Contract, and which are no longer required for Petroleum Operations shall first be offered to ONGC for purchase and, if not required by ONGC, shall be sold or exchanged by the Contractor, provided however that prior consent of the Management Committee shall be obtained for each transaction where the market value of the equipment and assets are in excess of US$20,000 or such other amounts as may be agreed from time to time, such consent not to be unreasonably withheld, and provided further that the proceeds of sale shall be credited to Petroleum Operations as provided in Appendix C.

ARTICLE 29

ASSIGNMENT OF INTEREST, CHARGES AND ENCUMBRANCES AND WITHDRAWAL

29.1 Assignment Subject to Government Approval

(a) Subject to the terms of this Article and other terms of this Contract, any Party comprising the Contractor, or that Party's Permitted Chargee (as hereinafter defined), may assign, or transfer, a part or all of that Party's Participating Interest, with the prior written consent of the Government, which consent shall not be unreasonably withheld, provided that the Government is satisfied that:

(i) the prospective assignee or transferee is capable of meeting its financial and, if appropriate, technical obligations under this Contract, and is willing to provide an unconditional undertaking in favour of all Parties to assume its Participating Interest share of obligations and to provide a guarantee in respect thereof as provided in Article 30;

(ii) the prospective assignee or transferee is not a company incorporated in a country with which the Government, for policy reasons, has restricted trade or business; and

(iii) the assignment or transfer will not be contrary to the interests of India and the prospective assignee or transferee is willing to comply with any bona fide conditions as may be imposed by the Government in the national interest.

(b) The Government shall not withhold its consent where the assignment or transfer to another Party comprising Contractor is as a result of the operation of the default or withdrawal provisions of the Operating Agreement (being Articles 7.6 - 7.8 and Article 11 of the Operating Agreement respectively) or, subject to Article 29.1(a), where the assignment or transfer is made to a company listed or to be listed on a recognised stock exchange, and where, after such assignment or transfer, the assigning Party will hold twenty five percent (25%) or more of the issued capital of such company.

(c) For the purposes of the Article 29, the expression "Permitted Chargee" means a holder of a mortgage,

charge or other encumbrance over all or part of a Party's Participating Interest given in accordance with Article 29.8(a).

29.2 Application For Government Consent

An application by a Company for consent to assign or transfer shall be accompanied by all relevant information concerning the proposed assignment or transfer including detailed information on the proposed assignee or transferee and its shareholding and corporate structure, as was earlier required from the Companies constituting the Contractor, the terms of the proposed assignment or transfer and the unconditional undertaking referred to in Article 29.1(a). The applicant shall also submit such information relating to the prospective assignee or transferee of the assignment or transfer as the Government may reasonably require to enable proper consideration and disposal of the application.

29.3 Assignment Not Effective Until Government Consent Received

No assignment or transfer shall be effective until the approval of the Government is received or deemed to have been received. The Government's approval or rejection of an assignment or transfer shall be notified to the Party or Permitted Chargee applying for such approval within sixty (60) days of receipt of the application provided such application is in accordance with Article 29.2. Any rejection shall be accompanied by reasons in writing for such rejection. In the event that no notice has been received by the applicant approving or rejecting the application within the said sixty (60) day period, the application shall be deemed to have been approved. Upon assignment or transfer of its interest in this Contract, the assignor or transferor shall be released and discharged from its obligations hereunder only to the extent that such obligations are agreed to be assumed by the assignee or transferee.

29.4 Assignee Liable For Future Obligations

The assignor shall clearly state in its deed of assignment, that the assignee shall be liable for all his obligations, whether past, present or future, under the Contract, to the extent of assignment.

29.5 ONGC Right to Assign

Upon prior notice to the Companies, ONGC may assign or transfer all or any part of its rights and interest under this Contract to any company wholly or majority owned by the Government and authorised by the Government to explore for and exploit petroleum in the Contract

Area PROVIDED THAT such assignee shall be bound by the terms and conditions of this Contract and the Operating Agreement.

29.6 Minimum Participating Interest of 10%

An assignment or transfer shall not be made where the Participating Interest to be retained by the Party whose Participating Interest is the subject of the proposed assignment or the Participating Interest of the proposed assignee will be less than ten percent (10%) of the total Participating Interests, except where the Government, on the recommendations of the Management Committee may, in special circumstances, so permit.

29.7 Assignment to Affiliate

(a) Subject to Articles 29.1, 29.4 and 29.6, nothing in this Article 29 shall prevent a Party comprising Contractor from assigning a part or all of its Participating Interest to an Affiliate, provided that the Party so assigning provides a guarantee issued by the guarantor which furnished the performance guarantee in respect of the assigning Party's obligations under this Contract pursuant to Article 30.1, in favour of the non-assigning Parties, of the performance of such Affiliate of its obligations under this Contract. In the event that the assignee is an Affiliate of ONGC then ONGC shall provide such guarantee.

(b) Where a guarantor referred to in Articles 31.1(b) and (c) is an Affiliate of the Company therein referred to and such guarantor complies with the guarantee provided by it pursuant to Article 30.1(a), it shall be entitled to an assignment and transfer of such Company's Participating Interest. No consents or approvals shall be required in respect of such assignment.

29.8 Right to Charge Participating Interest

(a) Nothing contained in this Article 29 shall prevent a Party comprising Contractor from mortgaging, pledging, charging or otherwise encumbering all or part of its Participating Interest for the purposes of security relating to finance required for performing the Contract, provided that:

(i) such Party shall remain liable for all obligations relating to its Participating Interest;

(ii) the encumbrance shall be expressly subordinated to the rights of the other Parties under this Contract;

(iii) such Party has given reasonable notice of such encumbrance and furnishes to all other Parties (including, for the avoidance of doubt, the Government) a certified copy of the executed instrument or instruments evidencing the encumbrance; and

(iv) prior consent of the Government shall be required (which consent shall not be unreasonably withheld) in connection with the hypothecation to any lender with international sensitivities for the Government.

(b) The Parties acknowledge that to obtain financing a Party ("Borrower") will be required to secure for a Permitted Chargee the right to receive a copy of any notice served on the Borrower pursuant to Article 31.1 and the Parties agree that they shall serve a copy of any such notice on any such Permitted Chargee in accordance with the provisions of Article 37 at the same time as such notice is served on the Borrower. For the purposes of Article 37 the address for service of notices of the Permitted Chargee shall be that specified in the instrument or instruments referred to in Article 29.8(a)(iii) as may be amended from time to time by notice by the Permitted Chargee to the Parties.

29.9 Withdrawal By a Party

Any Party comprising Contractor may withdraw from this Contract after the implementation of the Ravva Development Plan with the prior written consent of the Government subject to the fulfillment of such reasonable terms and conditions as may be imposed by the Government as a prerequisite for such withdrawal.

ARTICLE 30

GUARANTEES

30.1 Requirement to Provide Guarantee and Legal Opinion

Each of the Companies shall procure and deliver to the Government within fifteen (15) days of the Effective Date of this Contract:

(a) a performance guarantee, for the performance of all obligations under the Contract, from an Affiliate of good financial standing acceptable to the Government or from a reputable financial institution or insurance company acceptable to the Government, in favour of the Government and ONGC, in the form and substance set out in Appendix E;

(b) a legal opinion from its legal advisors (including a legal advisor who is an employee of the Company), in a form satisfactory to the Government, to the effect that the aforesaid guaranteehas been duly signed and delivered on behalf of the guarantorwith due authority and is legally valid and enforceable and binding upon it.

30.2 Guarantee by Affiliate Not Affected by Change in Shareholding

Notwithstanding any change in the composition or shareholding of the Affiliate furnishing the guarantees herein, it shall not, under any circumstances, be absolved of its obligations contained in the guarantees provided pursuant to this Article.

ARTICLE 31

TERMINATION OF CONTRACT

31.1 Circumstances in which Government May Terminate

This Contract may, subject to the provisions hereinbelow and Article 32, be terminated by the Government upon giving ninety (90) days written notice of its intention to do so to the other parties in the following circumstances, namely, that a Company ("Defaulting Company"):

(a) has knowingly submitted any false statement to the Government in any manner which was a material consideration in the entry into of this Contract; or

(b) is adjudged bankrupt by a competent court or enters into a scheme of composition with, or an assignment for the benefit of, all or any class of its creditors generally and the guarantor of such Company fails to comply with the provisions of the guarantee given by it pursuant to Article 30 following all reasonable attempts by the Government to enforce such guarantee; or

(c) has passed a resolution to apply to a competent court for liquidation of the Company and the guarantor of such Company fails to comply with the provisions of the guarantee given by it pursuant to Article 30 following all reasonable attempts by the Government to enforce such guarantee, unless the liquidation is for the purpose of amalgamation or reconstruction of which the Government has been given notice and the Government is satisfied that the Company's performance under this Contract would not be adversely affected thereby and has given its approval thereto;. or

(d) fails to make any monetary payment required by law with respect to Petroleum Operations (but not otherwise) or under this Contract by the due date or within such further period after the due date as may be specified in this Contract, the Operating Agreement or by law; or

(e) fails to comply with or contravenes the provisions of this Contract in a material particular; or

(f) fails to comply with any final determination or award made by a sole expert or arbitration pursuant to Article 34; or

(g) has failed to deliver the documents referred to in Article 30.1 within the period therein specified.

PROVIDED THAT where the Contractor comprises two or more Companies, the Government shall not exercise its rights of termination pursuant to Article 31.1, on the occurrence, in relation to one or more, but not all, of the Companies, of an event entitling the Government to terminate the Contract:

(i) if any other Company or Companies constituting the Contractor ("the Non-Defaulting Company or Companies") reasonably satisfies the Government that it, or they, is/are willing and would be able to carry out the obligations of the Contractor; or

(ii) where the Non-Defaulting Company or Companies have acquired the Participating Interest of the Defaulting Company pursuant to the provisions of the Operating Agreement and have procured and delivered to the Government a performance guarantee or guarantees and a legal opinion or opinions as referred to in Article 30.1 in respect of the share of the Participating Interest of the Defaulting Company acquired by the Non-Defaulting Company or Companies.

31.2 Bankruptcy or Liquidation of Guarantor

This Contract may also be terminated by the Government on giving the requisite notice specified above if the events specified in Article 31.1 (b) and (c) occur with respect to a company which has given a guarantee pursuant to Article 30 subject, however, to Article 31.3.

31.3 Remedy of Default

If the circumstance or circumstances that give rise to the right of termination under Article 31.1(d), (e) or (f) or Article 31.2 are remedied (whether by the Defaulting Company or by another Party or Parties on its behalf) within the ninety (90) day period or such extended period as may be granted by the Government, following the notice of the Government's intention to terminate the Contract as aforesaid, such termination shall not become effective.

31.4 Pending Arbitration

If the circumstance or circumstances that would otherwise result in termination are the subject matter of proceedings under Article 34, then termination shall not take place so long as such proceedings continue and thereafter may only take place when and if consistent with the arbitral award.

31.5 Accrued Obligations Not Affected by Termination

On termination of this Contract, for any reason whatsoever, the rights and obligations of the Contractor shall cease but such termination shall not affect any rights of any Party which may have accrued or any obligations undertaken, or incurred, pursuant to this Contract, by the Contractor or any Party comprising the Contractor and not discharged by the Contractor or the Party prior to the date of termination.

31.6 Continuing Obligations

In the event of termination pursuant to Articles 31.1 or 31.2:

(a) the Government may require the Contractor, for a period not exceeding one hundred and eighty (180) days from the date of termination, to continue, for the account and at the cost of the Government, Crude Oil or Natural Gas production activities until the right to continue such production has been transferred to another entity;

(b) a Foreign Company, which is a constituent of the Contractor, shall, subject to the provisions hereof, have the right to remove and export all its property which has not vested in ONGC provided that in the event that ownership of any property is in doubt, or disputed, such property shall not be exported unless and until the doubt or dispute has been settled in favour of the Foreign Company.

31.7 Contractor to Comply With Article 14.9

Within ninety (90) days after the termination of this Contract pursuant to Article 31.1 or 31.2, or such longer period as the Government may agree, the Contractor shall comply with the applicable provisions of Article 14.9 and any reasonably necessary action as directed by the Government to avoid Environmental Damage or hazards to human life or to the property of others.

31.8 No Liability to Government

Termination of this Contract by the Government in accordance with Articles 31.1 and 31.2 shall not result in any kind of liability whatsoever to the Government.

ARTICLE 32

FORCE MAJEURE

32.1 Non-Performance or Delay Excused

Any non-performance or delay in performance by any Party hereto of any of its obligations under this Contract, or in fulfilling any condition of any licence or lease granted to such Party, or in meeting any requirement of the Act, the Rules or any licence or lease issued thereunder, shall be excused if, and to the extent that, such non-performance or delay in performance is caused by Force Majeure as defined in this Article.

32.2 Force Majeure Events

For the purpose of this Contract, the term Force Majeure means any cause or event, whether similar to or different from those enumerated herein, lying beyond the reasonable control of, and unanticipated or unforeseeable by, and not brought about at the instance of, the Party claiming to be affected by such event, or which, if anticipated or foreseeable, could not be avoided or provided for, and which has caused the non-performance or delay in performance. Without limitation to the generality of the foregoing, the term Force Majeure shall include natural phenomena or calamities, earthquakes, typhoons, fires, wars declared or undeclared, hostilities, invasions, blockades, riots, insurrection and civil disturbances and strikes and lockouts, but shall not include the unavailability of funds except where such unavailability is attributable to acts of the Government.

32.3 Party to Notify Force Majeure Event

Where a Party is claiming suspension of its obligations on account of Force Majeure, it shall promptly, but in no case later than seven (7) days after the occurrence of the event of Force Majeure, notify the other Parties in writing giving full particulars of the Force Majeure, the estimated duration thereof, the obligations affected and the reasons for its suspension.

32.4 Duty to Mitigate Effects of Force Majeure

A Party claiming Force Majeure shall exercise reasonable diligence to seek to overcome the Force Majeure event and to mitigate the effects thereof on the performance of its obligations under this Contract provided, however, that the settlement of strikes or differences with employees shall be within the discretion of the Party having the difficulty. The Party affected shall promptly notify the other Parties as soon as the Force

Majeure event has been removed and no longer prevents it from complying with the obligations which have been suspended and shall thereafter resume compliance with such obligations as soon as possible.

32.5 Onus on Party Claiming Force Majeure

The Party asserting the claim of Force Majeure shall have the burden of proving that the circumstances constitute valid grounds of Force Majeure under this Article and that such Party has exercised reasonable diligence and efforts to remedy the cause of any alleged Force Majeure.

32.6 Extension of Time as a Result of Force Majeure

Where a Party is prevented from exercising any rights or performing any obligations under this Contract due to Force Majeure, the time for the performance of the obligations affected thereby and for performance of any obligation or the exercise of any right dependent thereon, and the term of this Contract may be extended by such additional period as may be agreed between the Parties or, failing agreement, by a sole expert in accordance with Article 34.2.

32.7 Force Majeure Event Exceeds 30 Days

Notwithstanding anything contained hereinabove, if an event of Force Majeure occurs and is likely to continue for a period in excess of thirty (30) days, the Parties shall meet to discuss the consequences of the Force Majeure and the course of action to be taken to mitigate the effects thereof or to be adopted in the circumstances.

ARTICLE 33

APPLICABLE LAW AND LANGUAGE OF THE CONTRACT

33.1 Indian Law to Govern

Subject to the provisions of Article 34.12 this Contract shall be governed and interpreted in accordance with the laws of India.

33.2 Laws of India Not to be Contravened

Subject to Article 17.1 nothing in this Contract shall entitle the Contractor to exercise the rights, privileges and powers conferred upon it by this Contract in a manner which will contravene the laws of India.

ARTICLE 34

SOLE EXPERT, CONCILIATION AND ARBITRATION

34.1 Parties to Use Best Efforts to Settle Disputes

The Parties shall use their best efforts to settle amicably all disputes, differences or claims arising out of or in connection with any of the terms and conditions of this Contract or concerning the interpretation or performance thereof.

34.2 References to Sole Expert

Matters which, by the terms of this Contract, the Parties have agreed to refer to a sole expert and any other matters which the Parties may agree to so refer, shall be referred to an independent and impartial person of international standing with relevant qualifications and experience appointed by agreement between the Parties. Any sole expert appointed shall be acting as an expert and not as an arbitrator and the decision of the sole expert on matters referred to him shall be final and binding on the Parties and not subject to arbitration. If the Parties are unable to agree on a sole expert, the matter may be referred to arbitration.

34.3 Unresolved Disputes

Subject to the provisions of this Contract, the Parties hereby agree that any matter, unresolved dispute, difference or claim which cannot be agreed or settled amicably within twenty one (21) days may be submitted to a sole expert (where Article 34.2 applies) or otherwise to an arbitral tribunal for final decision as hereinafter provided.

34.4 Composition of Arbitral Tribunal and Appointment of Arbitrators

The arbitral tribunal shall consist of three arbitrators. Each Party to the dispute shall appoint one arbitrator. The two arbitrators appointed by the Parties shall appoint the third arbitrator.

34.5 Failure of a Party to Appoint Arbitrator

Any Party may, after appointing an arbitrator, request the other Party(ies) in writing to appoint the second arbitrator. If such other Party fails to appoint an arbitrator within thirty (30) days of receipt of the written request to do so, the second arbitrator may, at the request of the first Party, be appointed by the Secretary General of the Permanent Court of Arbitration at The Hague, within thirty (30) days of the date of

receipt of such request, from amongst persons who are not nationals of the country of any of the Parties to the arbitration proceedings.

34.6 Failure of Arbitrators to Appoint Third Arbitrator

If the two arbitrators appointed by or on behalf of the Parties fail to agree on the appointment of the third arbitrator within fourteen (14) days of the appointment of the second arbitrator and if the Parties do not otherwise agree, the Secretary General of the Permanent Court of Arbitration at The Hague may, at the request of either Party and in consultation with both, appoint the third arbitrator who shall not be a national of the country of any Party.

34.7 Failure of Arbitrator to Act

If any of the arbitrators fails or is unable to act, his successor shall be appointed by the Party or person which originally appointed such arbitrator or as may be otherwise agreed by the Parties to the dispute.

34.8 Decision of Arbitral Tribunal to be Binding

The decision of the arbitral tribunal, and, in the case of difference among the arbitrators, the decision of the majority, shall be final and binding upon the Parties.

34.9 UNCITRAL Rules to Apply

Arbitration proceedings shall be conducted in accordance with the UNCITRAL Model Law on International Commercial Arbitration of 1985 except that in the event of any conflict between these rules and the provisions of this Article 34, the provisions of this Article 34 shall govern.

34.10 Survival of Right to Arbitrate

The right to arbitrate disputes and claims under this Contract shall survive the termination of this Contract.

34.11 Conciliation

Prior to submitting a dispute to arbitration, the Parties may by mutual agreement submit the matter for conciliation under the UNCITRAL conciliation rules by a sole conciliator to be appointed by mutual agreement of the Parties. No arbitration proceedings shall be instituted while conciliation proceedings are pending provided that a Party may initiate arbitration proceedings in the event that the dispute has not been resolved by conciliation within twenty one (21) days of the date of agreement by the Parties to submit such dispute to conciliation.

34.12 Venue and Law of Arbitration Agreement

The venue of sole expert, conciliation or arbitration proceedings pursuant to this Article, unless the Parties otherwise agree, shall be Kuala Lumpur, Malaysia, and shall be conducted in the English language. Insofar as practicable, the Parties shall continue to implement the terms of this Contract notwithstanding the initiation of arbitral proceedings and any pending claim or dispute. Notwithstanding the provisions of Article 33.1, the arbitration agreement contained in this Article 34 shall be governed by the laws of England.

34.13 Fees and Expenses

The fees and expenses of a sole expert or conciliator appointed by the Parties shall be borne equally by the Parties. Assessment of the costs of arbitration including incidental expenses and liability for the payment thereof shall be at the discretion of the arbitrators.

ARTICLE 35

ENTIRE AGREEMENT, AMENDMENTS, WAIVER AND MISCELLANEOUS

35.1 Supersedes Prior Agreements

This Contract supersedes and replaces any previous agreement or understanding between the Parties, whether oral or written, on the subject matter hereof, prior to the Effective Date of this Contract.

35.2 Amendment

This Contract shall not be amended, modified, varied or supplemented in any respect except by an instrument in writing signed by all the Parties, which shall state the date upon which the amendment or modification shall become effective.

35.3 Waiver

No waiver by any Party of any one or more obligations or defaults by any other Party in the performance of this Contract shall operate or be construed as a waiver of any other obligations or defaults whether of a like or of a different character.

35.4 Successors and Assigns

The provisions of this Contract shall inure to the benefit of and be binding upon the Parties and their permitted assigns and successors in interest.

35.5 Conflict Between Contract and Appendices

In the event of any conflict between any provisions in the main body of this Contract and any provision in the Appendices, the provision in the main body shall prevail.

35.6 Headings

The headings of this Contract are for convenience of reference only and shall not be taken into account in interpreting the terms of this Contract.

ARTICLE 36

CERTIFICATES

36.1 Each Party comprising Contractor shall furnish to the Government within fifteen (15) days of the Effective Date of this Contract:

(a) a duly authorised copy of a resolution properly and legally passed by the Board of Directors of such Party authorizing a Director, General Manager, President or any Vice-President, or duly appointed attorney, to execute this Contract along with a certificate duly signed by the Secretary or duly authorised Director of such Party under its seal in this regard and to the effect that such Party has the power and authority to enter into this Contract and to perform its obligations thereunder and has taken all necessary action to authorize the execution, delivery and performance of the Contract; and

(b) a legal opinion from its legal advisors (including a legal advisor who is an employee of the Party), in a form satisfactory to the Government, to the effect that the Contract has been duly signed and delivered on behalf of such Party with due authority and is legally valid and enforceable and binding upon it.

ARTICLE 37

NOTICES

37.1 Manner of Service of Notices and Addresses for Service

All notices, statements, and other communications to be given, submitted or made hereunder by any Party to another shall be sufficiently given if given in writing in the English language, addressed to the member appointed by the receiving Party pursuant to Article 6.2, and delivered by hand, or sent by telex or facsimile transmission, to the address, telex or facsimile number of the other Party or Parties as follows:

(a) If to the Government:

Ministry of Petroleum and Natural Gas
Shastri Bhavan
Dr. Rajendra Prasad Marg
New Delhi 110001
INDIA

Telex No: 031 66235
Facsimile No: 91 11 384 787
Telephone No.: 91 11 386 935

(b) If to ONGC:

Oil and Natural Gas Corporation Ltd
124 Connaught Circus
New Delhi 110001
INDIA

Telex No: 0595 -206
Facsimile No. : 0135-25298
Telephone No.: 91 11 331 0156

(c) If to Videocon:

Videocon Petroleum Limited
429, Som Dutt Chambers - II
4th Floor, Bhikaji Cama Place
New Delhi 110066
INDIA

Telex No: 031 72042
Facsimile No: 91 11 688 5029
Telephone: 91 11 67 1112

with a courtesy copy to:

Mr K R Shenai
Videocon Petroleum Ltd
69, Thirumalai Pillai Rd
T Nagar, Madras, India - 600 017

Telex No.: 014 5005 VICO IW
Facsimile No: 91 44 825 8258

(d) If to Command:

Command Petroleum (India) Pty Ltd
Level 1
191 New South Head Road
Edgecliff NSW 2027

Telex No: AA73792 (Compet)
Facsimile No: 61 2 362 4248
Telephone No: 61 2 362 4233

(e) If to Marubeni:

Ravva Oil (Singapore) Pte Ltd
16 Raffles Quay
40-01A Hong Leong Building
SINGAPORE 0104

Telex No: RS 21900
Facsimile No: 65 221 54 58
Telephone: 65 224 0446

with a courtesy copy to:

Marubeni Corporation
4-2, Ohtemachi 1-Chome
Chiyoda-Ku, Tokyo
JAPAN

Attention: General Manager, Petroleum Development Department
Telex No: J22326
Facsimile No: (03) 3282 9544

37.2 Deemed Receipt of Notices Delivered by Hand

If a notice is delivered by hand during the normal business hours of the intended recipient, it shall be deemed to have been received at the time of delivery, otherwise on the next day that is a Business Day.

37.3 Deemed Receipt of Notices Sent by Facsimile or Telex

Any notice sent by facsimile or telex shall be deemed, in the absence of proof to the contrary, to have been received by the Party to whom it was sent on the date of despatch PROVIDED that:

(i) in the case of a telex:

(aa) the recipient's answerback code appears on the sender's copy of the telex;

(bb) if the time of despatch is not before 5 00pm on a Business Day, it shall be deemed to have been received at the commencement of business on the next Business Day;

(ii) in the case of a facsimile:

(aa) the recipient's facsimile number or answerback code appears on the sender's transmission report;

(bb) if the time of despatch is not before 5.00pm on a Business Day, it shall be deemed to have been received at the commencement of business on the next Business Day.

37.4 Notices Signed by Officer, Manager or Authorised Representative

Any notice required to be made or given hereunder may be signed by an officer, manager or authorised representative of the Party giving or making the same No recipient shall be concerned to inquire as to the authority of the officer, manager or authorised representative so signing.

37.5 Change of Address For Service

Any Party may, by notice to the other Parties, change its address, telex or facsimile number for the purposes of this Article 37

37.6 Courtesy Copy of Notices

For the avoidance of doubt, the Parties agree that:

(i) no Party shall be required to prove service of a courtesy copy of a notice; and

(ii) the failure to receive such copy shall not invalidate any notice.

IN WITNESS WHEREOF, the representatives of the Parties to this Contract being duly authorised have hereunto set their hands and have executed these presents this .....28th.....day of October.1994

Signed for and on behalf of the President of India

By: ..20.10.94.

in the presence of:

V. Ramani

Signed for and on behalf of Oil and Natural Gas Corporation Limited

By: ..20.10.94

in the presence of:

28.10.1994

Signed for and on behalf of Videocon Petroleum Limited

By:

in the presence of

Signed for and on behalf of Command Petroleum (India) Pty Ltd

By:

in the presence of:

Signed for and on behalf of Ravva Oil (Singapore) Pte Ltd

By:

in the presence of:

28/10/94

APPENDIX A

DESCRIPTION OF CONTRACT AREA

The area comprising approximately 331.26 Sq.Km. Offshore India identified as Ravva Oil & Gas Field described herein and shown under map attached as Appendix B.

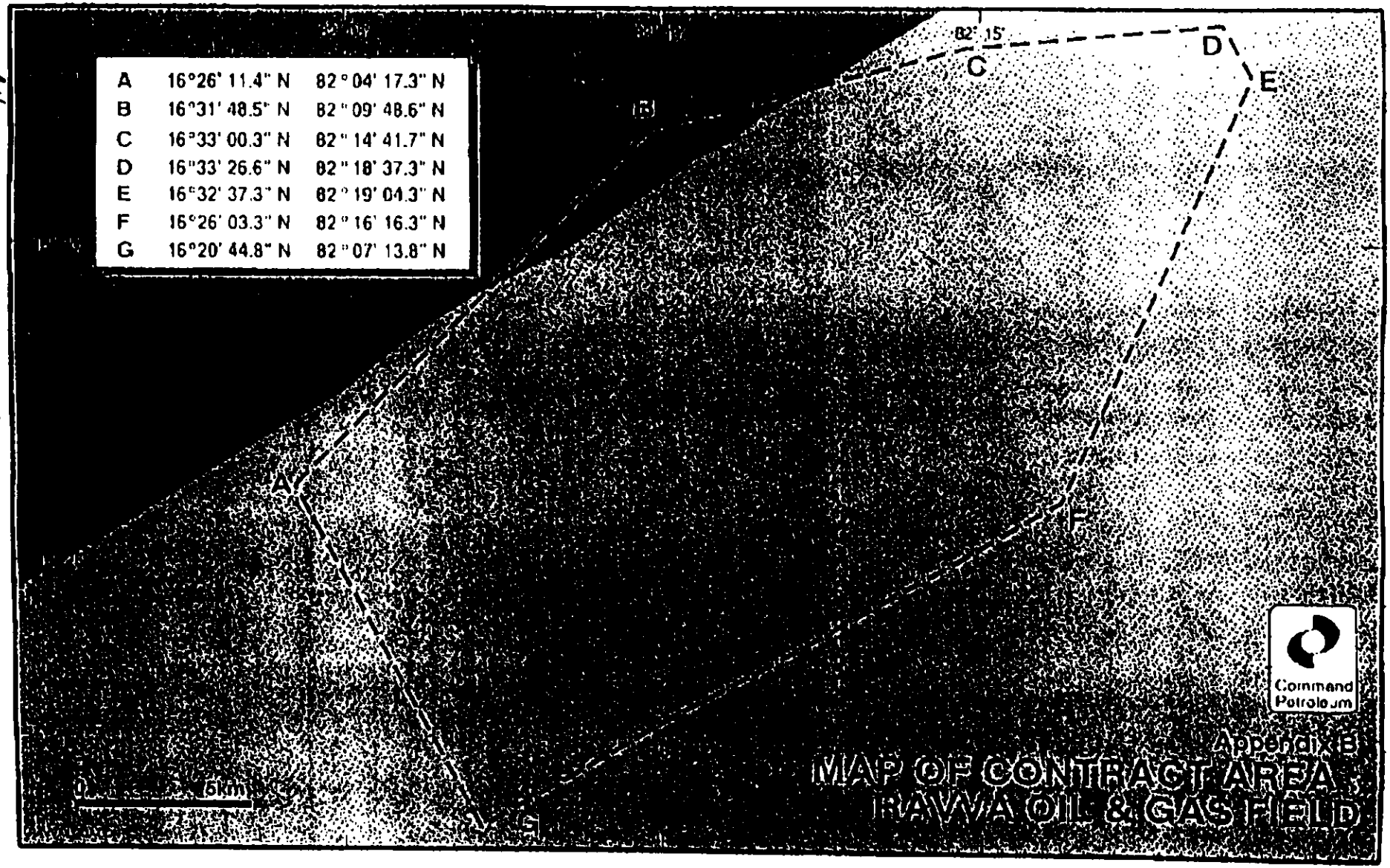
Longitude and Latitude measurements commencing at point A are as follows.

Point	Latitude	Longitude
A	16°26'11.4"N	82°04'17.3"E
B	16°31'48.5"N	82°09'48.6"E
C	16°33'00.3"N	82°14'41.7"E
D	16°33'26.6"N	82°18'37.3"E
E	16°32'37.3"N	82°19'04.3"E
F	16°26'03.3"N	82°16'16.3"E
G	16°20'44.8"N	82°07'13.8"E

APPENDIX C

ACCOUNTING PROCEDURE

(ARTICLE 1.1)


A 16°26' 11.4" N 82° 04' 17.3" N
B 16°31' 48.5" N 82° 09' 48.6" N
C 16°33' 00.3" N 82° 14' 41.7" N
D 16°33' 26.6" N 82° 18' 37.3" N
E 16°32' 37.3" N 82° 19' 04.3" N
F 16°26' 03.3" N 82° 16' 16.3" N
G 16°20' 44.8" N 82° 07' 13.8" N
82° 15'
A
B
C
D
E
F
G
0
6km
Command Petroleum
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RAVVA OIL & GAS FIELD

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ACCOUNTING PROCEDURE

SECTION 1

GENERAL PROVISIONS

1.1 Purpose

Generally, the purpose of this Accounting Procedure is to set out principles and procedures of accounting which will enable the Government of India to monitor effectively the Contractor's costs, expenditures, production and income so that the Government's entitlement to Profit Petroleum, Royalty, Cess , and Gas as well as, when appropriate, ONGC's entitlement to Cost Petroleum and Profit Petroleum can be accurately determined pursuant to the terms of the Contract. More specifically, the purpose of the Accounting Procedure is to:

- classify costs and expenditures and to define which costs and expenditures shall be allowable for cost recovery, production sharing and participation purposes;
- specify the manner in which the Contractor's accounts shall be prepared and approved; and
- address numerous other related accounting matters.

This Accounting Procedure is intended to apply to the provisions of the Contract and is without prejudice to the computation of income tax under applicable provisions of the Income-Tax Act, 1961, as amended.

1.2 Definitions

For purposes of this Accounting Procedure, the terms used herein which are defined in the Contract shall have the same meaning when used in this Accounting Procedure.

1.3 Inconsistency

In the event of any inconsistency or conflict between the provisions of this Accounting Procedure and the other provisions of the Contract, the other provisions of the Contract shall prevail.

1.4 Documentation and Statements to be Submitted by the Contractor

1.4.1 Within thirty (30) days of the Effective Date of the Contract, the Contractor shall submit to and discuss with the Government a proposed outline of charts of

accounts, operating records and reports, which outline shall reflect each of the categories and sub-categories of costs and income specified in Sections 2 and 3 and shall be in accordance with generally accepted standards and recognized accounting systems and consistent with international petroleum industry practice and procedures for joint venture operations.

Within ninety (90) days of receiving the above submission, the Government shall either provide written notification of its approval of the proposal or request, in writing, revisions to the proposal.

Within one hundred and eighty (180) days from the Effective Date of the Contract, the Contractor and the Government shall agree on the outline of charts of accounts, records and reports which shall also describe the basis of the accounting system and procedures to be developed and used under this Contract. Following such agreement, the Contractor shall expeditiously prepare and provide the Government with formal copies of the comprehensive charts of accounts, records and reports and allow the Government to examine the manuals and to review procedures which are, and shall be, observed under the Contract.

1.4.2 Notwithstanding the generality of the foregoing, the Contractor shall make regular Statements relating to the Petroleum Operations as follows:

(i) Production Statement and Royalty and Cess Statement (see Section 5 of this Accounting Procedure).
(ii) Value of Production and Pricing Statement (see Section 6 of this Accounting Procedure).
(iii) Statement of Costs, Expenditures and Receipts (see Section 7 of this Accounting Procedure).
(iv) Cost Recovery Statement (see Section 8 of this Accounting Procedure).
(v) Production Sharing Statement (see Section 9 of this Accounting Procedure)
(vi) End of Year Statement (see Section 10 of this Accounting Procedure).
(vii) Budget Statement (see Section 11 of this Accounting Procedure).

1.4.3 All reports and Statements shall be prepared in accordance with the Contract and the laws of India and, where there are no relevant provisions in either of these, in accordance with generally accepted practices in the international petroleum industry.

1.4.4 Each of the entities constituting the Contractor shall be responsible for maintaining its own accounting records in order to comply with all legal requirements

and to support all returns or any other accounting reports required by any Government authority in relation to the Petroleum Operations. However, for the purposes of giving effect to this Accounting Procedure, the Operator shall be responsible for maintaining, at its business office in India, on behalf of the Contractor, all the accounts of the Petroleum Operations in accordance with the provisions of the Accounting Procedure and the Contract.

1.5 Language and Units of Account

All accounts, records, books, reports and Statements shall be maintained and prepared in the English language. The accounts shall be maintained in United States Dollars, which shall be the controlling currency of account for cost recovery, production sharing and participation purposes. Metric units and Barrels shall be employed for measurements required under the Contract. Where necessary for clarification, the Contractor may also maintain accounts and records in other languages, currencies and units.

1.6 Currency Exchange Rates

1.6.1 For conversion purposes between United States and Indian Rupees or any other currency, the monthly average of the daily mean of the buying and selling rates of exchange quoted by the State Bank of India, unless otherwise agreed between the Parties for the Month in which the revenues, costs, expenditures, receipts or income are recorded, shall be used. However, in the case of any single non-US Dollar transaction in excess of the equivalent of fifty thousand (50,000) US Dollars , the conversion into US Dollars shall be performed on the basis of the average of the applicable exchange rates for the day on which the transaction occurred. The provisions of paragraph 2 of Article I of the JOA Accounting Procedure shall apply for the purposes of reporting transactions under the Operating Agreement.

1.6.2 Any realized or unrealized gains or losses from the exchange of currency in respect of Petroleum Operations shall be credited or charged to the accounts. A record of the exchange rates used in converting Indian Rupees or any other currencies into United States Dollars as specified in Section 1.6.1 shall be maintained by the Contractor and shall be identified in the relevant Statements required to be submitted by the Contractor in accordance with Section 1.4.2.

1.7 Payments

1.7.1 Subject to the foreign exchange laws and regulations prevailing from time to time, all payments between the Parties shall, unless otherwise agreed, be in United States Dollars and shall be made through a bank designated by each receiving Party.

1.7.2 Unless otherwise specified, all sums due under the Contract shall be paid within forty five (45) days from the date on which the obligation to pay was incurred.

1.7.3 All sums due by one Party to the other under the Contract during any Month shall, for each day such sums are overdue during such Month, bear interest compounded daily at the applicable LIBOR plus two (2) percentage points.

1.8 Arms Length Transactions

Unless otherwise specifically provided for in the Contract, all transactions giving rise to revenues, costs or expenditures which will be credited or charged to the accounts prepared, maintained or submitted hereunder shall be conducted at arms length or on such a basis as will assure that all such revenues, costs or expenditures will not be lower or higher, as the case may be, than would result from a transaction conducted at arms length on a competitive basis with third parties.

1.9 Audit and Inspection Rights of the Government

1.9.1 Without prejudice to statutory rights, the Government, upon at least fifteen (15) days advance written notice to the Contractor, shall have the right to inspect and audit, during normal business hours, all records and documents supporting costs, expenditures, expenses, receipts and income, such as Contractor's accounts, books, records, invoices, cash vouchers, debit notes, price lists or similar documentation with respect to the Petroleum Operations conducted hereunder in each Year, within two (2) years (or such longer period as may be required in exceptional circumstances) from the end of such Year.

1.9.2 The Government may undertake the conduct of the audit either through its own representatives or through a qualified firm of recognised chartered accountants, registered in India, appointed for the purpose by the Government and the costs of such audit shall be borne by the Contractor as a General and Administrative Cost.

1.9.3 In conducting the audit, the Government or its auditors shall be entitled to examine and verify, at reasonable times, all charges and credits relating to Contractor's activities under the Contract and all books of account, accounting entries, material records and inventories, vouchers, payrolls, invoices and any other documents, correspondence and records considered necessary by the Government to audit and verify the charges and credits. The auditors shall also have the right, in connection with such audit, to visit and inspect, at reasonable times, all sites, plants, facilities, warehouses and offices of the Contractor directly or indirectly serving the Petroleum Operations, and to physically examine other property, facilities and stocks used in Petroleum Operations, wherever located and to question personnel associated with those operations. Where the Government requires verification of charges made by an Affiliate, the Government shall have the right to obtain an audit certificate from an internationally recognized firm of public accountants acceptable to both the Government and the Contractor, which may be the Contractor's statutory auditor.

1.9.4 Any audit exceptions shall be made by the Government in writing and notified to the Contractor within one hundred and twenty (120) days following completion of the audit in question.

1.9.5 The Contractor shall answer any notice of exception under Section 1.9.4 within one hundred and twenty (120) days of the receipt of such notice. Where the Contractor has, after the said one hundred and twenty (120) days, failed to answer a notice of exception, the exception shall prevail.

1.9.6 All agreed adjustments resulting from an audit and all adjustments required by prevailing exceptions shall be promptly made in the Contractor's accounts and any consequential adjustments to the Government's or its nominee's entitlement to Petroleum shall be made as promptly as practicable.

1.9.7 If the Contractor and the Government are unable to reach final agreement on proposed audit adjustments, either Party may refer any dispute thereon to a sole expert as provided for in the Contract. So long as any issues are outstanding with respect to an audit, the Contractor shall maintain the relevant documents and permit inspection thereof until the issue is resolved.

1.10 <u>Revision of the Accounting Procedure</u>

1.10.1 By mutual agreement between the Government and the Contractor, this Accounting Procedure may be revised from time to time, in writing, signed by the Parties.

stating the date upon which the amendments shall become effective.

1.10.2 Following any New Discovery of Petroleum in the Contract Area, the Parties shall meet in order to establish specific principles and procedures for identifying all costs, expenditures, receipts and income, with respect to the Contract Area.

SECTION 2

CLASSIFICATION, DEFINITION AND ALLOCATION OF COSTS AND EXPENDITURES

2.1 Segregation of Costs

Costs shall be segregated in accordance with the purposes for which such expenditures are made. All costs and expenditures allowable under Section 3, relating to Petroleum Operations, shall be classified, defined and allocated as set out below in this Section.

2.2 Exploration Costs

Exploration Costs are all direct and allocated indirect expenditures incurred in the search for Petroleum in an area which is, or was at the time when such costs were incurred, part of the Contract Area, including expenditures incurred in respect of:

2.2.1 Aerial, geophysical, geochemical, palaeontological, geological, topographical and seismic surveys, analyses and studies and their interpretation.

2.2.2 Core hole drilling and water Well drilling.

2.2.3 Labour, materials, supplies and services used in drilling Wells with the object of finding Petroleum or in drilling Appraisal Wells provided that if such Wells are completed as producing Wells, the costs of completion thereof shall be classified as Development Costs.

2.2.4 Facilities used solely in support of the purposes described in Sections 2.2.1, 2.2.2 and 2.2.3 above, including access roads, all separately identified.

2.2.5 Any Service Costs and General and Administrative Costs directly incurred on exploration activities and identifiable as such and a portion of the remaining Service Costs and General and Administrative Costs allocated to Exploration Operations determined by the proportionate share of total Contract Costs (excluding General and Administrative Costs and Service Costs) represented by all other Exploration Costs.

2.2.6 Geological and geophysical information purchased or acquired in connection with Exploration Operations.

2.2.7 Any other expenditures incurred in the search for Petroleum not covered under Sections 2.3 or 2.4 including relevant Site Restoration costs and environmental protection costs.

2.3 Development Costs

Development Costs are all direct and allocated indirect expenditures incurred with respect to the development of a Field in the Contract Area including expenditures incurred on account of:

2.3.1 Drilling Development Wells, whether these Wells are dry or producing and drilling Wells for the injection of water or Gas to enhance recovery of Petroleum.

2.3.2 Completing of Exploration Wells by way of installation of casing or equipment or otherwise or for the purpose of bringing a Well into use as a producing Well or as a Well for the injection of water or Gas to enhance recovery of Petroleum.

2.3.3 Purchase, installation or construction of production, transport and storage facilities for production of Petroleum from a Field, such as pipelines, flow lines, production and treatment units, wellhead equipment, subsurface equipment, enhanced recovery systems, offshore and onshore platforms, export terminals and piers, harbours and related facilities and access roads for production activities.

2.3.4 Geological, engineering and design studies for facilities referred to in Section 2.3.3 including, up to US$300,000 for those necessary for the preparation of the Ravva Development Plan.

2.3.5 Any Service Costs and General and Administrative Costs directly incurred in Development Operations and identifiable as such and a portion of the remaining Service Costs and General and Administrative Costs allocated to development activities, determined by the proportionate share of total Contract Costs (excluding General and Administrative Costs and Service Costs) represented by all other Development Costs.

2.4 Production Costs

Production Costs are expenditures incurred on Production Operations in respect of a Field in the Contract Area after the start of production from the Field including environmental protection costs and provision for Site Restoration costs and costs necessary to deliver Petroleum to the Delivery Point (which are other than Exploration and Development Costs). The balance of General and Administrative Costs and Service Costs not allocated to Exploration Costs or Development Costs shall be allocated to Production Costs.

2.5 Service Costs

Service Costs are direct and indirect expenditures incurred in support of Petroleum Operations including expenditures on warehouses, piers, marine vessels, vehicles, motorized rolling equipment, aircraft, fire and security stations, workshops, water and sewerage plants, power plants, housing, community and recreational facilities and furniture and tools and equipment used in these activities. Service Costs in any Year shall include the costs incurred in such Year to purchase and/or construct the said facilities as well as the annual costs of maintaining and operating the same, each to be identified separately. All Service Costs shall be regularly allocated as specified in Sections 2.2.5, 2.3.5 and 2.4 to Exploration Costs, Development Costs and Production Costs and shall be separately shown under each of these categories. Where Service Costs are made in respect of shared facilities, the basis of allocation of costs to Petroleum Operations hereunder shall be specified.

2.6 General and Administrative Costs

General and Administrative Costs are expenditures incurred on general administration and management primarily and principally related to Petroleum Operations and shall include:

2.6.1 main office, field office and general administrative expenditures whether in India or elsewhere including supervisory, accounting and employee relations services; and

2.6.2 an overhead charge, to be charged on a monthly basis, for services rendered by the parent company or an Affiliate of the Operator outside India to support and manage Petroleum Operations under the Contract, and for staff advice and assistance including financial, legal, accounting and employee relations services, but excluding any remuneration for services charged separately under this Accounting Procedure, at the rate of 1% of total Contract Costs (excluding Royalty, Cess and any other applicable Government levies referred to in Article 17) incurred and qualifying for recovery pursuant to Section 3.

2.6.3 All General and Administrative Costs shall be regularly allocated as specified in Sections 2.2.5, 2.3.5 and 2.4 to Exploration Costs, Development Costs and Production Costs respectively, and shall be separately shown under each of these cost categories.

2.7 For the avoidance of doubt, costs incurred by the Operator in carrying out its duties under the Contract on behalf of the Contractor shall be deemed to be costs of the Contractor.

SECTION 3

COSTS, EXPENSES, EXPENDITURES AND INCIDENTAL INCOME OF THE CONTRACTOR

3.1 Costs Recoverable and Allowable Without Further Approval of the Government

Costs incurred by the Contractor on Petroleum Operations pursuant to the Contract shall be allowable for the purposes of the Contract except to the extent provided in Section 3.2 or elsewhere in this Accounting Procedure, and subject to audit as provided for herein.

3.1.1 Surface Rights

All direct costs necessary for the acquisition, renewal or relinquishment of surface rights acquired and maintained in force for the purposes of the Contract except as provided in Section 3.1.9.

3.1.2 Labour and Associated Labour Costs of Contractor's Locally Recruited Employees Based in India and Assigned Personnel

(a) Locally Recruited Employees

Costs of all Contractor's locally recruited employees who are directly engaged in the conduct of Petroleum Operations under the Contract in India. Such costs shall include the costs of employee benefits and Government benefits for employees and levies imposed on the Contractor as an employer, transportation and relocation costs within India of the employee and such members of the employee's family (limited to spouse and dependent children) as required by law or customary practice in India. If such employees are engaged in other activities in India, in addition to Petroleum Operations, the cost of such employees shall be apportioned on a time sheet basis according to sound and acceptable accounting principles.

(b) Assigned Personnel

Costs of salaries and wages, including bonuses, of the Contractor's employees directly and necessarily engaged in the conduct of the Petroleum Operations under the Contract, whether temporarily or permanently assigned, irrespective of the location of such employees, it being understood that in the

case of those personnel only a portion of whose time is wholly dedicated to Petroleum Operations under the Contract, only that pro rata portion of applicable salaries, wages, and other costs, as specified in Sections 3.1.2(c), (d), (e), (f) and (g), shall be charged and the basis of such pro rata allocation shall be specified.

(c) The Contractor's costs regarding holiday, vacation, sickness and disability benefits and living and housing and other customary allowances applicable to the salaries and wages chargeable under Section 3.1.2(b) above.

(d) Expenses or contributions made pursuant to assessments or obligations imposed under the laws of India which are applicable to the Contractor's cost of salaries and wages chargeable under Section 3.1.2(b) above.

(e) The Contractor's cost of established plans for employees' group life insurance, hospitalization, pension, retirement and other benefit plans of a like nature customarily granted to the Contractor's employees provided, however, that such costs are in accordance with generally accepted standards in the international petroleum industry, applicable to salaries and wages chargeable to Petroleum Operations under Section 3.1.2(b) above.

(f) Personal income taxes where and when they are paid by the Contractor to the Government of India for the employee, in accordance with the Contractor's standard personnel policies.

(g) Reasonable transportation and travel expenses of employees of the Contractor, including those made for travel and relocation of the expatriate employees, including their dependent family and personal effects, assigned to Petroleum Operations whose salaries and wages are chargeable to Petroleum Operations under Section 3.1.2(b) above. Actual transportation expenses of personnel transferred to Petroleum Operations shall be charged to the Petroleum Operations. Transportation cost as used in this Section shall mean the cost of freight and passenger service and any accountable incidental expenditures related to transfer travel and authorised under Contractor's standard personnel policies. Contractor shall ensure that all expenditures related to

transportation costs are equitably allocated to the activities which have benefited from the personnel concerned.

3.1.3 Transportation Costs

The reasonable cost of transportation of equipment, materials and supplies within India and from outside India to India necessary for the conduct of Petroleum Operations under the Contract, including directly related costs such as unloading charges, dock fees and inland and ocean freight charges.

3.1.4 Charges for Services

(i) Third Parties

The actual costs of contract services, services of professional consultants, utilities and other services necessary for the conduct of Petroleum Operations under the Contract performed by third parties other than an Affiliate of the Contractor, provided that the transactions resulting in such costs are undertaken pursuant to Section 1.8 of this Accounting Procedure.

(ii) Affiliates of Contractor

a) Professional and Administrative Services and Expenses

Cost of professional and administrative services provided by any Affiliate of the Contractor for the direct benefit of Petroleum Operations, including, but not limited to, services provided by the production, exploration, legal, financial, insurance, accounting and computer services divisions other than those covered by Section 3.1.4 (ii)(b) which Operator may use in lieu of having its own employees. Charges shall be equal to the actual cost of providing their services, shall not include any element of profit and shall not be any higher than the most favourable prices charged by the Affiliate to third parties for comparable services under similar terms and conditions elsewhere and will be fair and reasonable in the light of prevailing international oil industry practice and experience.

b) Scientific or Technical Personnel

Cost of scientific or technical personnel services provided by any Affiliate of Contractor for the direct benefit of Petroleum Operations, which cost shall be charged on a cost of service basis. Charges therefor shall not exceed charges for comparable services currently provided by outside technical service organizations of comparable qualifications. Unless the work to be done by such personnel is covered by an Approved Budget and Work Programme, Operator shall not authorize work by such personnel without approval of the Management Committee.

c) Equipment, Facilities and Property of Affiliates

Equipment, facilities and property owned and furnished by the Contractor's Affiliates, at rates commensurate with the cost of ownership and operation provided, however, that such rates shall not exceed those currently prevailing for the supply of like equipment, facilities and property on comparable terms in the area where the Petroleum Operations are being conducted. The equipment and facilities referred to herein shall exclude major investment items such as (but not limited to) drilling rigs, producing platforms, oil treating facilities, oil and gas loading and transportation systems, storage and terminal facilities and other major facilities, rates for which shall be subject to separate agreement with the Management Committee.

3.1.5 Communications

Cost of acquiring, leasing, installing, operating, repairing and maintaining communication systems including radio and microwave facilities between the Contract Area and the Contractor's nearest base facility at Madras, India and head office in Sydney, Australia.

3.1.6 Office, Shore Bases and Miscellaneous Facilities

Net cost to Contractor of establishing, maintaining and operating any office, sub-office, shore base

facility, warehouse, housing or other facility directly serving the Petroleum Operations. If any such facility services contract areas other than the Contract Area, or any business other than Petroleum Operations, the net costs thereof shall be allocated on an equitable and consistent basis.

3.1.7 Environmental Studies and Protection

Costs incurred pursuant to Article 14 of the Contract.

3.1.8 Materials and Equipment

(i) General

So far as is practicable and consistent with efficient and economical operation, only such material shall be purchased or furnished by the Contractor for use in the Petroleum Operations as may be required for use in the reasonably foreseeable future and the accumulation of surplus stocks shall be avoided. Material and equipment held in inventory shall only be charged to the accounts when such material is removed from inventory and used in Petroleum Operations. Costs shall be charged to the accounting records and books based on the "First in, First Out" (FIFO) method.

(ii) Warranty

In the case of defective material or equipment, any adjustment received by the Contractor from the suppliers or manufacturers or their agents in respect of any warranty on material or equipment shall be credited to the accounts under the Contract.

(iii) Value of materials charged to the accounts under the Contract

(a) Except as otherwise provided in subparagraph (b) below, materials purchased by the Contractor for use in the Petroleum Operations shall be valued to include invoice price (less trade and cash discounts, if any) purchase and procurement fees plus freight and forwarding charges between point of supply and point of shipment, freight to port of destination, insurance, taxes, custom duties, consular fees, other items chargeable against imported material and, where applicable, handling and transportation costs from point of

importation to warehouse or operating site, and these costs shall not exceed those currently prevailing in normal arms length transactions on the open market.

(b) Material purchased from or sold to Affiliates or transferred to or from activities of the Contractor other than Petroleum Operations under the Contract:

(aa) new material (hereinafter referred to as condition A) shall be valued at the current international price which shall not exceed the price prevailing in normal arms length transactions on the open market;

(bb) used material which is in sound and serviceable condition and is suitable for reuse without reconditioning (hereinafter referred to as condition B) shall be priced at not more than seventy five percent (75%) of the current price of the above mentioned new materials;

(cc) used material which cannot be classified as condition B, but which, after reconditioning, will be further serviceable for original function as good second-hand condition B material or is serviceable for original function, but substantially not suitable for reconditioning (hereinafter referred to as condition C) shall be priced at not more than fifty percent (50%) of the current price of the new material referred to above as condition A.

The cost of reconditioning shall be charged to the reconditioned material, provided that the condition C material value plus the cost of reconditioning does not exceed the value of condition B material.

Material which cannot be classified as condition B or condition C shall be priced at a value commensurate with its use.

When the use of material is temporary and its service to the Petroleum Operations does not justify the reduction in price in relation to materials referred to above as conditions B and C, such material shall be priced on a basis that will result in a net charge to the accounts under the Contract consistent with the value of the service rendered.

3.1.9 Duties Fees and Other Charges

Any duties, levies, fees, charges and any other assessments levied by any governmental or taxing authority in connection with the Contractor's activities under the Contract and paid directly by the Contractor except:

(i) corporate income tax payable by the constituents of the Contractor; and

(ii) payments paid by the Companies as provided for in Article 18.1.

3.1.10 Insurance and Losses

Insurance premia and costs incurred for insurance pursuant to Article 25 of the Contract, provided that such insurance is customary, affords prudent protection against risk and is at a premium no higher than that charged on a competitive basis by insurance companies which are not Affiliates. Except as provided in Sections 3.2 (ix), Section 3.2(x) and Section 3.2(xi), actual costs and losses incurred shall be allowable. Such costs may include, but are not limited to, repair and replacement of property in the Contract Area resulting from damages or losses incurred by fire, flood, storm, theft, accident or such other cause.

3.1.11 Legal Expenses

All reasonable costs and expenses resulting from the handling, investigating, asserting, defending, or settling of any claim or legal action necessary or expedient for the procuring, perfecting, retention and protection of the Contract Area and in defending or prosecuting lawsuits involving the Contract Area or any third party claim arising out of Petroleum Operations under the Contract, or sums paid in respect of legal services necessary for the protection of the joint interest of Government and the Contractor, shall be allowable. Such expenditures shall include attorney's fees, court costs, costs of investigation and procurement of evidence and amounts paid in

settlement or satisfaction of any such litigation and claims provided such costs are not covered elsewhere in the Accounting Procedure. Where legal services are rendered in such matters by salaried or regularly retained lawyers of the Contractor or an Affiliate, such compensation shall be included instead under Section 3.1.2 or 3.1.4 (ii) above as applicable.

3.1.12 General and Administrative Costs

The costs described in Section 2.6.1 and the charge described in Section 2.6.2 of this Accounting Procedure.

3.1.13 Transportation of Petroleum

All costs incurred in transporting Petroleum to the Delivery Point.

3.2 Costs not recoverable and not allowable under the Contract

The following costs and expenses shall not be recoverable or allowable (whether directly as such or indirectly as part of any other charges or expense) for cost recovery and production sharing purposes under the Contract:

(i) costs and charges incurred before the Effective Date including costs in respect of preparation, signature or ratification of this Contract except as otherwise provided in Section 3.3 of this Accounting Procedure;

(ii) expenditures in respect of any financial transaction to negotiate, float or otherwise obtain or secure funds for Petroleum Operations including, but not limited to, interest, commission, brokerage and fees related to such transactions, as well as exchange losses on loans or other financing, whether between Affiliates or otherwise;

(iii) costs of marketing or transportation of Petroleum beyond the Delivery Point;

(iv) expenditures incurred in obtaining, furnishing and maintaining the guarantees required under the Contract and any other amounts spent on indemnities with regard to non-fulfilment of contractual obligations;

(v) attorney's fees and other costs and charges in connection with arbitration proceedings and sole expert determination pursuant to the Contract;

(vi) fines and penalties imposed by Courts of law of the Republic of India;

(vii) donations and contributions;

(viii) creation of any partnership or joint venture arrangement;

(ix) amounts paid with respect to non-fulfilment of contractual obligations;

(x) costs incurred as a result of failure to insure where insurance is required pursuant to the Contract, or where Contractor has elected to self insure, or has under-insured;

(xi) costs and expenditures incurred as a result of Gross Negligence of the Contractor;

(xii) any costs and expenditures which by reference to general oil industry practices can be shown to be excessive;

(xiii) costs referred to in Article 10.11 and 10.12 of the Contract except in the circumstances therein specified;

(xiv) payments under Article 18.1 of the Contract.

3.3 Other costs recoverable and allowable only with Government Approval

Any other costs and expenditures not included in Section 3.1 or 3.2 of this Accounting Procedure but which have been incurred by the Contractor for the necessary and proper conduct of Petroleum Operations shall be allowed to be recovered only with the express prior approval in writing of the Management Committee PROVIDED THAT:-

(i) the costs referred to in Section 2.3.4 in relation to the Ravva Development Plan incurred prior to the Effective Date; and

(ii) the costs reasonably incurred by Operator during the period between 24 August, 1994 and the Effective Date:-

(aa) in obtaining information and data from ONGC and holding discussions with ONGC personnel regarding same, to enable Operator to assume and perform its obligations as Operator on and from the Effective Date;

(bb) in mobilising personnel for the purpose of Petroleum Operations; and

(cc) in setting up its Madras office.

as approved by the Management Committee, shall be allowed, provided all such costs are covered within the Contractor's Base Development Costs referred to in Article 15.5.

3.4 Incidental Income and Credits

All incidental income and proceeds received from Petroleum Operations under the Contract, including but not limited to the items listed below, shall be credited to the accounts under the Contract and shall be taken into account for cost recovery, production sharing and participation purposes in the manner described in Articles 15 and 16 of the Contract:

(i) The proceeds of any insurance or claim or judicial awards in connection with Petroleum Operations under the Contract or any assets charged to the accounts under the Contract where such operations or assets have been insured and the premia charged to the accounts under the Contract;

(ii) Revenue received from third parties for the use of property or assets, the cost of which has been charged to the accounts under the Contract;

(iii) Any adjustment received by the Contractor from the suppliers/manufacturers or their agents in connection with defective material, the cost of which was previously charged by the Contractor to the accounts under the Contract;

(iv) Rentals, refunds or other credits received by the Contractor which apply to any charge which has been made to the accounts under the Contract;

(v) Proceeds received from sale of materials not used in Petroleum Operations;

(vi) Proceeds from the sale or exchange by the Contractor of plant or facilities from a Field, the acquisition costs of which have been charged to the accounts under the Contract for the relevant Field;

(vii) Proceeds from the sale or exchange by the Contractor of any Petroleum rights, being an interest in the Contract Area but not

including proceeds or other consideration received by a Party comprising the Contractor in respect of the assignment of part or all of such Party's Participating Interest.

(viii) Legal costs charged to the accounts under Section 3.1.11 of this Accounting Procedure and subsequently recovered by the Contractor.

3.5 Non-Duplication of Charges and Credits

Notwithstanding any provision to the contrary in this Accounting Procedure, it is the intention that there shall be no duplication of charges or credits to the accounts under the Contract.

SECTION 4

RECORDS AND INVENTORIES OF ASSETS

4.1 Records

4.1.1 The Contractor shall keep and maintain detailed records of property and assets in use for or in connection with Petroleum Operations under the Contract in accordance with normal practices in exploration and production activities of the international petroleum industry. Such records shall include information on quantities, location and condition of such property and assets, and whether such property or assets are leased or owned.

4.1.2 The Contractor shall furnish particulars to the Government, by notice in writing as provided in the Contract, at six monthly intervals of all assets acquired by the Contractor to be used for or in connection with Petroleum Operations during the period immediately preceding the delivery of such notice.

4.2 Inventories

4.2.1 The Contractor shall:

(a) not less than once every twelve (12) Months with respect to movable assets; and

(b) not less than once every three (3) Years with respect to immovable assets, take an inventory of the assets used for or in connection with Petroleum Operations in terms of the Contract and address and deliver such inventory to the Government together with a written statement of the principles upon which valuation of the assets mentioned in such inventory has been based.

4.2.2 The Contractor shall give the Government at least thirty (30) days notice in writing in the manner provided for in the Contract of its intention to take the inventory referred to in Section 4.2.1 and the Government shall have the right to be represented when such inventory is taken.

4.2.3 When an assignment of rights under the Contract takes place, a special inventory shall be taken by the Contractor at the request of the assignee provided that the cost of such inventory is borne by the assignee and paid to the Contractor.

4.2.4 In order to give effect to Article 28 of the Contract, the Contractor shall provide the Government with a

comprehensive list of all relevant assets when requested by the Government to do so.

SECTION 5

PRODUCTION STATEMENT AND ROYALTY AND CESS STATEMENT

5.1 From the date of first production, after the Effective Date, of Petroleum from the Contract Area, the Contractor shall submit a monthly Production Statement to Government showing the following information separately for each producing Field and in aggregate for the Contract Area:

5.1.1 The quantity of Crude Oil and Condensate produced and saved.

5.1.2 The quality and characteristics of such Crude Oil and Condensate produced and saved.

5.1.3 The quantity of Associated Natural Gas and Non Associated Natural Gas produced and saved.

5.1.4 The quality, characteristics and composition of such Natural Gas produced and saved.

5.1.5 The quantities of Crude Oil, Condensate and Natural Gas used for the purposes of carrying on drilling and production operations and pumping to field storage, as well as quantities reinjected.

5.1.6 The quantities of Crude Oil, Condensate and Natural Gas unavoidably lost.

5.1.7 The quantities of Natural Gas flared and vented.

5.1.8 The size of Petroleum stocks held on the first day of the Month in question.

5.1.9 The size of Petroleum stocks held on the last day of the Month in question.

5.1.10 The quantities of Natural Gas reinjected into the Petroleum Reservoir.

5.1.11 The number of days in the Month during which Petroleum was produced from each Field.

5.1.12 The Gas/Oil ratio for each Field for the relevant Month.

5.1.13 The water/oil ratio for each Field for the relevant Month.

5.2 All quantities shown in this Statement shall be expressed in both volumetric terms (barrels of oil and cubic metres of gas) and in weight (metric tonnes).

5.3 The Government may direct in writing that the Contractor include other particulars relating to the production of Petroleum in its monthly Production Statement, and the Contractor shall comply with such direction.

5.4 The Production Statement for each Month shall be submitted to Government no later than ten (10) days after the end of such Month.

5.5 The Contractor shall, for the purposes of Article 18, submit a statement to Government providing the calculation of the amount of Royalty and Cess, separately, paid with respect to each Calendar Month for each producing Field and in aggregate for the Contract Area. The statement shall show the following information:

5.5.1 The quantity of Crude Oil and Condensate produced and saved.

5.5.2 The quantity of ANG and NANG produced and saved.

5.5.3 The amount of Royalty and Cess, separately, paid on Crude Oil and Condensate produced and saved and the particulars of the calculation thereof.

5.5.4 The amount of Royalty and Cess, separately, paid on ANG and NANG and the particulars of the calculation thereof.

5.6 The Royalty and Cess Statement for each Month shall be submitted to Government no later than ten (10) days after the end of such Month.

SECTION 6

VALUE OF PRODUCTION AND PRICING STATEMENT

6.1 The Contractor shall, for the purposes of Article 20 of the Contract, prepare a Statement providing calculations of the value of Crude Oil and Condensate produced and saved during each Month. This Statement shall contain the following information:

6.1.1 The quantities, prices and receipts realized therefor by the Contractor as a result of sales of Crude Oil and Condensate to third parties (with any sales to Government being separately identified) made during the Month in question.

6.1.2 The quantities, prices and receipts realized therefor by the Contractor as a result of sales of Crude Oil and Condensate made during the Month in question, other than to third parties.

6.1.3 The quantities of Crude Oil and Condensate appropriated by the Contractor to refining or other processing without otherwise being disposed of in the form of Crude Oil or Condensate.

6.1.4 The value of stocks of Crude Oil and Condensate on the first day of the Month in question.

6.1.5 The value of stocks of Crude Oil and Condensate on the last day of the Month in question.

6.1.6 The percentage volume of total sales of Crude Oil and Condensate made by the Contractor during the Month that are Arms Length Sales to third parties.

6.1.7 Information available to the Contractor, insofar as required for the purposes of Article 20 of the Contract, concerning the prices of competitive crude oils produced by the main petroleum producing and exporting countries including contract prices, discounts and premia, and prices obtained on the spot markets.

6.2 The Contractor shall, for the purpose of Article 22 of the Contract, prepare a Statement providing calculations of the value of Associated Natural Gas and Non Associated Natural Gas produced and sold during each Month. This Statement shall contain all information of the type specified in Section 6.1 for Crude Oil as is applicable to Gas and such other relevant information as may be required by Government.

6.3 The Statements required pursuant to Sections 6.1 and 6.2 shall include a detailed breakdown of the

calculation of the prices of Crude Oil, Condensate, Associated Natural Gas and Non Associated Natural Gas pursuant to the provisions of Articles 20 and 22.

6.4 The Value of Production and Pricing Statement for each Month shall be submitted to Government not later than twenty one (21) days after the end of such Month.

SECTION 7

STATEMENT OF COSTS, EXPENDITURES AND RECEIPTS

7.1 The Contractor shall prepare with respect to each Quarter a Statement of Costs, Expenditures and Receipts under the Contract. The Statement shall distinguish between Exploration Costs, Development Costs and Production Costs and shall separately identify all significant items of costs and expenditure as itemised in Section 3 of this Accounting Procedure within these categories. The Statement of receipts shall distinguish between income from the sale of Petroleum and incidental income of the sort itemised in Section 3.4 of this Accounting Procedure. If the Government is not satisfied with the degree of disaggregation within the categories, it shall be entitled to request a more detailed breakdown. The Statement shall show the following:

7.1.1 Actual costs, expenditures and receipts for the Quarter in question.

7.1.2 Cumulative costs, expenditures and receipts for the Year in question.

7.1.3 Latest forecast of cumulative costs, expenditures and receipts at the Year end.

7.1.4 Variations between budget forecast and latest forecast and explanations thereof.

7.2 The Statement of Costs, Expenditures and Receipts of each Quarter shall be submitted to Government no later than twenty one (21) days after the end of such Quarter.

SECTION 8

COST RECOVERY STATEMENT

8.1 The Contractor shall prepare with respect to each Calendar Quarter a Cost Recovery Statement containing the following information:

8.1.1 Unrecovered Contract Costs carried forward from the previous Quarter, if any.

8.1.2 Contract Costs for the Quarter in question.

8.1.3 Total Contract Costs for the Quarter in question (Section 8.1.1 plus Section 8.1.2).

8.1.4 Quantity and value of Cost Oil taken and disposed of by the Contractor for the Quarter in question.

8.1.5 Contract Costs recovered during the Quarter in question.

8.1.6 Total cumulative amount of Contract Costs recovered up to the end of the Quarter in question.

8.1.7 Amount of Contract Costs to be carried forward into the next Quarter.

8.2 Where necessary, the information to be provided under Section 8.1 shall be identified separately Field by Field and also separately for Crude Oil, Condensate, Associated Natural Gas and Non Associated Natural Gas.

8.3 The cost recovery information required pursuant to subsection 8.1 above shall be presented in sufficient detail so as to enable Government to identify how the cost of assets are being recovered for the purposes of Article 28 of the Contract.

8.4 The Cost Recovery Statement for each Quarter shall be submitted to Government not later than twenty one (21) days after the end of such Quarter.

SECTION 9

PRODUCTION SHARING STATEMENT

9.1 The Contractor shall prepare with respect to each Quarter a Production Sharing Statement containing the following information:

9.1.1 The calculation of the applicable net cash flows as defined in Appendix D for the Quarter in question.

9.1.2 The value of the Post Tax Rate of Return or the Investment Multiple applicable in the Quarter in question.

9.1.3 Based on Section 9.1.2 and Article 16, the appropriate percentages of Profit Petroleum for the Government and Contractor in the Quarter in question.

9.1.4 The total amount of Profit Petroleum to be shared between the Government and Contractor in the Quarter in question.

9.1.5 Based on Sections 9.1.3 and 9.1.4, the amount of Profit Petroleum due to the Government and Contractor as well as to each constituent of the Contractor in the Quarter in question.

9.1.6 The actual amounts of Petroleum taken by the Government and Contractor as well as by each constituent of the Contractor during the Quarter in question to satisfy their entitlements pursuant to Section 9.1.5.

9.1.7 Adjustments to be made, if any, in future Quarters in the respective amounts of Profit Petroleum due to the Government and Contractor as well as to each constituent of the Contractor on account of any differences between the amounts specified in Sections 9.1.5 and 9.1.6, as well as any cumulative adjustments outstanding from previous Quarters.

9.2 Where necessary, the information to be provided under Section 9.1 shall be identified separately for each Field and also separately for Crude Oil and Condensate as distinct from Natural Gas.

9.3 The Production Sharing Statement shall be submitted to Government not later than twenty one (21) days after the end of such Quarter.

SECTION 10

END OF YEAR STATEMENT

10.1 The Contractor shall prepare a definitive End of Year Statement. The Statement shall contain aggregated information in the same format as required in the Production Statement, Royalty and Cess Statement, Value of Production and Pricing Statement, Statement of Costs, Expenditures and Receipts, Cost Recovery Statement and Production Sharing Statement, but shall be based on actual quantities of Petroleum produced, income received and costs and expenditures incurred. Based upon this Statement, any adjustments that are necessary shall be made to the transactions concerned under the Contract.

10.2 The End of Year Statement for each Year shall be submitted to Government within sixty (60) days of the end of such Year.

SECTION 11

BUDGET STATEMENT

11.1 The Contractor shall prepare a Budget Statement for each Year. This Statement shall distinguish between budgeted Exploration Costs, Development Costs and Production Costs and shall show the following:

11.1.1 Forecast costs, expenditures and receipts for the Year in question.

11.1.2 A schedule showing the most important individual items of total costs, expenditures and receipts for the said Year.

11.2 The Budget Statement shall be submitted to Government with respect to each Year not less than ninety (90) days before the start of the said Year provided that in the case of the Year in which the Effective Date falls, the Budget Statement shall be submitted within ninety (90) days of the Effective Date.

APPENDIX D

(ARTICLE 16.4)

CALCULATION OF THE POST TAX RATE OF RETURN FOR PRODUCTION SHARING PURPOSES

1. In accordance with the provisions of Article 16, the share of the Government and the Contractor respectively of Profit Petroleum from any Field in any Year shall be determined by the Post Tax Rate of Return (hereinafter referred to as PTRR) earned by the Companies from the Contract Area at the end of the preceding Year. These measures of profitability shall be calculated on the basis of the appropriate net cash flows as specified in this Appendix D.

2. In order to assess the PTRR earned by the Company(ies) in the Contract Area over any period up to the end of any particular Year, the following net cash flow of the Company(ies) arising from the Contract Area for each Year separately will first be calculated as follows:

(i) Cost Petroleum entitlement of the Companies as provided in Article 15;
plus

(ii) Profit Petroleum entitlement of the Companies as provided in Article 16;
plus

(iii) the Companies' share of all incidental income (of the type specified in Section 3.4 of the Accounting Procedure) arising from Petroleum Operations;
less

(iv) the Companies' share of those Production Costs incurred on or in the Contract Area;
less

(v) the Companies' share of those Exploration Costs (if any) incurred in the Contract Area;
less

(vi) the Companies' share of Development Costs in the Contract Area, which, for the purposes of this paragraph 2(vi), shall be all of the Development Costs without regard to the provisions of Article 15.5(b);
less

(vii) the notional income tax, determined in accordance with paragraph 7 of this Appendix, payable by the Companies on profits and gains from the Contract Area.

provided, however, that any costs or expenditures which are not allowable as provided in Section 3.2 of the Accounting Procedure shall be excluded from Contract Costs and disregarded in the calculation of the annual net cash flow.

3. In order to determine what PTRR has been earned by the Companies from the Contract Area, the aggregate value for each Year of the net cash flow determined as specified in paragraph 2 above and earned during the Year shall be calculated and the amount obtained shall be called The Net Cash Balance. To this amount, at the end of each Year, shall be added The Opening Balance (which shall be deemed to be zero in the case of the first year for which the calculations are being made). The aggregation of The Opening Balance and The Net Cash Balance in any Year shall be called The Closing Balance for the Year in question.

4. The Closing Balance for the Year shall then be compounded forward at the rates of return specified in Article 16 of this Contract and the results shall form The Opening Balance for the subsequent Year's calculations. A separate set of calculations (of Closing and Opening Balances) will thus be performed for each of the rates of return specified in Article 16.

5. When the Opening Balance for a Year at a particular PTRR is negative and the Closing Balance for the Year becomes positive at that PTRR, the Companies shall be regarded as having achieved that PTRR during the Year. The Profit Petroleum shares shall then be determined pursuant to Article 16, depending on which PTRR has been achieved, and that split shall apply from the start of the subsequent Year and shall remain in force until a higher PTRR is earned which, in accordance with Article 16, triggers a different Profit Share.

6. If, in any later Year, costs are incurred by the Contractor, after the approval of the Management Committee, in connection with secondary recovery or enhanced oil recovery operations in respect of an Oil Field or a Gas Field, and such costs create a negative Net Cash Balance for the Year, then, if the Closing Balance for the previous Year was positive, the Opening Balance for that Year shall be deemed to be zero and the calculations itemised at paragraphs 3, 4 and 5 above shall commence again.

7. General

In determining the amount of notional income tax to be deducted in the applicable cash flows specified in paragraph 2 of this Appendix, a notional income tax liability in respect of the Contract Area shall be determined for each Company comprising the Contractor, as if the conduct of Petroleum Operations by the Company in the Contract Area constituted the sole business of the Company and as if the provisions of the Income-Tax Act, 1961, with respect to the computation of income tax were accordingly applicable separately to the Contract Area, disregarding any income, allowances, deductions, losses or set-off of losses from any other contract area or business of the Company.

APPENDIX E

FORM OF PARENT GUARANTEE

(To Be Furnished Pursuant to Article 30 of the Contract)

WHEREAS _____ a company duly organised and existing under the laws of _____ having its registered office at _____ (hereinafter referred to as 'the Guarantor' which expression shall include its successors and assigns) is the Affiliate of XYZ Company and

WHEREAS XYZ Company is signatory to a Production Sharing Contract dated the day of ,1994 in respect of an offshore area identified as the Ravva Oil and Gas Field (hereinafter referred to as 'the Contract') made between the Government of India (hereinafter referred to as 'the Government'), Oil and Natural Gas Corporation Ltd (hereinafter referred to as ' ONGC' which expression shall include its successors and assigns) and XYZ Company (hereinafter referred to as XYZ which expression shall include its successors and permitted assigns); and

WHEREAS the Guarantor wishes to guarantee the performance of XYZ Company or its Affiliate Assignee under the Contract as required by the terms of the Contract;

NOW, THEREFORE this Deed hereby provides as follows:

1. The Guarantor hereby unconditionally and irrevocably guarantees to the Government and ONGC respectively that it will make available, or cause to be made available, to XYZ Company or any Affiliate of XYZ Company to which any part or all of XYZ Company's rights or interest under the Contract may subsequently be assigned ('Affiliate Assignee'), financial, technical and other resources required to ensure that XYZ Company or any Affiliate Assignee can carry out its obligations to the Government and ONGC respectively as set forth in the Contract and any obligations flowing therefrom.

2. The Guarantor further unconditionally and irrevocably guarantees to the Government and ONGC respectively the due and punctual compliance by XYZ Company or any Affiliate Assignee, of any obligations of XYZ Company or any Affiliate Assignee under the Contract to the Government and ONGC respectively.

3. The Guarantor hereby undertakes to the Government and ONGC respectively that if XYZ Company, or any Affiliate Assignee, shall, in any material respect, fail to perform its obligations under the Contract to

the Government and ONGC respectively or commit any breach of such obligations, then the Guarantor shall fulfil or cause to be fulfilled the said respective obligations in place of XYZ Company or any Affiliate Assignee, and will indemnify the Government and ONGC as the case may be against all losses, damages, costs, expenses or otherwise which may result directly from such failure to perform or breach on the part of XYZ Company.

4. This guarantee shall take effect from the Effective Date and shall remain in full force and effect until no sum remains payable by XYZ Company, or its Affiliate Assignee, under the Contract to the Government or ONGC respectively or as a result of any decision or award made by any expert or arbitral tribunal thereunder.

5. This guarantee shall not be affected by any change in the Articles of Association and bye-laws of XYZ Company or the Guarantor.

6. The liabilities of the Guarantor shall not be discharged or affected by (a) any time indulgence, waiver or consent given to XYZ Company under or in respect of this Guarantee; (b) any amendment to the Contract or to any security or other guarantee or indemnity to which XYZ Company has agreed; (c) the enforcement or waiver of any terms of the Contract or of any security, other guarantee or indemnity; or (d) the dissolution, amalgamation, reconstruction or reorganisation of XYZ Company.

7. This guarantee shall be governed by and construed in accordance with the laws of India.

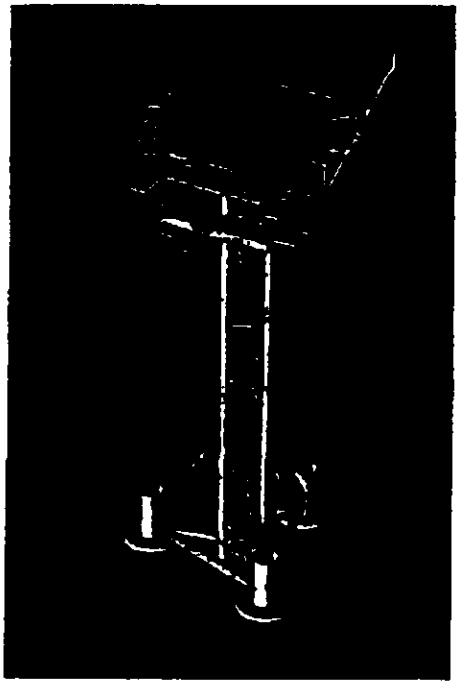
IN WITNESS WHEREOF the Guarantor, through its duly authorised representatives, has caused its seal to be duly affixed hereto and this guarantee to be duly executed the day of 1994.

THE COMMON SEAL of [Parent Company] was hereunto duly affixed in accordance with its Articles of Association in the presence of :

Secretary

Director

Proposed Development Plan for the Ravva Field



Submitted by

Command Petroleum Holdings N.L.

for and on behalf of the

Videocon-Command Joint Venture

July 1993

Command Petroleum Holdings NL

A.C.N. 001 695 398

PROPOSED DEVELOPMENT PLAN

for the

RAVVA FIELD

(including AUGUST 1993 ADDENDUM

and OCTOBER 1993 ADDENDUM)

by

COMMAND PETROLEUM HOLDINGS N.L.

for and on behalf of the

VIDEOCON-COMMAND JOINT VENTURE

Report No: 1993/024

October 1993

PREFACE

This Development Plan will greatly extend the development of the Ravva Field. It is based upon Command Petroleum Holdings NL's ("Command's") knowledge of the development of Australian oilfields with similar reservoir characteristics, water depths, distance to shore and generally comparable marine and climatic environments. Command believes that the blend of innovative and orthodox technology used to develop these fields offshore Australia can be applied successfully to the Ravva Field to maximise recoverable reserves and therefore provide optimum financial returns to all relevant parties, including the Government of India. The Development Plan uniquely combines an aggressive approach, aimed at achieving maximum production rates as quickly as possible, with a highly developed awareness of the importance of cost efficiencies and an overriding requirement that all operations be carried out in a safe and environmentally friendly manner.

Two main assumptions have been made. Firstly, it is assumed that the technical conclusions derived from the review of the field data made available as part of the Bid Application preparation process will not be changed significantly after all the field information has been examined and analysed. Secondly, it has been assumed that the processes of tendering for and procuring materials and services will adhere to normally accepted international industry practices.

This Development Plan comprises the initial plan, prepared and submitted to the Government of India in July 1993, and two Addenda. Addendum 1, submitted in August 1993, outlines a number of detail changes to the plan arising from the acquisition from ONGC of additional relevant data. Addendum 1 also incorporates a modified production profile, wherein the field is limited to a plateau rate of 40,000 BOPD to address third party concerns that the initial proposal of 50,000 BOPD might be difficult to achieve in practice. Addendum 2, a letter submitted in October 1993 in response to specific ONGC and Ministry of Petroleum queries, provides further clarification of certain aspects of the bid, including the firm exploration/appraisal commitment, limitation of capital expenditure recovery, and the implications of a reduction in plateau production rate from 40,000 to 35,000 BOPD. On the last of these items, the Bidding Group agreed to restrict the field to a plateau production rate of 35,000 BOPD with the expectation that this restriction would be reviewed at an appropriate time in the future.

It is important to note that the initial Development Plan assumed licence award at end September 1993 and that both Addenda assumed licence award at end October 1993. Project timing will be dependent on the actual award date, the need to carry out offshore installation work within a December to March weather window being a critical consideration in the overall plan.

PROPOSED DEVELOPMENT PLAN FOR THE RAVVA FIELD

PREFACE

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Addendum 1

August 1993

Addendum 2

October 1993

SUMMARY

Command, as Operator for and on behalf of the Videocon-Command Joint Venture and, subject to contract award ONGC, will greatly extend the development of the Ravva Field in an innovative and efficient manner.

The Development Plan will :-

- maximise recovery of oil from Blocks R10 and R17 by waterflooding and by optimising well numbers and locations;
- achieve maximum oil production rate within 21 months of contract award;
- produce the expected 100 million barrel oil reserve over a 16 year period;
- commence early appraisal and tie-in of reserves outside the presently defined Blocks R10 and R17;
- minimise capital and operating costs, thereby maximising the return to all parties, including the Government of India;
- adopt and implement techniques and procedures which will ensure a safe development and will minimise the impact of the development on the environment;
- use local Indian personnel, expertise and materials wherever practical.

The Development Plan will achieve the following production schedule :-

- up to 12,000 barrels of oil per day within 8 months;
- 30,000 barrels of oil per day within 14 months;
- plateau rate of 50,000 barrels of oil per day after 21 months; and
- two-year plateau oil production before onset of a 12 year decline.

The Development Plan is phased as follows :-

Phase 1

- install tanker loading facilities;
- pre-drill six template wells;
- install and tie-in one Block R10 platform;
- install in-field produced fluids pipeline;
- install onshore processing capacity of 30,000 barrels per day; and
- completion - 14 months from licence award.

Phase 2

- install and tie-in two Block R17 and one Block R10 platforms;
- drill and tie-in a total of 12 platform wells;
- install produced fluids, water injection and gas lift pipelines;
- upgrade onshore processing capacity to 60,000 barrels per day;
- build 500,000 barrels onshore oil storage, and
- completion - 21 months from licence award.

Phase 3

- install gas lift facilities onshore, in 1997 or later (as needed).

The total capital cost of the development is estimated to be US$170 million. This figure includes an appropriate contingency amount but excludes import duty which may be payable on some component parts of the cost. Operating costs are estimated to be US$12 million per year.

The Development Plan is based on production of oil reserves in Blocks R10 and R17 only. There is potential for additional commercial reserves to exist elsewhere in the Ravva Field licence area. This potential will be appraised in a timely manner and, if proven, these additional reserves will be developed as quickly as possible, using the infrastructure detailed in this report.

Associated gas production is expected to be as high as 25 million cubic feet per day during the 21 month plateau period of oil production. While an absence of commercial data has precluded the design or costing of facilities for the processing and transport of this gas, it is Command's intention that it be sold into what is understood to be an existing market. Therefore, Command would immediately move to investigate the market potential with a view to selling not only the associated gas, but also the non-associated gas known to exist in the Ravva Field licence area. The ability to sell excess produced gas will further, and very significantly, enhance the return to all parties.

1 INTRODUCTION

The Ravva Field lies 10 to 15 km offshore India in the Bay of Bengal (Figure 1) in 10 to 15m of water and was discovered by the Oil and Natural Gas Commission of India ("ONGC") in 1987. Twenty-eight wells have been drilled in and around the Ravva Field, 19 of which intersected significant hydrocarbons. The two main pools of oil delineated to date, designated Blocks R10 and R17, contain approximately 300 million barrels of recoverable oil and have been the subject of development studies since 1987. This development work by ONGC culminated in early 1993 with the installation of two wellhead structures, one at each of wells R-10 and R-17, and two flowlines to shore. Production from the field commenced in March 1993.

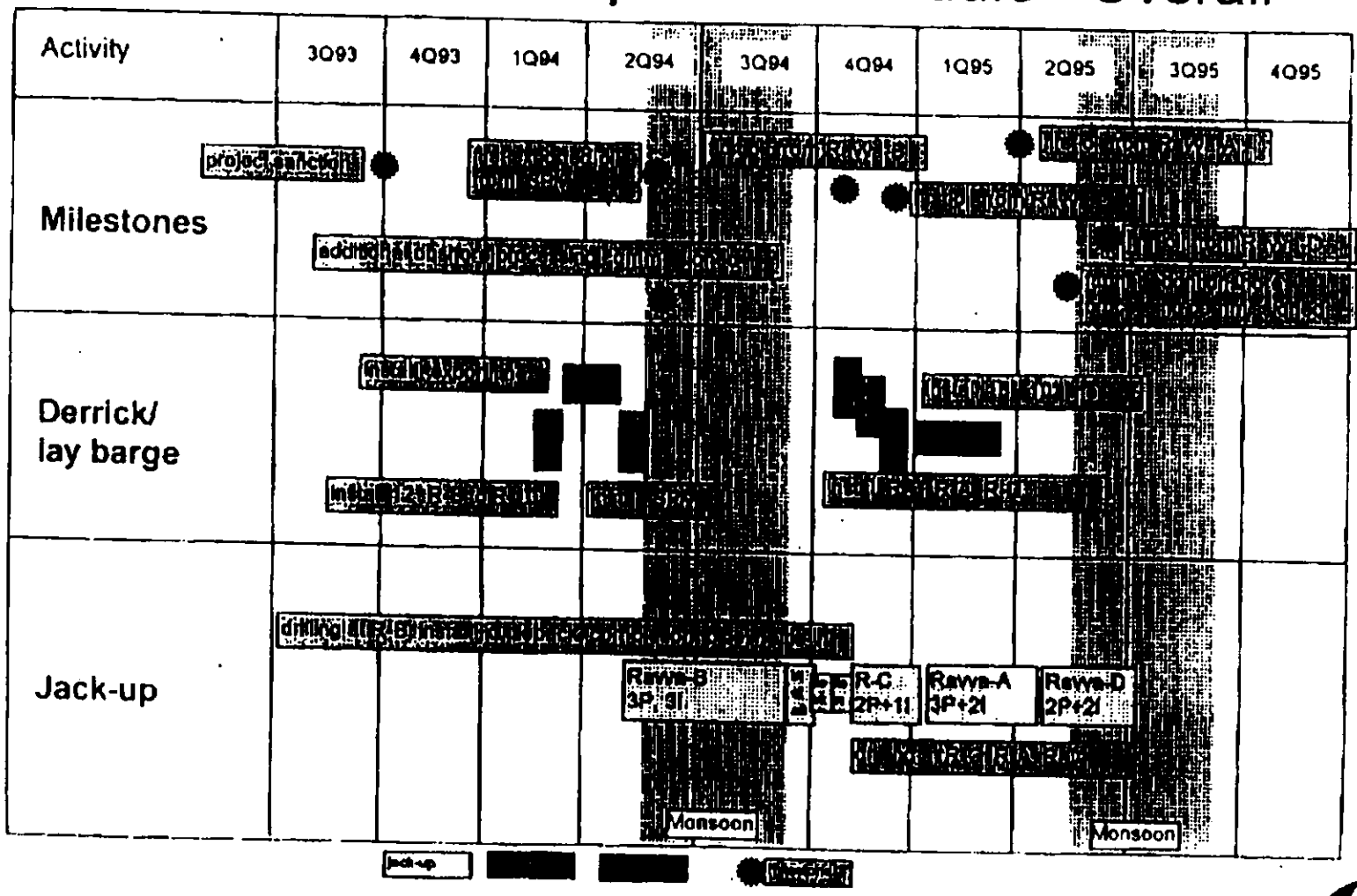
On 31 March 1993 Videocon International Ltd ("Videocon") and Command submitted to the Government of India an Application to develop the Ravva Field. The Application was in response to an offer made in 1992 by the Government to Indian and foreign companies to participate with ONGC in a joint venture, the objective of which was to develop the Ravva Field in a manner which optimised the return from the resource to all parties. This report details the Development Plan outlined in the Application.

The Development Plan detailed herein, has been prepared by Command using both its corporate and its personnel's experience gained from developing oilfields in shallow water off the northwest coast of Australia, an area subjected to cyclonic storms. Worley Engineering (Australia) Pty Ltd ("Worley"), a major engineering consultant in the oil and gas sector in Australia and Southeast Asia, has assisted in the preparation of the plan by conducting preliminary engineering and design of all the facilities contemplated for installation during the development. Worley's work has permitted the sizing and costing of all the components of the proposed development.

The combination of Command's and Worley's experience and engineering knowledge has resulted in the preparation of a plan which has a high level of credibility. Included in Appendix 3 are curriculum vitae of the key personnel responsible for compiling the plan.

This plan is submitted by Command on behalf of the Videocon-Command Joint Venture. If accepted by the Government of India a joint venture between Videocon, Command and ONGC will be entered into with Command nominated as Operator.

Ravva Field Development Schedule - Overall



2 GEOLOGY, RESERVES AND PRODUCTION

2.1 Regional Setting

The Krishna-Godavari Basin contains sediments of Permian to Holocene age (Figure 2), deposited during the evolution from a rift basin to a passive margin setting. Rifting occurred in the Jurassic-Early Cretaceous and a series of northeast-southwesterly trending horsts and grabens developed (Figure 3). By the end of the Cretaceous, the grabens had been nearly filled and a strong regional dip to the southeast developed due to post-rift thermal subsidence.

During the Tertiary and particularly during the Miocene-Holocene, the paleo Krishna and Godavari river systems deposited enormous amounts of clastics in a southeasterly prograding deltaic system, mainly in the East Godavari Sub-basin (Figure 3). During the Paleocene and Eocene, a regressive sequence of moderately well sorted sandstone and shelfal limestones were deposited near the present coastline and deep water claystones accumulated seaward. At this time, growth fault related anticlines were formed in a narrow zone southeast of the Tanuku Horst, just west and southwest of the Ravva Field.

During the Miocene-Holocene, the depositional rate increased and the deltaic complexes prograded further to the southeast. Rapid loading over a predominantly claystone substratum led to the formation of series of progressively younger growth faults and associated anticlines, restricted to the southeast by the shale diapirs. The Ravva structure was formed by one such listric fault, soling out above the Cretaceous section, and was segmented by younger, and relatively minor growth faults.

2.2 Ravva Field

The Ravva structure is large, covering approximately 120 km²/30,000 acres and was formed by growth faulting and shale diapirism. The structure is discussed in Section 2.3.

Hydrocarbons are reservoired in Late Miocene and Pliocene sandstones (Figure 4) in several fault blocks. Many of the growth faults within the overall structure appear to seal and the high claystone content of the section also allows juxtaposition across faults of seals (claystones) and reservoir (sandstones).

The Early to Middle Miocene section (Figure 4) was deposited in middle to outer neritic or deeper water conditions. Sandstones are generally thin and shaly and the section is overpressured.

The main reservoir units generally lie between 1500 and 1800m. The sandstones were deposited in shallow marine, high energy conditions, during sea level lowstands and are interpreted to be largely barrier bar and distributary mouth bar deposits. Sand units are up to 75m thick, but are more generally 5-20m thick and appear to be quite laterally extensive. They are often composed of stacked 1-2m thick beds in a gross upward coarsening (shoaling) sequence. The higher energy sandstones are medium to coarse grained and highly porous and permeable. Lower energy lower shoreface sandstones are finer grained and contain a significant amount of clay laminations. The depositional model used in this Development Plan predicts that sand thickness increases and quality improves towards the crests of the fault blocks, which areas would have been subtle paleotopographic highs when compared to the areas above the hanging wall. Greater wave energy and subsequently better winnowing may have improved the reservoir quality in these areas. This model is suggested and supported by the reservoir pressure data in wells R-10 and R-12. The indication that the three main sand units are in the same pressure system implies that the sands are in communication. The paucity of interpreted faults within the fault block suggests that the sands must thicken and the intervening shales thin.

Several unconformities and large scale erosive channelling can be recognised on seismic data. Large scale scouring, probably caused by the major river systems during sea level drops, is present in the very shallow section. A major period of channelling occurred near the end of the Miocene, and the northwest-southeast oriented channels have cut across the structural grain, thus creating paleotopographical traps. Very few faults cut this basal Pliocene unconformity. An older, smaller scale erosive event has affected the preservation of sandstone in the Block R17 area and may have helped form the associated hydrocarbon trap.

The channel fill is largely clay prone and is therefore a good seal. Some thin sandstones, occasionally hydrocarbon bearing, have been encountered in the Pliocene section. The traps formed by the erosional channelling are similar to many of the large oilfields in the Gippsland Basin of southeastern Australia where Command has a substantial interest in an exploration permit displaying comparable features.

The rapid sedimentation rate has adversely affected the resolution of palaeontological dating within the section of interest. It is therefore difficult, at this stage, to confidently correlate sandstones between fault blocks. Nevertheless, the sandstones present between 1,600 and 1,800m in many of the fault blocks are probably of much the same age. The palaeontological work done to date will be carefully reviewed.

The section is normally pressured to approximately 2,000m. A transition zone about 250m thick overlies a highly overpressured zone (Figure 5). The major hydrocarbon accumulations are normally pressured, but many abnormally pressured hydrocarbon bearing sands have also been intersected.

2.3 Structure

2.3.1 Data Set

The seismic data set over the Ravva licence area consists of 613 km of 2D data, acquired between 1978 and 1990 (Figure 6), and a 3,600 line kilometre 3D survey, which was acquired in 1990 (Figure 7). The 3D survey was recorded in the strike (northeast/southwest) direction, with a line spacing of 50m and a group interval and shotpoint interval of 25m.

Data quality of the 2D seismic varies from very poor to good, with the 1982/83 AT Series of lines being of generally better quality.

Data quality of the 3D seismic varies from very poor to good, with the quality being good in the area of wells R-17 and R-27, poor to fair in the area of wells R-9, R-10 and R-12, and very poor to the northeast and along the northern edge of the survey, i.e. wells R-5 and R-13. In 1990 Geopic reprocessed 9 strike and 34 dip lines using DMO, post DMO velocity analysis and migration. These lines were not available to determine quality.

All 2D and 3D seismic data will be reprocessed as soon as possible after the award of the contract. This will allow the development and appraisal drilling locations to be based on the interpreted data set. During reprocessing, emphasis will be placed on dip filtering, deconvolution and migration.

2.3.2 Interpretation

The Ravva structure developed by rotation into a major listric growth fault which soles out on the southeasterly dipping top Cretaceous surface (Figure 8).

The overall structure is illustrated in Figure 9, which is a two way time structure map on an horizon near the top of the main reservoir sand package.

Additional down to the basin growth faults developed basinward of the main fault during Miocene sedimentation. Several of these faults are significant and have effectively divided the structure into a series of major fault blocks

A period of major erosion occurred in the Late Miocene to Early Pliocene, due in part to a fall in sea level. The amount of erosion increases to the southeast, where uplift due to shale diapirism occurred. Large scale channels were cut into the Miocene sediments (Figure 10) and the amount of erosion has determined the present day extent of the main reservoir unit. Erosion seems to have occurred along fault planes in many cases.

The bulk of the oil resource defined to date lies in two separate fault blocks, informally named Blocks R10 and R17. The structure within these fault blocks is illustrated on Figures 11 and 12. Confidence in the structural interpretation of these two blocks ranges from fair to good.

2.4 Oil and Gas In Place

Oil-in-place in Blocks R10 and R17 has been independently calculated using the available data. A range of oil-in-place values has been calculated, reflecting the uncertainties inherent in the basic reservoir and fluid data.

The 2P oil-in-place in Blocks R10 and R17 is 27.5 MMT/203.7 MMBBL. Details of oil-in-place in the individual Blocks at 1P, 2P and 3P confidence levels are given in Table 1.

Gas-in-place in Blocks R10 and R17 has been estimated at the 2P confidence level to be 3.4 x 10^9 m^3/120 BCF.

Petrophysical data were derived principally from electric logs, in-house log analysis confirming ONGC's analysis on key wells. It appears that no core analysis has been carried out, against which the electric logs could be calibrated to improve the interpretation. Structural data were based on ONGC's interpretation of the 3D seismic, modified to account for subsequent wells.

The sections below briefly discuss the approach to the volumetric calculation of oil-in-place.

2.4.1 Fluid Contacts

In Block R10, gas-caps have been encountered in wells R-35 and R-36. Well R-35 intersected a gas-oil contact within a thick sand body and the gas overlies the oil zone directly. The gas at the top of the section in well R-36 may be separated from the oil by a thin shale, but it has been assumed to be in contact with the oil. These wells are in separate culminations and a gas-cap is also assumed to exist in a third culmination which exists between wells R-35 and R-36. This gas-cap abuts the main south-bounding fault but does not intersect the cross-cutting northerly trending fault which has been assumed to be non-sealing. The three different gas-oil contacts are shown on Figure 11.

No oil-water contact has been encountered in Block R10, lowest proved oil being at -1715 mBMSL.

In Block R17, gas-oil contacts are interpreted from logs and RFT data at 1640 mBMSL in well R-17 and 1630 mBMSL in well R-27, these wells being located in separate culminations. There is a possibility that the gas in well R-27 may be separated from the oil, as there is a thin claystone beneath the gas, but this is considered unlikely.

A well-defined and common oil-water contact is interpreted from logs at -1684 mBMSL. The Block R17 fluid contacts are shown on Figure 12.

2.4.2 Net Pay Determination

Porosity determination from logs was reasonably reliable. Logs were used to calculate net pay, and in the absence of porosity-permeability data from cores, the separation between the MSFL and the deep resistivity tools, together with the SP and caliper logs, was used to define effective permeable sandstone, i.e. net sand. Non-net was found to correspond approximately to a porosity cut-off of 15%. By this criterion, most net sandstones are shaly, containing from 5 to more than 30% clay and averaging more than 20% clay.

Net oil pay and net gas pay maps for Blocks R10 and R17 are presented as Figures 18 to 21 inclusive.

2.4.3 Porosity

The relatively modest computed porosities of 21 to 23% seem inconsistent with the high quality of some of the sandstones, formation testing indicating typical permeabilities of several Darcys. It appears that clay laminations, not resolvable on the logs and thus averaged into the sandstone, are probably common. Computed average porosities may therefore be slightly lower than actual.

In Block R17, an average porosity in the pay zone of 22.5% was estimated from logs.

In Block R10, an average porosity in the pay zone of 21.0% was estimated from logs.

2.4.4 Oil Saturation

ONGC's log analysis computes water saturations in the net pay averaging 40 to 45%, with a minimum value of 20%. Some sandstones with a calculated water saturation of 70% have produced oil at commercial rates, for example the test of the interval 1,737-1,743 mKB at well R-12. In-house analysis of well R-17 oil pay using a "complex lithology" programme, which utilises a sophisticated Archie approach, gave results very similar to ONGC's.

The computed water saturations, however, are inconsistent with the porosity and permeability data, from which we would expect

significantly lower values. It is quite likely that dual water or similar models will need to be applied to better model oil saturation. No improvement will be possible until reliable core analysis data are available for log calibration.

An average hydrocarbon saturation of 75% has been assumed for all net pay zones.

2.4.5 Fluid Properties

Surface oil and gas samples were collected during testing of wells R-10, R-12 and R-27 and subsequently recombined for laboratory PVT analysis, see Table 2.

In Block R10, several production tests on wells R-10 and R-12 produced at a gas-oil ratio of around 70 vol/vol. Recombined samples were taken and PVT analyses carried out, results being given in Table 2. Those analyses indicate that saturation pressures are 600 to 900 psi below reservoir pressure. Free gas exists in communication with the oil in Block R10 and the oil should therefore be at saturation pressure. The validity of the PVT analyses is doubtful.

In Block R17, the producing gas-oil ratio at well R-17 was reported as 35 vol/vol, whereas at well R-27 the gas-oil ratio averaged around 75 vol/vol, very similar to wells R-10 and R-12. As all other evidence points to wells R-17 and R-27 being in a single oil pool, the true R-17 gas-oil ratio is likely to be the same as that of well R-27. PVT analysis of the recombined well R-27 samples is given in Table 2, which indicates a saturation pressure of 2230 psi, more than 300 psi below the reservoir pressure. Given the presence of gas-caps in Block R17 (refer Section 2.4.1), the oil should be at saturation pressure. Therefore, the sample analysis is not considered representative of the reservoir fluid.

Until reliable and consistent fluid samples are obtained, or an explanation for the anomalies found, it is appropriate to use estimated properties of the oil in the reservoir. An oil formation volume factor of 1.3 vol/vol has been assumed, reflecting a belief that there is more gas in solution than the analyses indicate and that the oil is saturated. Oil gravity is 35° API, equivalent to 7.4 barrels per tonne.

2.4.6 Net Oil and Gas Zone Rock Volumes

2.4.6.1 Block R10

Oil and gas are reservoired in three main sand bodies which, on the basis of pressure data, are in the same reservoir system.

The Block R10 oil accumulation is within a tilted fault block, bounded to the northwest and southeast by growth faults (Figure 11). The structural style is illustrated by geological cross sections across the block (Figures 13 and 14). The southeastern and probably the northern bounding faults are sealing faults and thus the structural relief may be more than the 160m indicated.

The main reservoir sands are good quality shallow marine barrier bar to distributary mouth bar deposits. They can be correlated between wells within and near to the block with moderate confidence. Net effective sand has been modelled as increasing towards the crest of the fault block. The sand distribution is illustrated on the two geological cross-sections (Figures 13 and 14), which also depict known and assumed fluid contacts.

The net oil pay has been calculated to the Low Proved Oil (LPO) level only, but even if no water is present in the block, the additional oil-in-place will not be significant. Net oil pay within Block R10 is estimated to range from 5 to 32m (Figure 18)

Planimetering of Figure 18 gives a net oil zone rock volume of 151×10^6 m^3.

Net gas pay in three separate culminations is shown in Figure 20. The combined net gas zone rock volume shown is 12.2×10^6 m^3.

confidence levels is 13.6 MMT/101.0 MMBBL, 15.9 MMT/118.0 MMBBL and 18.4 MMT/136.5 MMBBL respectively.

Gas-in-place is calculated deterministically, using the calculated net gas zone rock volume, mean estimates of porosity and gas saturation and a gas expansion factor of 150 vol/vol.

Free gas-in-place= 288 x 10^6 m^3 (10 BCF)

In addition, there is estimated to be approximately 80 vol/vol (450 SCF/STB) solution gas in the oil. This gives 1.504 x 10^6 m^3 (53 BCF) solution gas-in-place at the 2P confidence level, or 1.792 x 10^6 m^3 (63 BCF) total gas-in-place.

2.4.7.2 Block R17

Triangular distributions have been assigned to Block R17 parameters as follows :-

	Low	*Middle*	*High*
Volume (10^6 m^3)	73	105	131
Porosity, Ø	0.20	0.225	0.25
Oil Saturation, So	0.65	0.75	0.80
FVF (vol/vol)	1.20	1.30	1.33

Converting to barrels, the results are given in Table 1 and Figure 22B. The low and high values for oil zone rock volume are 25% below and above the mean to allow for structural and stratigraphic uncertainties, including the size of the gas caps and the possible easterly extension of the pool. Block R17 oil-in-place at the 1P, 2P and 3P confidence levels is 9.8 MMT/72.6 MMBBL, 11.5 MMT/84.9 MMBBL and 13.7 MMT/101.1 MMBBL respectively.

Gas-in-place is calculated deterministically, using the calculated net gas zone rock volume, mean estimates of porosity and gas saturation and a gas expansion factor of 150 vol/vol.

Free gas-in-place= 506 x 10^6 m^3 (18 BCF)

In addition, there is estimated to be approximately 80 vol/vol (450 SCF/STB) solution gas in the oil. This gives 1.082 x 10^6 m^3 (38 BCF) solution gas-in-place at the 2P confidence level, or 1.588 x 10^6 m^3 (56 BCF) total gas-in-place

2.5 Recoverable Reserves

Recoverable reserves in Blocks R10 and R17 have been estimated by Monte Carlo analysis, applying a range of recovery factors to the ranges of oil-in-place detailed in Section 2.4. Recovery factor was estimated to range from 41% to 59%, with a most likely value of 50%.

The 2P recoverable reserves in Blocks R10 and R17 is 13.6 MMT/101.0 MMBBL. Details of recoverable reserves in the individual Blocks at 1P, 2P and 3P confidence levels are given in Table 1.

2.5.1 Reservoir Drive Mechanism

2.5.1.1 Block R10

The Block R10 reservoir sands are limited in extent principally by nearby sealing faults (Figures 11, 13 and 14). No oil-water contact has been encountered and while some water may be present downdip in the lower sands, the energy contribution would be negligible.

Log analysis indicates that two small gas caps are present and a third is inferred (Figure 11), the combined gas-cap to oil zone volume ratio, m, being 0.08. The pressure support from an expanding gas-cap of this size would be small. Solution gas drive would become effective as reservoir pressure dropped and, in combination with the small contribution of the expanding gas-cap and dependent on operational considerations, could give a recovery factor of 20 to 25 percent.

Typically, trying to produce an oil zone under expanding gas-cap drive, especially when a large amount of solution gas is also breaking out and forming a mobile saturation, can lead

to production of oil at very high gas-oil ratios, in turn depleting the compressive energy in the gas phase in the reservoir. It is likely that with the high reservoir permeability and high structural dip, gas breaking out of solution would tend to percolate efficiently to the crest, leaving crestal wells to produce largely gas or be shut in. Production at high gas-oil ratios would deplete reservoir energy and leave downdip producers with insufficient reservoir pressure to flow naturally to surface. Operational problems in maintaining oil production from wells below the advancing gas-oil contact can necessitate frequent well workovers, which is particularly undesirable offshore.

With some uncertainty over the size of the gas-caps in Block R10, with the inherent operational problems in producing oil under gas-cap expansion and solution gas drive, and with the relatively low expected recovery factor, it will be preferable to implement a waterflood programme. Artificial waterflood, injecting water downdip and driving oil towards crestal producers, will provide the most efficient drive mechanism and will be implemented in the Block R10.

2.5.1.2 Block 17

The Block R17 reservoir sands are limited in extent by nearby sealing faults and by subcrop against the erosional unconformity (Figures 12 and 15 to 17 inclusive). The water zone volume below the oil-water contact observed at 1684 mBMSL and in communication with the oil zone is approximately 2 to 3 times the oil zone volume. The energy contribution of an aquifer of this size is negligible in terms of providing a drive mechanism for the oil pool.

Log analysis and RFT recoveries indicate that two small gas caps are present (Figure 12), the combined gas-cap to oil zone volume ratio, m, being 0.19. The pressure support from an expanding gas-cap of this size would be significant, but insufficient to maintain adequate reservoir pressure throughout field life. As reservoir pressure dropped, solution gas would also break out and provide added energy. Depending on how the free gas saturations moved through

the reservoir and how wells were located and controlled to minimise produced gas-oil ratio, a combination of expanding gas-cap and solution gas drive could give a recovery factor of 25 to 30 percent.

As in Block R10, and for similar reasons, artificial waterflood will be implemented in Block R17 as the main drive mechanism.

2.5.2 Recovery Factor

Recovery factor has been estimated empirically as a function of microscopic recovery factor and of areal and vertical sweep efficiencies. Given the lack of relative permeability data and of reliable saturation and fluid property data, it was considered that detailed reservoir simulation was not warranted at this stage to estimate recovery factor.

Blocks R10 and R17 both lend themselves to an efficient line drive waterflood pattern because of their shape and structuring. A pattern of initial production wells will be drilled, including both crestal and downdip locations. Reservoir management considerations will dictate when to convert downdip production wells to injection wells. Reservoir pressure will be allowed to drop below saturation pressure, allowing a small free gas saturation to develop before implementing a waterflood programme. Empirical evidence suggests that sweep efficiencies are improved slightly, in addition to the benefits of having to inject to a lower pressure system. Modelling and field experience will be employed to optimise the timing of the waterflood.

We assume, for the purposes of estimating sweep efficiency, that the oil viscosity in the reservoir is 0.7 cp. Viscosity data from several samples is given in Table 2 and 0.7 cp is considered to be a conservative value to apply generally. Though no relative permeability data is available, it is very likely that the mobility ratio, $(k_w/\mu_o)/(k_w/\mu_w)$, will be favourable, ie greater than unity, leading to a stable flood front.

Correlations indicate that for a line drive waterflood such as this, areal sweep efficiency could be up to 55% at water breakthrough and over 90% by the time the producing water cut reaches 80%. These figures will require verification by numerical simulation.

Vertical sweep efficiency should also be good, helped by the dipping beds (averaging around 7° dip) and by the generally coarsening upwards sands.

Maximum achievable microscopic recovery factor is dependent upon Initial oil saturation and residual oil saturation when swept.

Log analysis and very limited core analysis (on sidewall cores) indicate an average oil saturation in the near-wellbore invaded zone of about 15%. This approximates irreducible or residual oil saturation.

A range of recovery factors has been calculated by a Monte Carlo probability model, using the equation :-

R.F. = S(areal) x S(vertical) x (1-Swi-Sor)/(1-Swi)

where :-

R.F.	=	recovery factor, fraction
S(areal)	=	areal sweep efficiency, fraction
S(vertical)	=	vertical sweep efficiency, fraction
Swi	=	initial water saturation, fraction
Sor	=	residual oil saturation,fraction

Input parameters have been assigned triangular distributions with low, middle and high values as follows :-

	Low	*Middle*	*High*
S(areal)	.70	.80	.95
S(vertical)	.50	80	.95
Swi	.20	.25	.35
Sor	.12	.15	20

Table 1 and Figure 23 show the expected recovery factor to be 50%, with a 90% chance of exceeding 41% and a 10% chance of exceeding 59%.

2.5.3 Calculation by Monte Carlo Analysis

A range of recoverable reserves is calculated for each Block and for the field using a Monte Carlo probability model, using the equation :-

Recoverable Reserves = Oil-in-Place x Recovery Factor

Oil-in-place in each of Blocks R10 and R17 is as per the distributions shown in Figures 22A and 22B. Recovery factor is as per the distribution described above and shown in Figure 23. In the analysis, the same recovery factor is applied to each Block.

The results of the recoverable reserves calculation are shown in Figures 24A, 24B and 24C, for Blocks R10 and R17 and the combined Blocks respectively.

The combined recoverable reserves at the 1P, 2P and 3P confidence levels are 10.9 MMT/80.5 MMBBL, 13.6 MMT/101.0 MMBBL and 16.9 MMT/124.9 MMBBL respective.

2.6 Well Productivity and Production Profile

2.6.1 Well Tests

Cased hole production testing was carried out on most Ravva wells which had significant oil or gas shows. Data from tests on wells R-10, -12, -17 and -27 have been reviewed. Although incomplete and containing some anomalies, these data were adequate to confirm that the reservoir sands have very high permeabilities and that significant apparent damage was evident on most tests.

Problems with data and interpretation have introduced errors to test analyses. These errors are estimated to be generally less than 30% on permeability, though skin factor in some cases appears to be overestimated by a factor of 2 or more due to using data from a poorly-positioned gauge. Test data will be re-interpreted when a complete data set, including fluid properties, is available.

The principal analysis results from tests on the above mentioned four wells are shown in Table 3; some comments on the results are given below.

2.6.1.1 Well R-10

Three tests of three different sands were carried out on well R-10, as indicated in Table 3. All tests produced at similar gas-oil ratios and major decreases in PI, as observed at wells R-17 and R-27, were not evident.

The first and second tests both indicated a PI of about 30 BOPD/psi and a flow efficiency of about 25%.

No build-up data from the third test was available for review. The PI was calculated to be around 12 BOPD/psi and the partial penetration effects of perforating only 2m out of a total of 14m of net sand would have been significant.

Well R-10 is now on long-term production and providing useful fluid and reservoir information.

2.6.1.2 Well R-12

Two relevant tests were carried out on well R-12. The first test, over the perforated interval 1737-1743 mKB, was of two sands which appeared on logs to be of relatively poor quality, Vshale being around 50% and interpreted water saturation 70%. The test produced clean oil at over 2100 BOPD to a wellhead pressure of 700 psi, confirming the high producibility of what appear on logs to be "poorer quality" sands. The well PI actually appeared to increase slightly over this multirate test, being about 4 BOPD/psi. Interpretation of the final build-up data indicates an average permeability of about 0.5 Darcys. Though this is significantly lower than calculated permeabilities at other wells and in other sands at this well, it is still a high value and is significant in assessing sand quality from logs.

The second test, reported in Table 3, added perforations from 1697-1706 mKB to those of the first test. A PI of about 20 BOPD/psi is calculated, but this would be in excess of 30 BOPD/psi if downhole choke effects are taken out. No significant decrease in PI was observed over the multirate test.

2.6.1.3 Well R-17

The test described in Table 3 and an earlier test over just the lower two sets of perforations both flowed clean oil to surface through a range of choke sizes. Oil PI decreased throughout, from an initial value of 50 BOPD/psi to 20 BOPD/psi by the end of the test. It is believed this was due primarily to free gas breakout in the reservoir, rather than to increasing mechanical damage. No solids production was reported over a total of approximately 100 hours flowing.

The producing gas-oil ratio on both tests was reported as around 35 vol/vol, much lower than at well R-27 or other comparable wells. Well R-17 will come on stream in September 1993 and an accurate assessment of oil and gas properties should then be possible.

2.6.1.4 Well R-27

The single multirate test at well R-27 was very similar to the second test on well R-17, strengthening the argument that the well R-17 producing gas-oil ratio may have been incorrectly reported.

As at well R-17, well R-27 exhibited declining PI throughout the increasing rate multirate test, again believed to be due primarily to free gas breakout near the wellbore.

At well R-27, data from two gauges show the significant downhole choking effect of the test tools, this effect being incorporated in the calculation of skin factor. Two-thirds of the flowing pressure loss between the reservoir and the Schlumberger "MUST" gauge was caused by the test tools themselves. Using pressure data from this gauge resulted in an overstated skin damage and an understated PI (by approximately a factor of 3). The interpretation of reservoir permeability was not affected.

2.6.2 Development Well Productivity

Well test analyses indicate that average permeability in the net pay sands encountered at Ravva can be expected to be of the order of 2 Darcys or more. If a zero-damage completion can be achieved, this should result in a PI of at least 7 BOPD/psi per metre of pay. The average pay interval is in excess of 20m, but wells will probably not be completed throughout the pay section. Depending upon well location, sand distribution and the extent of the perforated interval, an initial PI of well over 100 BOPD/psi should be achievable in some wells. To be conservative, an average initial PI of 30 BOPD/psi has been assumed for future development wells.

Flow rate may be restricted by sand integrity. The sand is reported to be not well consolidated so it is possible that gravel packing could be required, though none of the wells in Blocks R10 and R17 has produced significant sand on test.

Sand production is a potentially serious problem which will be addressed in detail before finalising well designs. Core studies and detail data from well tests and long-term production will be required. Sand production often starts when aquifer or injected water arrives at a producing well, so even though there may be little or no sand production when a well is producing clean oil, it might be necessary to plan for future sand production. The natural PI of the wells is likely to be sufficiently high that a significant restriction to flow, such as a gravel pack, could be accommodated and still leave a highly productive well. At this stage gravel packing is not expected to be necessary.

Individual production well rates have been limited to 6,000 BOPD when producing clean oil, corresponding to a drawdown pressure of some 200 psi. At the onset of water production the total fluid rate is limited to 4,000 BFPD to further protect against the possibility of sand production.

2.6.3 Well Production Profile

Full field reservoir simulation has not been carried out on Ravva at this stage. Such simulation will be done when more basic data are available and will be used to optimise development.

Simulation studies of single-producer drainage areas have been carried out to assess likely field performance. Information on the likely timing of water injection, timing of water breakthrough and timing of gas lift requirements has been obtained in this way. These studies also indicated that oil recoveries in excess of 50% can reasonably be expected and that the high permeability of the reservoir allows efficient drainage by few wells.

A "typical" individual well production profile has been developed based on :-

- total fluid rate restricted to 6,000 BFPD before water breakthrough and 4,000 BFPD after water breakthrough;
- ultimate well oil reserves of 9 MMBBL;
- pressure maintenance by downdip water injection commences at six months;
- gas lift available as necessary; and
- completed in oil zone, i.e., not a gas-cap blowdown well

Table 4 and Figure 25 show the resulting production profile for this typical well.

While well numbers are yet to be optimised, preliminary analyses indicate that as few as ten crestal producers would be adequate to efficiently drain both the R17 and R10 Blocks. This is the number of new crestal producers assumed in this Development Plan. In addition to these new producers there are four existing wells available for production, wells R-17 and R-34 at the well R-17 tripod, and wells R-10 and R-35 at the well R-10 tetrapod. In addition, there are spare slots on each production platform, the ability to produce from downdip wells prior to turning them into water injection wells, and the ability to re-drill watered-out producers. Consequently, the typical production profile adopted in the plan is considered easily achievable if it is applied to only the ten new development producers

2.6.4 Field Production Profile

A field production profile has been developed by combining production from individual wells as they come on stream according to the Development Plan. As the sum of individual well productivities exceeds the maximum field rate, wells are constrained to produce within overall field constraints. For any well the potential oil rate and actual water cut are determined from the well's cumulative production by interpolation of the rate-cumulative or water cut-cumulative figures of Table 4.

Field production rate is constrained by prudent reservoir management consideration to 50,000 BOPD, equivalent to 18.25 MMBO per year or about 18% of EUR (estimated ultimate recovery). This rate of offtake is considered to be safely achievable, with no adverse effects on ultimate oil recovery. The good reservoir quality will permit efficient sweep at these rates.

The resulting oil and water production profiles are given in Table 5 and Figures 26 to 30 inclusive. Producing gas-oil ratio is assumed to remain fairly constant, gas-cap production being ignored in the forecast. The oil profile can be achieved with or without the early blowdown of the gas-caps. Blowdown of the gas caps will ideally occur at a time when the gas can be sold.

2.7 Water Injection

Water injection is required to maintain reservoir pressure in both Block R10 and Block R17, as described in Section 2.5.1..

Reservoir pressure will be allowed to drop by several hundred psi before beginning water injection, since this allows reduced injection pressure and is generally considered to improve sweep efficiency. Early production will be from downdip or centrally located wells to minimise the amount of gas produced, gas tendering to migrate to the structural crest as reservoir pressure drops.

Modelling indicates that some 5 to 10% of oil-in-place can be produced before water injection is required, corresponding to approximately six months at peak production rate of 50,000 BOPD. The Development Plan anticipates that water injection facilities will be installed in the second

quarter of 1995, when cumulative production will be less than 8 million barrels, or 4% of 2P oil-in-place.

The timing and volume of water injection will depend on fluid properties and the extent of natural pressure support which exists. Prudence dictates that the Development Plan should cater for the early installation of facilities.

The Development Plan assumes that water injection will attempt to maintain reservoir pressure, i.e., to match reservoir volume offtake, from the second quarter of 1995. At the peak oil production rate of 50,000 BOPD, the 50,000 BWPD water injection capacity is not quite sufficient to balance offtake. However, this should not have an adverse effect as the shortfall is small and not long-lived. Figure 31 illustrates both the "ideal" water injection profile, for full balancing of offtake, and the actual expected profile, which is limited to 60,000 BWPD.

2.8 Gas Lift

Because the main drive mechanism for the oil in Blocks R10 and R17 will be artificial waterflood, it is expected that all producers will ultimately water out. Reservoir pressure will be maintained several hundred psi below hydrostatic, so significant water cuts will adversely affect the ability of a well to flow to surface at high rates.

It is expected that some form of artificial lift will be required to maintain and maximise well production at high water cuts and thus maximise total oil recovery. Pumping wells is generally not the best way to solve the problem offshore, and as the Ravva Field will produce adequate gas, the Development Plan envisages gas lifting high water cut wells.

Gas lift is assumed to begin when a well's water cut exceeds 50%, the gas lift volume increasing progressively as the water cut increases. Vertical flow pressure loss modelling indicates that gas supplied at around 250 scf per barrel of produced water should be sufficient to lift the well fluids to surface at a reasonable rate. Under this assumption, the field lift gas requirement throughout field life is shown on Figure 31. First lift gas is required in 1998 and peak requirement is a little under 11 MMscfd.

Detail design of gas lift facilities will be carried out after the field comes on stream, a significant water production is not expected for several years. At this stage it appears that a gas compression facility of 10 to 12 MMscfd

may be adequate, but the final requirements will depend on stable reservoir pressure, fluid properties, tubing design and gas lift mandrel location.

It is not anticipated that gas lift will be required in downdip or flank wells, since they will not be needed to produce to extremely high water cuts. Oil not produced from these wells will ultimately be pushed up-dip to the crestal producers.

2.9 Potential Additional Reserves

Based on review of available data, it is clear that additional reserves exist in the Ravva Field area. Some of these reserves may become commercial if gas markets can be developed or when the Ravva Field infrastructure is in place.

2.9.1 Well R-13

This well intersected two oil bearing and three gas bearing sands. On poor quality seismic data, ONGC mapped sands 1, 2 & 3, 4, 5 in time and depth. Oil-in-place is estimated to be 0.3 MMT (2.2 MMBBL) and gas-in-place is estimated to be 250 x 10^6 m^3 (8.8 BCF).

2.9.2 Wells R-7 and R-9

Well R-7 intersected two gas bearing sands while well R-9 intersected three gas bearing sands. The wells are considered to be in the same gas pool. Seismic data quality is poor. ONGC has mapped sands 1 and 3 in time and depth. Gas-in-place is estimated to be 952 x 10^6 m^3 (33.6 BCF), most of which is contained in sand 3.

2.9.3 Wells R-2 and R-8

Well R-2 intersected two oil bearing and one gas bearing sands. Well R-8 intersected five oil bearing and one gas bearing sands. The wells are considered to be accessing the same oil and gas pools. Seismic data quality is very poor. ONGC has mapped R-2 pay (-1677m) and R-8 pay (-2249m) in time and depth. Oil-in-place is estimated to be 0.9 MMT (6.7 MMBBL) and gas-in-place is estimated to be 52 x 10^6 m^3 (1.8 BCF).

2.9.4 Between Wells R-8 and R-15

A possible structural closure has been identified between these two wells, with considerable potential oil-in-place.

2.9.5 Eastern Extension of Block R17

A possible extension of the main Block R17 oil reservoir across the fault to the southeast has been identified. Estimated oil-in-place is 6.9 MMT (51 MMBBL). This area has good potential.

2.9.6 Other Potential

The area between wells R-10 and R-5 is considered to have exploration potential.

Relatively small amounts of gas-in-place are indicated in the R-22 and R-23 fault blocks and additional potential may exist there.

In addition to the above potential, considerable exploration potential remains, particularly in sections updip of current well intersections underneath the unconformity surfaces. The R-22 well, for example, intersected sands beneath the gas accumulations immediately underneath the unconformity. These sands dip strongly to the northwest, and are updip of the well further to the southeast. One of these sands tested 20% oil and 80% water, indicating a transition zone. Oil is probably present updip.

2.10 Data Review and Acquisition Requirements

References are made throughout this report to the requirement for additional data. In some cases data have not been acquired, in other cases information has been acquired but has not been available outside of ONGC and, in other cases, the data available have been of doubtful reliability.

To improve the efficiency with which the Ravva Field will be developed it will be necessary to proceed with certain activities immediately upon award of the licence. The timely completion of these activities is critical to the ability to meet the Development Plan schedule presented on this report.

The principal data review and acquisition requirements are detailed below.

2.10.1 Structural Interpretation

To improve Block R10 and Block R17 volumetric calculations, to identify new prospective exploration areas and to allow optimal location of development wells, the 3D seismic data will be reprocessed and interpreted. This activity is anticipated to take six months to complete and it is important that all seismic data tapes are made available within two weeks of the contract award.

2.10.2 Reservoir Fluid Properties

No reliable and complete fluid analysis from either Block R10 or Block R17 was available. Samples will have to be collected from the test separators on each of the R-10 and R-17 monotowers. Multiple samples must be collected under professional supervision to ensure correct recombination in the laboratory. Laboratory analyses must be checked and validated against long-term production history.

Reliable reservoir fluid property data is essential for activities such as :-

- oil-in-place calculations;
- recovery factor calculations;
- reservoir simulation to optimise well locations;
- well completion design;
- pipeline design; and
- process facilities design.

2.10.3 Core Analysis

On contract award, the available core should be made available for sampling, the samples being sent to a commercial laboratory for comprehensive analysis.

Core analysis will :-

- permit some degree of log calibration;
- give a better understanding of the reservoir geology;
- yield relative permeability and end-point saturation data; and
- allow determination of the tendency of the sands to break down under production conditions (i.e., will indicate whether gravel-packing might be necessary).

It is possible that available core is inadequate and unable to provide the required information over the sands of interest. In this case, parts of the core analysis requirement will have to wait until core is acquired in the first development wells.

2.10.4 Gas Caps

The existence of the inferred middle gas-cap in Block R10 (Figure 11) should be tested by the first development well drilled.

The presence of the interpreted gas-cap in the R-17 culmination of Block R17 (Figure 12) should be tested early in the development programme.

3 Development Plan

3.1 Field Development Concept

The Ravva Field will be developed by greatly extending the facilities already in place (Figure 32). Existing platforms at wells R-10 and R-17 and associated pipelines and onshore plant and tankage will be supplemented by:

- four new, cost efficient, unmanned production platforms R-A, R-B, R-C and R-D;
- offshore tanker loading facilities;
- one additional free-flow pipeline to onshore plant;
- a 60,000 barrel per day onshore processing facility;
- a 500,000 barrel tank farm;
- gas lift and water injection facilities including pipelines from the plant to the field; and
- produced water separation and disposal system.

In preparing this Development Plan, emphasis has been placed on the following aspects :-

- rapid increase in production rates;
- low capital cost;
- minimum installation time;
- high reliability and production output;
- low cost and ease of operating; and
- safety.

The provision of water injection and gas lift facilities will maximise recovery and maintain higher production levels than would otherwise be possible.

Safety systems and environmental controls will be appropriate for the facilities in accordance with recognised world standards. Offshore, and onshore at the plant and tank farm, personnel protection will meet international standards.

Formation water will be separated onshore from the hydrocarbon streams and will be used primarily as the source of water for reinjection.

The operation will be supported by an on site office and an administrative office at the operations base in Madras. Maintenance will be carried out to the maximum possible extent at the plant, or in nearby infrastructure where this is necessary. Offshore maintenance requirements will be minimised by keeping offshore equipment levels to an absolute minimum, and by using well established, reliable electrical and mechanical components.

Provision will be made to access platforms by either boat or helicopter to ensure year-round operability.

A phased approach to design and construction of the new facilities provides the best opportunity for a rapid increase in oil production. The projected production profile curve is shown on Figures 26 and 27.

In the proposed development schedule, early production is accelerated by using shuttle tankers to carry export crude while the two additional storage tanks are being built to service larger tankers.

3.2 Design Criteria

3.2.1 Oceanographic & Meteorological Data

3.2.1.1 Meteorology

The general climatology for the region is tropical, monsoonal. Thunderstorms occur mainly during June through September/October and average 20 per year. The predominant directions of weather and waves are longshore i.e north-northeast to southwest for 77% of the time, with the primary monsoon coming from the southwest. The north-northeast monsoon is considered fair weather typically with

light, variable winds and slight seas. Construction can be planned in this north-northeast monsoon season.

The yearly weather pattern typically breaks into four seasons as follows.

November-January	north-northeast monsoon season (secondary rough season)
February-April	transition (primary calm season)
May-September	southwest monsoon season (primary rough season)
October	transition (secondary calm season)

The practical construction weather window is therefore mid September to mid May.

When possible, critical construction activities have been minimised in the November to January period.

3.2.1.2 Surface Air Temperature

The extremes of surface air temperature range from 14°C in December to 47°C in June. The normal range is from 19°C to 37°C.

3.2.1.3 Humidity

Humidity is generally moderate to high throughout the year, with the range being from 61% to 83%.

3.2.1.4 Rainfall

The annual average rainfall is 1200 mm. For monthly averages at Kakinada based on 30 years of records refer to Table 6.

The heaviest recorded rainfall in 24 hours at Kakinada is 500 mm.

3.2.1.5 Sea Surface Temperature and Salinity

Figures quoted as typical for the region are 24°C to 30.5°C surface temperature, and from 30,000 to 35,000 ppm salinity.

3.2.1.6 Wave Climate

During the north-northeast monsoon, wave heights exceed 2m for about 14% of the time. In the southwest monsoon, wave heights greater than 2m occur for about 40% of the time. The predominant directions during these two periods are north through west and south through west-southwest respectively. During transition periods wave heights are relatively low and directions variable.

The wave periods associated with the waves up to 2m height range between 4 and 11 seconds and for heights greater than 2m, 6.5 and 14 seconds. Statistical data suitable for fatigue analysis has not yet been obtained but will be acquired for design purposes.

Maximum wave heights in the water depths relevant to the Ravva Field are limited by water depth. Thus the 100 year return period design wave is a breaking wave for which stream function theory applies, and range from 10.6m in 10 metres water depth to 14.4m in 15 metre water depth.

3.2.1.7 Cyclonic Storms

The probability distribution of various severity storms per month is given in Table 7.

3.2.1.8 Environmental data

The water depth at each proposed platform location is.

Platforms R-A, R-B, R-C and R-D will be set in water depths of 11, 10, 15 and 12 metres respectively.

Environmental data is given in Table 8.

3.2.2 Foundation Conditions

The Ravva Field lies offshore from the Godavari River Delta in 10-15m water depth. The foundation materials are therefore sedimentary in origin. The surface layers will have been subjected to substantial reworking by cyclonic storm waves. The assumed strata vary from a very soft silty clay to a stiff clay at a depth of 100m. Assumed soil parameters are as follows :-

Effective unit weight of soil (assumed for soft clay): 16 kN/m^3
Soil parameter J: 0.5 (assumed from API recommendations)
Reference strain e_{50}* 0.07% (assumed)

3.2.2.1 Soil Data

Limited soil information has been provided, however a curve showing Su versus depth provided guidance in estimating some properties as shown in Table 9.

3.2.3 Offshore Facilities Design Criteria

The offshore facilities will be designed in accordance with current best offshore design practice and internationally recognised codes. The various structural components will be designed for the following conditions :-

3.2.3.1 Substructure

- in place - design storm
- ultimate capacity - reserve strength ratio
- loadout and lift conditions
- on bottom stability
- fatigue
- boat impact/missing member analysis

- corrosion

A design life of 20 years is proposed.

3.2.3.2 Topsides

- in place including 100 year wind
- in place with helicopter and/or wireline loads
- transportation and lift configurations
- fatigue

3.2.3.3 Pipelines

- operating pressure
- pipelay stresses
- in place stability under wave and current action
- assessment of scour potential and effect of spans
- corrosion protection

3.2.3.4 Single Point Mooring ("SPM")

- operating conditions including assessment of limiting conditions for tanker attachment
- mooring impact forces
- installation conditions

3.2.4 Process Design Criteria

Current best practice and internationally accepted codes such as the US American Petroleum Institute standards will be used for design of

all process mechanical electrical and instrumentation systems. Key design conditions for the various components are as follows.

3.2.4.1 On-platform piping including wellheads, headers, test separator

- full shut in wellhead pressures
- flowing conditions
- min and max water cut and gas lift conditions
- emergency shutdowns

3.2.4.2 Onshore Process Plant

- RVP of 12 psi
- emergency shutdowns (including surge)
- pigging and slug receiving pressures
- peak flowrates of water oil and gas for relevant sections of field life
- monsoon conditions for spill containment

3.2.4.3 Electrical

To recognised international standards (eg UL, IEEE) and Indian wiring regulations. To the extent possible, systems will use local power supply standards.

3.2.4.4 Instrumentation and Control

To recognised international standards such as issued by API and ISA (Instrument Society of America)

3.3 Platforms

3.3.1 Overview

The platforms will be minimum facility, unmanned monotowers as depicted in Figure 33. It is intended that they will be able to be installed by either a derrick barge or a jack-up rig, will be capable of supporting up to six wellheads, contain well testing facilities and be capable of access by both helicopter and boat. A study was conducted to determine the most suitable type of structure using the available environmental and soil design criteria. Two types of structure were investigated in detail, a monotower structure with a tripod base piled to the seabed and a standard four-leg jacket

On the basis of weight and its ability to be installed by jack-up drilling rig, the monotower is proposed.

3.3.2 Sub-structure

The sub-structure consists of a 1.5m diameter central caisson supporting the topsides with a braced tripod base with pile sleeves at the bottom. Three steel piles are assumed to be inserted through the sleeves to fix the structure to the sea bed.

The height of the sub-structure is dependent on the water depth at the location where it is to be installed (Figure 34).

3.3.2.1 Conductors

Four conductors, 26" in diameter, will be installed external to the central caisson and two inside the caisson.

The conductors will be driven 10m below the pile tips so that pile capacities are not affected by the drilling process.

3.3.2.2 Other Lines/Risers

Large diameter (16" and 12") risers will be supported external to the central caisson and smaller flow lines up to 10" will be supported inside the caisson.



3.3.2.3 Access to Platform

Usual access to the platform will be by helicopter. A boat landing with two access levels will also be provided for access during wireline operations.

3.3.2.4 Drilling Access

The conductors have been located such that they are within the drilling envelope of a commonly available jackup rig.

3.3.3 Topsides Facilities

The topsides structure will consist of a 9m x 9m utilities/wellhead deck with a helideck roof structure. The "cellar" deck will be 20m above mean sea level, and total topside weight will be approximately 120 tonnes including helideck.

The helideck will be mounted concentrically with a hatch above each well location for development drilling, workovers and wireline access.

Facilities to be provided (Figure 35) will include manifolding for up to six wellheads; production test, gas lift and water injection headers, test separator, drain vessel, transfer pump, vent scrubber and scraper launcher. Also included will be emergency shut down panel, hydraulic panel, continuous down-hole corrosion package, fire and gas panel, gas conditioning package for power gas hoist etc.

The test separator and production and test heads (Figure 36) have been assumed to be designed for a well shut-in pressure of 2280 psig.

Power gas will be produced from the well stream and will be used to drive all small pumps and control valves. Electric power for the transfer pump and hoist will be provided from a workboat. Power for navigation lights, communications equipment, etc will be provided by solar cells charging a bank of 24 V/dc batteries.

3.3.4 Structural Design Analysis

3.3.4.1 100 Year Storm In-Place

The sub-structure was analysed for the 100 year return period storm. The analysis was used to obtain a first pass design of the member sizes, the pile size and required penetration. In the analysis, all members and piles were assumed to have a steel grade of 350 MPa. No joint analysis was performed as small changes in can sizes will not significantly affect the total sub-structure weight and cost estimates.

Waves in three critical directions were applied on the structure to impose lateral loading.

The wind on the topsides was simulated by applying a horizontal wind force in a direction corresponding to the waves. The wind force was estimated by assuming a 10m x 7m blocked off area and API's recommended wind force velocity relationships.

3.3.4.2 Foundation Analysis

The foundation design was carried out by carrying out a soil-pile interaction analysis. Due to a lack of geotechnical information, API's recommended soft clay parameters were used as a conservative approach. From the analysis it was determined that 1676 mm/66" plugged piles driven to 100m were required for structural stability.

3.3.4.3 Further Study Requirements

A detailed study of the structures using more recent environmental data for specific water depths.

A detailed pile-soil interaction study with proper soil properties to re-estimate more accurate pile sizes and penetration depths.

3.4 Pipeline system

An expanded pipeline network is planned, based on free-flowing wellstream fluids to shore, and returning gas lift gas (GL) and reinjection water (WI) to the platforms.

The pipeline network, including the 20" stabilised oil export line, is shown as Figure 37

Initially, the existing 12" and 10" pipelines will convey production from R-10 and R-17 platforms respectively. After the completion of platform R-B and the short 2 km line from R-B to nearby R-10, R-B production will also free-flow down the 12" line.

Platform R-C will be installed alongside R-17, and connected to R-17 by a short bridge, over which R-C production will be conveyed to R-17 and into the R-17 to shore 10" line. (Note that the ability to bridge connect R-C and R-17 will have to be confirmed by detailed study.)

Platforms R-A and R-D will share a common new 16" line to shore.

Reservoir analysis has determined that water injection and gas lift will be necessary in order to maximise recovery of oil from the Ravva Field. Consequently, water injection and gas lift pipelines will be installed early in the life of the field in order to help maintain reservoir pressure and to assist production as water cuts increase.

The water injection pipeline system will be designed for a delivery pressure of 400 psig at each platform having water injection wells. Actual required injection pressure at the wellhead is likely to be lower than 400 psig, but this design criteria allows for lower-than-anticipated injectivity. Expected onshore plant discharge pressure is 585 psig.

The gas lift pipeline system will be designed to supply gas lift gas to each platform at 1200 psig at the wellhead. This supply pressure will be more than adequate to allow wellbore unloading and sustained gas-lift-assisted oil/gas/water production as decline advances. Expected plant discharge pressure is 1345 psig.

All pipeline hydraulics (calculation of which are included in Appendix 2) have been checked for adequacy based on the production volume profiles shown on Figure 29. For both the initial flowing conditions and for extremely high water cuts near the end of the life of the field, the proposed diameters in the pipeline network are sufficient to free flow the fluids to shore for separation and treatment. Pipeline calculations will be verified when reliable fluid properties are available.

Assumed well fluid pipeline operating conditions are.

Year	*Flowing Wellhead Pressure (psig)*	*Plant Inlet Pressure (psig)*
1	1,000	>>900
16	250	200

By using a free flow approach, production system reliability will be high since complexity of offshore facilities will have been reduced to minimal levels

The oil export line will be installed as quickly as possible, to allow an early increase in production from the existing level of 3,000 bopd, determined by the ability to truck oil to the Vizag refinery 200 km to the north.

Pressure drop in the oil export line at the maximum loading rate of 10,000 barrels per hour is estimated to be 70 psig. Allowing for a further loss of 15 psig through the SPM loading hoses, a pipeline inlet pressure of 85 psig has been allowed for when sizing the export pumps.

All pipelines will be adequately weighted for seabed stability Effective corrosion protection will be provided, as will a corrosion allowance

3.5 Processing and Storage

A complete well fluid analysis was not available for the preparation of this plan The design of the processing facilities has consequently been based on an assumed well stream which conforms to the observed gas-oil ratio. In designing these new facilities it has been assumed that there will be no benefit from the existing facilities

Subject to receipt of a full wellstream analysis the onshore processing facilities are envisaged to be as represented in Figure 38. The well fluids will be fed onshore to the slug receiver operated at 150 psig. This vessel will act as both the slug receiver to minimise the effect of potential slug flow in the pipeline on the downstream equipment, and as the primary liquid/gas separator. Lift gas and fuel gas for the facility will be taken from this vessel. The liquid stream from this vessel will be heated prior to passing to the production separator. The required operating temperature for this separator will depend upon the temperature of the fluid reaching the separator, demulsifiers and residence time. The experience already acquired in operating the existing facilities will be very valuable in determining the correct operating temperature, but for the purposes of this plan has been assumed to be between 50 and 60°C.

The production separator, which will be operated at a pressure of 45 psig, will be sized to allow 10 minutes residence time.

Oil from the production separator will be cooled before going to a stabiliser vessel to allow venting of any associated vapour and is then pumped to the existing intermediate storage tanks.

Produced water from the production separator will be cleaned in an induced flotation unit followed by a corrugated plate interceptor, before being re-injected into the reservoir. The design allows for an offshore outfall to be added to the facilities at a later date should this be necessary.

Two 250,000 barrel floating roof storage tanks (Figure 39) will be used to store stabilised crude. Gas fuelled loadout pumps, rated for pumping 10,000 barrels per hour, will transfer the crude to tankers via the loading line and SPM.

An equipment list of facilities to be provided is contained in Table 10.

3.6 Water Injection and Gas Lift Facilities

3.6.1 Water Injection Facilities

The water injection facility will be installed during Phase 2 of the development. It will be a modular unit with a capacity of 60,000 barrels per day, and will be able to :-

- remove suspended solids to prevent plugging;
- remove dissolved oxygen to prevent aerobic bacteria growth and biofouling in both the formation and the injection piping and tubing;
- dose the water with scale and corrosion inhibitors and bactericides; and
- pressurise the water to well injection pressure after allowing for pipeline friction drop.

The facility has been sized and costed based on similar capacity units. Its principal specifications are :-

- wellhead pressure : 400 psig
- suspended solids : < 0.1 mg/L
- dissolved oxygen : < 0.005 mg/L

Process Flow Diagrams (Figures 40 and 41) present the overall water facility and a typical water injection unit that would be appropriate for the Ravva Field development. When required, ground water from two or more onshore water wells or treated produced water is pumped to the unit. The water is initially filtered through Coarse Filters, then media filters and finally cartridge filters to remove all particles greater than 0.5 microns. The filtered water is then deaerated to remove dissolved oxygen in the vacuum deaerator and then pressurised to the required injection pressure by the extract/booster pumps and the injection pump. The water is also dosed with hypochlorite from the electrochlorinator, oxygen scavenger, defoamer, corrosion inhibitor, biocide, and inhibitor.

3.6.2 Gas Lift Facilities

The gas lift facility is designed to compress and dry up to 10 MMscfd of gas from the slug receiver to 1250 psig for an injection pressure of 1200 psig. The facility will not be installed until Phase 3 or year 3 or at least 4 of the development.

Process Flow Diagram (Figure 42) presents a typical gas compression and dewpoint control unit for the Ravva Field development. A Solar Saturn T-1500 turbine/compressor package has been assumed. The compressor package will consist of a compressor scrubber, a Solar Saturn turbine/compressor and a gas cooler. This unit will compress the gas from 150 psig to 1250 psig and cool it to 60°C.

The compressed gas will not be a "dry" gas. It is probable that hydrocarbon liquids and water will condense in the gas lift pipelines. To avoid this, a refrigeration unit to reduce the compressed gas dewpoint to at least 5°C below the minimum seabed temperature is included. The unit has been sized assuming a minimum seabed temperature of 20°C. The unit consists of a hot wet gas/cold dry gas exchanger, an evaporative cooler, knockout drum and refrigeration unit.

All drive units apart from the Solar Saturn gas turbine are electric.

3.7 Crude Oil Transportation

The stabilised crude will be transferred to tanker via a SPM buoy located approximately 15 km offshore in a water depth of approximately 40m (Figure 43). This depth of water has been selected to reduce the loads on the buoy and tanker when a tanker is moored during rough weather. In shallow water these loads would be greater and the amount of time that loading would have to be curtailed due to weather would increase. The buoy will be designed to moor tankers up to 120,000 DWT (offtake loads up to 750,000 barrels) and the oil will be delivered to the buoy by a 20" oil export pipeline coated with 2" of concrete.

Prior to completion of the onshore storage tanks it is proposed that two 20,000 to 30,000 DWT (120,000 to 180,000 barrels) shuttle tankers will be used. One tanker will be moored at the SPM and loaded at the field production rate; when it is full it will be replaced by the second tanker. During change over production will be to the existing 3 x 6,000 barrel storage tanks. In long periods of bad weather it may not be possible for a tanker to remain at the mooring in which case production will have to be curtailed. Use of the shuttle tankers is expected to be for less than 12 months.

Mooring of tankers will be assisted by the service vessel which will be on permanent charter to the operation.

3.8 Formation Water Reinjection/Disposal

After separation and cleaning, produced formation water will be supplied to the water reinjection treatment and pumping system for re-transmission offshore and reinjection into the reservoir. Treatment of reinjection water will comprise suitable filtration as described in Section 3.6.1.

In the event that formation water surplus to reinjection needs is produced facilities can be added later which will provide for this water to go to a small holding pond from where it will be pumped by low head water pumps through a short outfall to the ocean.

3.9 Corrosion Control

3.9.1 External Corrosion

Platforms and sub-sea pipelines will be coated with suitable corrosion protection and sufficient additional steel to allow the facilities to achieve their design life of 20 years.

3.9.2 Internal Corrosion

Well tubulars, pipelines process facilities and storage tanks will be susceptible to internal corrosion due to the presence of CO_2 in the wellstream and possibly infection of the system by sulphate reducing bacteria ("SRB"). CO_2 corrosion will be controlled by injecting suitable inhibitors downhole. A monitoring programme to detect the presence of SRBs will be established early in the life of the field, and if SRBs are discovered appropriate action will be taken.

3.10 Hydrate Control

Suitable hydrate inhibition will be provided for the gas lift injection system. The gas will be lean enough at the discharge from the plant to avoid liquids entrainment/slugging problems in the gas lift system. For emergency

purposes, hydrate inhibitor stocks will be kept on hand at the plant for injection into the gas lift line if required.

3.11 Development Schedule

The proposed development work will be conducted in three phases. These phases are represented in Figures 44 to 46 inclusive. Achievement of these schedules will be dependent upon timing in respect of the monsoon season, during which no offshore construction work can take place, and the timely awarding of contracts and procurement of materials.

3.11.1 Phase I : 0-14 Months

- install loading line and SPM;
- install R-B;
- drill six development wells;
- lay well fluids flow line from R-B to R-10; and
- install Phase I additional onshore process facilities.

This phase, which will result in a production capacity of approximately 30,000 bopd (depending on actual well productivity achieved), is expected to be completed within 14 months of award of contract.

3.11.2 Phase 2 : 0-21 Months

- installation of R-A, R-C, and R-D platforms;
- drilling of 12 production and water injections wells;
- installation of 16" well fluid line and 10" water injection line;
- construction of two 250,000 bbl storage tanks;
- addition of Phase 2 onshore process facilities; and

- installation of water injection facilities.

This phase is expected to be completed within 21 months of award of contract at which time the field's maximum production rate of 50,000 bopd will be achieved. This plateau production rate is expected to last for 21 months before starting to decline.

3.11.3 Phase 3 : 24-36 Months

- installation of gas lift facilities including gas lift pipeline.

This phase is scheduled to be completed within 12 months of obtaining maximum production rates. However, actual timing will depend on observed performance of the field and preliminary estimates indicate that gas lift will not be required for several years.

4 DRILLING AND COMPLETION PROGRAMME

It is intended to drill 18 additional production and injection wells from the four wellhead monotowers to be installed, and possibly from the existing R-10 and R-17 structures already installed. These wells will be a mixture of vertical and directionally drilled wells with the maximum hole angle of the deviated wells kept to less than 60° in order to prevent difficulties when operating with wireline.

The proposed programme is acknowledged as being conservative. Once data from wells already drilled has been received this programme will be optimised with the intent of either reducing the size or number of casing strings to be installed. A possible alternative drilling programme is described in Section 4.2 below.

4.1 Drilling Programme

4.1.1 Conductor String

In order to restrict waveloading on the wellhead towers 26" conductors will be used. These will be driven to a depth of approximately 140m below rotary table. This is equivalent to a penetration of 110m below seabed which is 10m below the monotower pile tip. At this time it is intended that these conductors will be installed by the derrick barge at the time of installation of the montower as the barge could accomplish this task more efficiently than a drilling rig. This will however depend upon the schedule of the barge.

4.1.2 Surface Casing

In view of the unconsolidated nature of the surface sediments, a 18⅝" surface casing will be set at approximately 400m in a 24" hole. The 20" BOPs will be installed after setting the 18⅝" casing.

4.1.3 Intermediate Casing

A 13⅜" casing will be installed at approximately 1,200m T.V.D. In the case of the deviated wells it is intended that the build-up section of the well will be drilled in the 17½" hole. By installing 13⅜" casing this build-up section will be protected, and the running of open hole electric logs through the pay will be easier.

4.1.4 Production Casing

A 12¼" hole will be drilled to the planned total depth of 1,800m T.V.D. At this depth a minimum suite of open hole logs will be run before installing the 9⅝" production casing. While drilling this section particular emphasis will be given to management of the mud system to ensure good hole conditions prevail, allowing the acquisition of good quality open hole logs.

4.2 Alternative Drilling Programme

Subject to more detailed studies it is possible that the following drilling programme could be used :-

- drive 26" conductors to 140m;
- drill 17½" hole to 1,000m T.V.D. and set 13⅜" surface casing. The well would be deviated in this section.
- drill 12¼" hole to 1,800m T.V.D. and set 9⅝" production casing.

Advantages of this programme would be :-

- by omitting the 18⅝" casing the time to drill a well will be reduced by two days and a total saving of approximately $250,000 per well would be realised;
- by kicking the well off higher up the maximum well angle will be lower, reducing the problems of using wireline for completion work; and
- this programme still allows the use of 9⅝" casing as the production string. This is important for maintaining maximum flexibility in the design of the completion string.

The critical feature of this alternative programme will be determining the risks of omitting the 18⅝" surface casing. If it is possible total savings of approximately $4.5 million are realisable.

4.3 Completion Programme

Detailed completion programmes will be prepared after review of all data, however, it is likely that a standard completion for an oil production well will have the following features :-

- completion tubing is likely to be 4½" in diameter;
- down hole injection facilities will be available for the injection into the well stream of corrosion inhibitors and any other chemicals required to optimise production. Some internal corrosion is likely in view of the 1.5% CO_2 present in the associated gas;
- gas lift mandrels will be installed at appropriate depths in anticipation of the requirement to provide artificial lift to wells once they have reached a certain level of water cut;
- down hole safety valves will be installed approximately 300m below the mudline; and
- Xmas trees with a 3,000 psi rating and fitted with two master valves and one wing valve, will be installed. One of the master valves will be fitted with a fail-safe hydraulic actuator.
- use of 9⅝" casing as the production casing will allow the dual completion of wells with multiple zones.

The specific design of the water injection wells will be determined after review of all reservoir data.

4.4 Predicted Drilling Times

The time to drill and complete typical wells, both vertical and deviated, has been estimated by Command and the results are summarised in Table 11. The average well is estimated to take 22 days to drill and complete. A predicted drilling time curve has been prepared and is shown in Figure 47.

4.5 Drilling and Completion Costs

The cost of drilling and completing a well of average deviation is estimated to be $2.4 million (Table 12). As additional information becomes available it is anticipated that this cost will reduce. In particular the following areas will be examined to optimise the drilling :-

- batch drilling of 18⅝", 13⅜" and 9⅝" results in considerable efficiencies. Further savings can be made if all wells are completed at one time;
- wellhead design is important to minimise the time spent installing this item of equipment;
- a properly designed mud and hydraulics programme will be necessary to maximise penetration rate and hole stability. Careful attention will need to be given to the mud cleaning;
- access to a nearby shorebase for supply of drilling materials will help to reduce boat and fuel costs;
- modern PDC bits, if carefully applied, can have significant beneficial effects on penetration rates; and
- consideration will be given to using a workover rig to complete the wells. Savings could be realised from sharing of boats and helicopters, and maintaining the more expensive drilling rig in a drilling mode.

It is difficult to determine the overall cost reductions that can be achieved, especially as significant improvement will evolve as the programme progresses. However, savings of up to 15% may be achievable, reducing the costs of a well by approximately $350,000 to approximately $2.1 million.

4.6 Rig Selection

The well cost estimates have been based on using a non-Indian rig from southeast Asia. A cost of $500,000 has been allowed for mobilisation. However, the work will be tendered to both Indian and non-Indian rigs and

while final selection will be based on both commercial and technical considerations, an Indian rig will be preferred.

Assuming a total of 18 wells at an average cost of $2.4 million each, drilling is the largest total cost item of the project and therefore offers the most scope for reduction in costs. This reduction will be realised by adopting the optimum drilling programme and using a rig which is not only reliable but is equipped with superior mud cleaning equipment to handle the anticipated high drilling rates, and preferably a top-drive which will greatly increase the efficiency of drilling deviated holes. Given the size and length of the anticipated programme, selection of the "best" rig will be an important part of Command's efforts to reduce the cost of the development of the Ravva Field.

5 OPERATING PLAN

5.1 Operating Philosophy

The four basic objectives of the operating philosophy will be as follows :-

- maximise safety of personnel and facilities;
- optimise production rates such that recovery of the oil is maximised in the shortest time; and
- minimise the impact of the project on the environment;
- minimise costs.

The offshore facilities will be designed to run safely unmanned, with visits for inspection, maintenance and well testing being facilitated by boat or helicopter. Heavy items, such as wireline units for well servicing work, will be delivered by underslinging from the helicopter. In this way pressure surveys, tubing inspections and downhole safety valve servicing will be accomplished easily and cheaply. Major workovers will require the use of a jack-up drilling rig.

Fail-safe well shut down facilities will be provided on each WHT with monitoring of well status onshore via radio telemetry or another reliable method.

The onshore facilities will be permanently manned with 24 hour per day monitoring of the stabilisation plant, water injection pumps, gas lift compressor and storage tanks. Subject to final design, it is envisaged that manning levels will be as follows :-

- production supervisor 1
- production operators 14
- maintenance 6

Additional personnel will be required for major maintenance tasks and for wireline operations.

5.2 Personnel

Whenever feasible Indian personnel will be employed. It is envisaged that Command will only employ up to three expatriate people in India. These will be the General Manager and one other senior member of staff located in Madras, and one Production Supervisor located on site. All other personnel will be Indian nationals.

Employment of production personnel will commence immediately following contract award so that training and familiarisation can be completed prior to the commencement of maximum production rates.

The proposed personnel organisation for the production phase is shown in Table Figure 48.

5.3 Environment Management Philosophy

5.3.1 General

In preparing this philosophy Command has drawn on its experience offshore Western Australia, where it operates two exploration permits in shallow water surrounded by environmentally sensitive areas such as coral reefs, and fishing grounds. In operating these permits Command has a track record of meeting or exceeding the strict environmental conditions laid down by the Western Australian Government, and intends to exercise the same environmental care if awarded the contract to develop the Ravva Field.

5.3.2 Monitoring

Subject to a review of existing environmental studies, it is proposed to conduct a base line study to determine the nature of the environment and habitat in the area of the operations (including onshore and the pipeline shore crossing) and to identify areas which would be at risk from an oil spill prior to commencing any further development work. Monitoring will then be conducted on an annual basis and any changes to the environment will be noted and advised to the appropriate authorities.

5.3.3 Oil Spills

These can be divided into three categories :-

- small <5 tonnes;
- medium 5 to 20 tonnes; and
- large >20 tonnes.

Small spills might occur during tanker loading or well servicing operations. The oil from such spills is expected to evaporate in a few hours and no action would be taken other than to monitor the location of the oil.

Medium spills can occur if a pipeline was to rupture. In this case booms would be deployed and dispersants applied to prevent the oil approaching a shoreline.

Large spills, which might be the result of a well blowout or the running aground of a tanker, would probably over extend the capability of the facilities maintained on site, and outside assistance would be required to control and clean up the spilled oil.

Prior to commencement of operations an "Oil Spill Contingency Plan" would be developed. Training of personnel in the use of equipment and the conduct of exercises would be part of this plan.

5.3.4 Water Disposal

All produced waters will be brought onshore, and much of it used for re-injection. Any surplus water will be disposed of to the ocean via a line run a suitable distance offshore.

5.4 Safety

In all of Command's operations safety is paramount.

The use of onshore processing facilities and unmanned platforms makes the development inherently safe. Operation of similar facilities offshore Western

Australia has demonstrated that low injury frequency rates can be achieved and that personnel are not exposed to catastrophic type accidents.

The risk of injury to personnel will be greatest when operating the plant and when transferring onto and off the platforms. With suitable training it is believed that the frequency of injury will be minimised. The importance of safety and safe operating practices will be emphasised at all times during the operation of the field

Prior to commencement of operations, Command will prepare detailed Emergency Response procedures for various emergencies including fire, blowout and helicopter ditching.

5.5 Supply Base

A supply base as close to the field as possible is required for handling he service vessel and warehousing supplies for the operation. The actual location of this base will depend on land availability and environmental considerations. This matter will be further evaluated during a forthcoming site visit by Command personnel.

Ideally this base would be of sufficient size to support the drilling operations. For this purpose greater water depth (for the larger boats servicing the jack-up rig), a larger jetty and more land would be required. The decision to expand the supply base for this purpose will be based on the increased cost of building it, versus the cost of using alternative more distant bases.

5.6 Service Vessel

This vessel will perform the following tasks :-

- transport personnel and equipment to and from platforms;
- provide assistance for mooring of tankers (if necessary);
- be fitted with oil spill containment booms and dispersant spray equipment; and
- perform as a diver support vessel when required.

This vessel will need to be relatively fast in order to minimise the transit time between the shore base and the platforms, will need sufficient deck space for the deployment of oil spill booms and performing diver support services, and be of shallow draft to allow access to the supply base.

5.7 Platform Access

It is envisaged that it will not be possible to rely entirely on the service vessel to obtain access to the wellhead towers. This will be particularly true during the monsoon season. In addition, evacuation of injured personnel and transportation of heavy lift items, such as wireline units, would be very difficult without the use of a helicopter.

If a platform is shut-in, and boat access to the platform is not possible, the consequent loss of revenue could be significant especially during the early years of production.

In view of this potential loss of revenue, the significant increase in safety, and the improved ease of operation that will result from having helicopter support, it is proposed that a helicopter be chartered on a permanent basis.

6 COSTS

6.1 Introduction

Cost efficiency is considered by Command to be critical to the success of the project.

Cognisant of this, and of the desire by all parties to maximise their return from the Ravva Field, Command has placed a heavy emphasis on developing a low cost plan. Each component has been, and will be again, subjected to thorough analysis to ensure that it has been designed "fit for purpose"; i.e. there will be no items that are not strictly necessary for the field to be developed in a safe and efficient manner.

The capital and operating costs of the proposed development have been prepared by Command with assistance from Worley. Preliminary engineering design of the platforms, pipelines, process, storage and tanker loading facilities has been completed. This design work has permitted sizing of all components and, using an extensive industry data base, has allowed a reasonably accurate cost to be placed on each of the facilities. Spot checks with pipe mills and suppliers of services (derrick barges, etc.) have served to verify Worley's cost estimates.

In accordance with the standard industry practice in relation to projects at this stage, a contingency of 20% has been applied to the construction components of the development. This is appropriate given the level of engineering which has so far been completed.

The total construction cost has then been compared with the cost to develop similar sized fields offshore Australia which are located in similar environmental conditions (shallow waters exposed to cyclonic storms) (Appendix 1). Despite the costs for the Ravva Field being similar Command has added a further 10% contingency which is required to cover potential delays in the schedule and other unpredictable events.

It is important to note however, that these costs exclude any import duty, which, if applicable to this project, could increase these costs by as much as 25%.

The cost to drill and complete the wells has been based on an assessment of the time required to drill a typical well (22 days) and the tangible cost to complete it. The assumed cost of hiring a jack-up drilling rig is higher than the current prevailing rate in India, but is considered appropriate in view of the

equipment specification which a rig would need to have in order to drill these wells efficiently. The higher cost also provides some cushion in the event that rig rates increase over the next six to twelve months.

The cost of drilling includes an appropriate level of contingency in that extra time has been allowed for each well and no benefit has been allowed from the inevitable efficiency that will occur during the year long drilling programme.

Given the above approach to estimating the cost of developing the Ravva field, Command is confident that the costs detailed below are conservative, are unlikely to exceed $170 million, but could, with good management, be reduced.

6.2 Capital Costs

The capital costs, excluding import duty, for each phase of the project are summarised in Tables 13 to 15 inclusive. The detailed derivations of these summaries are presented in Tables 16 to 28 inclusive. Table 29 is an anticipated cash requirement schedule during the first three years of the project.

6.3 Operating Costs

Typical annual operating costs, which are estimated to total about $12 million (excluding import duty), are presented in Table 30.

6.4 Abandonment Costs

Abandonment costs have been estimated on the following basis :-

- wells will have their completions removed, perforations plugged off and casing strings cut off just below the mud line.
- platform piles will be cut off just below the mud line and platforms removed.
- pipelines will be flooded with seawater and left on the seabed
- SPM will be removed including anchors and chains.

- onshore processing and storage facilities removed and site cleared.
- nil salvage value.

Abandonment costs are detailed in Table 31

7 MANAGEMENT

7.1 General

The development, and operation of the Ravva Field will be managed by Command personnel based in Madras and on site, and it is intended that the numbers of national Indian personnel will be maximised and only a small number of expatriates (up to three) will be employed. This office will be responsible for managing the field and ensuring the resource is recovered in the most optimum fashion.

Command's General Manager of this project, who will report to the Project Manager in Sydney, will be the Chairman of the Management Committee as designated in the Production Sharing Contract, and will be responsible for ensuring that the project is managed in accordance with the requirements of the PSC, and that the Joint Venture Operating Agreement directions are followed

Adherence to Command's safety and environmental policies will be the responsibility of the Command Manager.

7.2 Project Management

It is intended that management costs of the development project will be minimised by following these guidelines :-

7.2.1 Standard Contracting Philosophy

All fabrication and installation work will be carried out in accordance with standard codes and practices, well known to the offshore construction industry, and there will be an absence of exotic materials. As a consequence of this it is believed that tenderers will be able to minimise the cost of fabricating and installing the facilities, and that the cost of quality control can be reduced.

7.2.2 Turnkey Contracts

Wherever possible turnkey contracts will be used for the fabrication and installation of the major facilities. Typically such a contract would be the installation of the 20" tanker loading line and SPM where a single contractor would be contracted to procure, deliver, install and commission the tanker loading facilities. Management of such a contract is minimised involving only some quality assurance and

quality control from Command, with no contractor interface, which is often an area for additional claims.

The turnkey contracts will make the contractor responsible for weather down time (except cyclones), and procurement of all materials.

Not only will project management costs be minimised, but the possibility of costs increasing during the course of the project will be reduced by adopting these contracting procedures.

7.3 Tendering and Procurement

The purchase and procurement of all materials and services not covered by turnkey contracts will be managed by Command's Madras office. Detailed procedures will be prepared covering the processes of requisitioning, purchasing and expediting of materials and services.

In order to achieve the schedule set out in this plan it will be necessary to award contracts for the procurement and fabrication of the facilities as soon as possible. Detailed tendering procedures will be prepared based on the following assumptions :-

- suitably qualified Indian and non-Indian companies will be invited to tender.
- tenders will initially be received by Command's Project Manager in the company's Sydney, Australia, office as it is anticipated that it will take some time to establish the Madras office.
- after receipt of tenders no further negotiations will be entered into, other than discussions between Command and tenderers in order to clarify details of the tender.
- tenders will be evaluated on both commercial and technical bases.
- for contracts worth more than a certain value, which will have to be agreed by the Joint Venture participants, Command will

seek the approval of the Joint Venture to award a contract. Each contract will be between Command, on behalf of the Joint Venture, and the contractor

8 GLOSSARY

2D	Two dimensional seismic data
3D	Three dimensional seismic data
BBL	Barrel
BCF	Billion cubic feet
BOPD	Barrels of oil per day
CDP	Common-depth point (multi fold seismic data)
DMO	Dip move out
FVF	Formation Volume Factor
GIP	Gas in place
GM	Gravity-magnetics
GOC	Gas-Oil Contact
KB	(relative to) Kelly bushing
km	Kilometre
km^2	Square kilometres
m	Metre
m^3	Cubic metres
mBMSL	Metres below mean sea level
MMm^3	Million cubic metres
MMBBL	Million barrels
MSD-1	Reservoir sand unit
msec	Milliseconds
MSFL	Micro-spherically focussed resistivity log (shallow investigation)
NE-SW	Northeast-southwest
NW-SE	Northwest-southeast
OIP	Oil in place
ONGC	Oil and Natural Gas Commission (of India)
psi	Pounds per square inch
PVT	Pressure, Volume, Temperature analysis
R-9	Well, Ravva-9
RFT	Repeat Formation Test
Ro	Resistivity of water saturated sand
Rt	Resistivity (deep)
SCF	Standard cubic foot (of gas)
So	Oil saturation
SP	Spontaneous potential
STB	Stock tank barrel
STkl	Stock tank kilolitres
Sw	Water saturation
SWC	Sidewall core
Sxo	Oil saturation, flushed zone
TVD	True vertical depth
TWT	Two way time

RAVVA FIELD, OIL-IN-PLACE AND RECOVERABLE RESERVES

CONFIDENCE LEVEL		PROVEN "1P"	PROVEN PLUS PROBABLE "2P"	PROVEN PLUS PROBABLE PLUS POSSIBLE "3P"
OIL-IN-PLACE :-				
BLOCK R10	MMT	13 6	15 9	18 4
	MMBBL	101 0	118 0	136 5
BLOCK R17	MMT	9.8	11 5	13.7
	MMBBL	72 6	84 9	101 4
COMBINED BLOCKS	MMT	24 3	27 5	30 8
	MMBBL	180 0	203 7	228.2
RECOVERY FACTOR	%	41	50	59
RECOVERABLE RESERVES :-				
BLOCK R10	MMT	6 3	7 9	10.0
	MMBBL	46 4	58 6	74 2
BLOCK R17	MMT	4 5	5 7	7.2
	MMBBL	33 1	42 3	53.6
COMBINED BLOCKS	MMT	10 9	13 6	16 9
	MMBBL	80 5	101 0	124 9

Please note .

The figures shown for the 'Combined Blocks' have been derived by combining probabilistic determinations and therefore these figures do not necessarily equal the sum of the separate figures quoted for Block R10 and Block R17.

Table 1

RAVVA FIELD, BLOCKS R10 AND R17 FLUID PROPERTIES

WELL	PERFS (MKB)	PRESSURE (PSI)	OIL FORMATION VOLUME FACTOR (VOL/VOL)	GAS FORMATION VOLUME FACTOR (VOL/VOL)	SOLUTION GAS-OIL RATIO (VOL/VOL)	OIL VISCOSITY (CP)
R-10	1676-80	2580	1 2195		50 44	0 74
		1640	1 2428	n a	50 44	0 67
		1300	1 2105	0 01436	50 30	0 73
		1000	1 1847	0 01504	41 07	0 78
		700	1 1587	0 02688	30 80	0 96
		400	1 1386	0 04771	21 71	0 92
R-10	1637-39	3000	1 2410		75 07	0 68
		2536	1 2500		75 07	0 65
		2000	1 2580		75 07	0 61
		1970	1 2610	n a	75 07	0 60
		1500	1 2190	0 01163	57 56	0 68
		1200	1 1990	0 01496	48 67	0 72
		900	1 1650	0 02021	36 83	0 80
R-10	1592.5-94 5	3000	1 2200	.	74 98	0 72
		2512	1 2260	.	74 98	0 70
		2200	1 2320		74 98	0 68
		1990	1 2370	n a	74 98	0 66
		1500	1 1850	0 01170	56 86	0 75
		1200	1 1620	0 01481	48 89	0 80
		900	1 1380	0 01989	38 74	0 86
R-12	1697-1706	2601	1 1570		58 74	1 02
	1737-43	2200	1 1620		68 74	0 98
		1800	1 1670	.	68 74	0 94
		1630	1 1760	n a	68 74	0 92
		1200	1 1610	n a	57 16	0 98
		800	1 1300	n a	42 00	1 12
R-27	1666-70	2600	1 2878		81 38	0 38
	1676-83	2230	1 2940	n a	81 38	0 36
	1688-94	1800	1 2589	0 00877	66 84	0 42
		1400	1 2251	0 01219	53 10	0 43
		1000	1 1972	0 01707	39 82	0 45
		600	1 1602	0 02856	26 70	0 50

RAVVA FIELD, BLOCKS R10 AND R17 WELL TEST SUMMARY

WELL	PERFS (MKB)	CHOKE SIZE	DUR'N (HRS)	OIL RATE (BOPD)	GAS-OIL RATIO (VOL/VOL)	TUBING PRESSURE (PSI)	DOWNHOLE PRESSURE (PSI)	REMARKS
R-10	1676-80	16/64	0 2			766		Pressures P1/P2 are SPRO @ 1617 mKB
		S/I	2 0				2555/2612	and ONGC gauge @ 1673 mKB
		16/64	14 0	600	57	977	2521/2573	
		S/I	11 0				2536/2589	Interpretation - k = 3 9 Darcys
		20/64	8 5	1050	56	960	2502/2561	h = 23 ft
		24/64	9 0	1505	67	979	2478/2541	S = 26
		32/64	13 0	2900	61	930	2443/2513	P* = 2536 psi
		S/I	7 0				2527/2578	@ 1617 mKB
R-10	1637 39	16/64	0 7			784		Pressures P1/P2 are SPRO @ 1585 mKB
		S/I	2 0				2567/2622	and ONGC gauge @ 1630 mKB
		16/64	9 0	660	69	998	2489/2546	
		S/I	26 0				2495/2547	Interpretation k = 6 0 Darcys
		20/64	8 0	1050	78	1010	2478/2531	h = 22 ft
		24/64	6 5	1540	75	1007	2456/2515	S = 33
		32/64	8 0	2930	64	945	2398/2475	P* = 2502 psi
		S/I	8 5				2499/2543	@ 1585 mKB
R-10	1592 5-94 5	16/64	0 2			220		Pressures P1/P2 are SPRO @ 1538 mKB
		S/I	2 0				3022/3067	and ONGC gauge @ 1583 mKB
		16/64	11 5	625	74	956	2382/2422	
		S/I	5 5				2462/2497	Interpretation k = 5 9 Darcys
		20/64	8 0	1040	79	978	2386/2420	h = 39 ft
		24/64	5 0	1482	74	956	2335/2378	S = ?
		32/64	9 5	2660	65	873	2240/2294	P* = 2462 psi
		S/I	6 0				2452/2481	@ 1538 mKB
R-12	1697 1706	16/64		662	67	1007		Interpretation k = 3 4 Darcys
	1737-43	20/64		1102	64	1037	2406	h = 56 ft
		24/64		1638	70	995	2376	S = 75
		32/64		2696	62	910	2282	P* = 2444 psi
		S/I				1086	2443	@ 1547 mKB
R-17	1679-82	16/64	0 2					Pressures are @ 1648 mKB
	1687-90	S/I	2 0				2564	
	1695-97	16/64	15 5	901	39		2546	
	1704-06	S/I	2 0				2564	Interpretation k = 4 2 Darcys
		20/64	11 2	1278	31		2528	h = 130 ft
		24/64	9 0	1667	35		2494	S = 260
		32/64	14 0	2393	34		2445	P* = 2564 psi
		S/I	26 0				2564	@ 1648 mKB
		48/64		3998	35			
R-27	1668-70	16/64	0 2					Pressures P1/P2 are Amerada @ 1648 mKB
	1676-83	S/I	2 0					and MUST gauge @ 1608 mKB
	1688-94	16/64	14 3	690	70		2561/2470	
		S/I	10 0				2546/2504	Interpretation k = 1 7 Darcys
		20/64	10 5	1464	61		2518/2419	h = 165 ft
		S/I	8 0				2543/2504	S = 290
		24/64	6 0	2309	76		2497/2351	P* = 2504 psi
		S/I	8 0				2541/2504	@ 1608 mKB
		32/64	6 5	2804	73		2457/2225	
		S/I	22 5				2541/2504	

RAVVA FIELD, "TYPICAL WELL" PRODUCTION FORECAST

YEAR	OIL PRODUCTION RATE (BOPD)	WATER PRODUCTION RATE (BWPD)	TOTAL FLUID PRODUCTION RATE (BFPD)	PRODUCING WATER CUT (%)	CUMULATIVE OIL PRODUCTION (MMBBL)
1	6,000	0	6,000	0.0	2.19
2	6,000	0	6,000	0.0	4.38
3	3,500	500	4,000	12.5	5.66
4	2,570	1,430	4,000	35.8	6.60
5	1,870	2,130	4,000	53.3	7.28
6	1,350	2,650	4,000	66.3	7.77
7	980	3,020	4,000	75.5	8.13
8	710	3,290	4,000	82.3	8.39
9	520	3,480	4,000	87.0	8.58
10	380	3,620	4,000	90.5	8.72
11	270	3,730	4,000	93.3	8.81
12	200	3,800	4,000	95.0	8.89
13	150	3,850	4,000	96.3	8.94

RAVVA FIELD, PRODUCTION, INJECTION AND GASLIFT FORECAST

PERIOD	OIL PRODUCTION RATE (BOPD)	WATER PRODUCTION RATE (BWPD)	TOTAL FLUID PRODUCTION RATE (BFPD)	PRODUCING WATER CUT (%)	CUMULATIVE OIL PRODUCTION (MMBBL)	REQUIRED WATER INJN RATE (BWPD)	ACTUAL WATER INJN RATE (BWPD)	REQUIRED GAS LIFT GAS RATE (MMSCF/D)
EARLY YEARS BY QUARTER -								
1Q93	0	0	0	n a	0 00	0	0	0 00
2Q93	3,000	0	3,000	0 0	0 27	0	0	0 00
3Q93	3,000	0	3,000	0 0	0 55	0	0	0 00
4Q93	3,000	0	3,000	0 0	0 82	0	0	0 00
1Q94	3,000	0	3,000	0 0	1 10	0	0	0 00
2Q94	6,000	0	6,000	0 0	1.64	0	0	0 00
3Q94	12,000	0	12,000	0 0	2 74	0	0	0.00
4Q94	24,000	0	24,000	0 0	4.93	0	0	0 00
1Q95	30,000	0	30,000	0.0	7.67	0	0	0.00
2Q95	40,000	0	40,000	0 0	11 32	52,000	60 000	0.00
3Q95	50,000	0	50,000	0 0	15 88	65,000	60 000	0 00
4Q95	50,000	0	50,000	0 0	20 44	65,000	60 000	0 00
FULL FORECAST BY YEAR -								
1993	2,250	0	2,250	0 0	0 82	0	0	0 00
1994	11,250	0	11,250	0 0	4 93	0	0	0 00
1995	42,500	0	42,500	0 0	20 44	45,500	45,000	0 00
1996	50 000	839	50,839	1 7	38 68	65,839	60,000	0 00
1997	47 330	5,919	53,249	11 1	55 97	67,448	60,000	0 00
1998	36,476	14,732	51,209	28 8	69 28	62,152	60,000	0 46
1999	25 427	23,915	49,342	48 5	78 56	56,871	60,000	3 46
2000	18 471	30,955	49,426	62 6	85 30	54 967	60 000	6 49
2001	13 376	36,011	49,387	72 9	90 18	53,400	60 000	7 84
2002	9 240	40,125	49,365	81 3	93 56	52,137	53,413	8 97
2003	6,862	42,453	49,315	86 1	96 06	51,373	51,373	9 56
2004	4,914	44,412	49,326	90 0	97 86	50,800	50,800	10 05
2005	3,551	46,680	50,231	92 9	99 15	51,296	51,296	10 39
2006	2,486	45 281	47,768	94 8	100 06	48,514	48,514	10 42
2007	1,774	42,408	44,181	96 0	100 71	44,713	44,713	9 90
2008	564	14,477	15,041	96 3	100 91	15,210	15,210	3 62

Command Petroleum, July 1993

C:\OPW\RAVTAB5.WB1 (EB)

Table 5

Monthly Average Rainfall at Kakinada

Average based on last 30 years

Month	*Average (mm)*
January	3.6
February	11.9
March	11.8
April	22.1
May	45.7
June	126.0
July	218.2
August	151.6
September	158.2
October	306.6
November	107.1
December	9.1

Storm Severity

Probability Distribution of Various Severity Storms Per Month

MONTH	*DEPRESSIONS (D) PROBABILITY %*	*CYCLONIC STORMS (CS) PROBABILITY %*	*SEVERE CYCLONIC STORMS (SCS)*	*CS + SCS*	*D + CS + SCS*
January	2		1	1	3
February					
March					
April	1	1		1	2
May	1	3	4	7	8
June	2	2		2	4
July					
August	1	1		1	2
September	22	2	1	3	25
October	21	14	6	20	41
November	10	4	12	16	26
December	3	3		3	6

Notes :

- Probabilities are yearly probabilities of specified storm type occurring in the respective month.
- Analysis is based on 94 years of data.

Environmental Data

Parameter	*Value*	*Data Source*
Water Depth	10 to 15 m	
Wind Speed		MPNG 1992
100 yr (1 min ave @ 10m)	73.9 m/s	
100 yr (3 s gust @ 10m)	88.9 m/s	
100 yr (100 min @ 10m)	23.6 m/s	
Monsoon	16.6 m/s	
Wave Data		
100 yr Hmax	0.75 x SWD *	
Type	Breaking	
100 yr Tmax	13 sec	
1 yr Hmax	7.5m	
1 yr Hs	4.5m	
1 yr Tmax	9.2 sec	
Currents		
Surface max	3.05 m/s	
Seabed max	0.82 m/s	
Marine Growth	125 mm	Assumed
Tide		
Astronomical	1.8m	
Storm Surge	2.5m	
Total Tide	4.3m	
LAT	-0.12m	
Visibility (km at 08:30 hrs)		
1-4	1.4%	
5-10	25.7%	
11-20	70.3%	
>20	2.6%	

* SWD . Still water depth LAT (Lowest Astronomical Tide) + Astronomical Tide + Storm Surge + Water Depth

Ravva Field

Soil Shear Strength versus Depth below Seabed

SOIL DEPTH (m)	*SHEAR STRENGTH (kPa)*
0 to 5	1
5 to 10	7
10 to 20	14
20 to 30	20
30 to 40	27
40 to 50	31
50 to 60	32
60 to 80	33
80 to 100	36
100 to 150	37

Equipment list - onshore facilities

Item	Description	Size	Design kPa	Des degC	Capacity
	Process:				
T-200/21	Oil storage tanks	2x250kb			
P-430	Oil loadout/export pump	250kb/d (360kW)			
	Generator				
	Water treatment skid				
	Utilities				
V-130	Slug receiver				
V-150	Production separator				
V-160	Stabiliser vessel				
	Gas dehydration package				
V-140	Suction scrubber - gas compressor				
C-1500	Gas compressor	710kW			8 Mscf/d
E-500	Aftercooler				
P-410	Water injection pump	250kW	2800	20	50 kb/d
P-420	Groundwater pump				
P-400	Stabilised oil pump				50 kb/d
U-800	Fired heater - hot oil				
E-400	Heat exchanger - crude/crude				
E-410	Heat exchanger - crude/hot oil				
	Piping systems				
	Electrical/instrument items				
	Service water pump				
	Potable water tank				
	Firewater tank				
	Fire pump				
	Hydrants and piping				
	Chemical injection pumps and storage				
	Emergency generator				
	Other:				
	Control/admin building				
	Electrical substation				
	Maintenance building and storage/warehouse				
	Security fence and gatehouse				
	Roads				
	Drainage system				
	Telephone and other communications				

Table 10

Ravva Field Development Drilling

Estimated Drilling & Completion Times for Typical Wells

	Template Well Vertical (Days)	*Platform Well Vertical (Days)*	*Platform Well Deviated 30° (Days)*	*Platform Well Deviated 50° (Days)*
Rig up	1	1	1	1
Drill 24" hole	1	1	1	1
Set 18⅝" casing	½	½	½	½
Install 20" BOP	½	½	½	½
Drill 17½" hole to KOP	-	-	1	1
Drill build-up	-	-	2	3
Drill to 13⅜" casing point	2	2	1	1½
Run 13⅜" casing	1	1	1	1
Install 13⅜" BPP	1	1	1	1
Drill 12¼" hole	2	2	2	2½
Log	1	1	1	1
Run 9⅝" casing	1	1	1	1
Retrieve riser	1	-	-	-
Skid rig	1	-	-	-
Run riser	1	-	-	-
Rig up	1	½	½	½
Clean out	1	1	1	1
Run CBL	½	½	½	½
Perforate	½	½	½	½
Run completion	1	1	1	1½
Install tree	½	½	½	½
Rig down	1	1	1	1
Contingency	2½	2	3	3½
Total	22	18	21	24
Average well duration 22 days.				

Ravva Field Development Drilling

Estimated Average Well Costs

(in US dollars)

i) Daily Charges

	$
Rig	28,000
Two Supply Boats	15,000
Helicopter	5,000
Fixed wing	3,000
Fuel	5,000
Port costs	3,000
Directional drilling services	5,000
Other service rental	4,000
Supervision	2,000
Total cost per day	70,000

ii) Per Well Costs

	$
Drilling mud	100,000
Drilling bits	50,000
Cement	70,000
Electric logging	100,000
Cased hole services	70,000
Casing and completion equipment	500,000
Total	890,000

TOTAL COST OF AVERAGE WELL $2,430,000

Table 12

Ravva Field Development

Phase 1 Capital Costs

(in US dollars, excluding import duty)

1. *CONSTRUCTION*	
Platform Ravva-B	4.30
Topsides	2.91
Pipelines R-B to R-10	1.11
SPM	8 40
Loading Line	8.19
Onshore processing - Phase I	2.35
Derrick Barge Mob/Demob	2.52
Environmental	0.50
Shorebase	1.00
Pre-production Operating Costs	1.00
Insurance	0.65
Project Management	1.50
Contingency (10%)	3.44
Sub-total	37.87
2. *DRILLING*	
Rig mobilisation	0.50
Six wells	14.58
Sub-total	15.08
TOTAL PHASE I	52.45

Ravva Field Development

Phase 2 Capital Costs

(in US dollars, excluding import duty)

1. *CONSTRUCTION*	
Platform R-A	3.92
Topsides	2.91
Platform R-C	3 69
Topsides	2.91
Bridge to R-17	0 24
Platform R-D	3 79
Topsides	2.91
16" WF line	7.32
10" WI line	5.26
4" GL line	3.94
Derrick barge mob/demob	2.52
Onshore processing - Phase II	2.35
Onshore storage	23.20
Water injection facilities	3 50
Environmental	0.50
Insurance	1.38
Project Management	3 00
Contingency (10%)	7.34
Sub-total	80.68
2. DRILLING	
Rig Mobilisation	0.50
12 wells	29.16
Sub-total	29 66
TOTAL PHASE II	110 34

Ravva Field Development

Phase 3 Capital Costs
(in US dollars, excluding import duty)

Gas Lift Facilities	2.20
Insurance	0.04
Project Management	0.50
Contingency (10%)	0.27
TOTAL PHASE III	**3.01**

TOTAL PROJECT COSTS

Construction	105.54
Drilling	44.74
Project Management	5.00
Contingency	11.05
TOTAL	**166.33**

WORLEY ENGINEERING (Australia)

COST BREAKDOWN

Job No. Date
Client Project RAVVA
Subject Tripod Monotower RAVVA A
By Check
File RAVAP1.WK3

Monotower RAVVA-A - 11m water depth
6 slots 5 conductors

ITEM	DESCRIPTION	No.	UNIT	RATE $	$	SUBTOTAL $	COMMENTS
	Monotower substructure						
1	ENGINEERING					150,000	
(a)	Detailed Design	3,000	MANHRS	50	150,000		
2	MATERIAL					1,914,000	
(a)	Jacket weights						
(a)	Framing & legs	160	TONNES	1,200	192,000		
(b)	Connections & nodes	8	TONNES	1,200	9,600		
(c)	Conductor guides & supports	7	TONNES	1,200	8,400		
(d)	Walkways	2	TONNES	1,200	2,400		
(e)	Anodes	12	TONNES	4,000	48,000		
(f)	Boat landing	25	TONNES	1,200	30,000		
(b)	Foundation						
(a)	3 piles 80 [illegible]	330	TONNES	1,200	660,000		
(c)	Conductors						
(a)	5 conductors [illegible]	137	TONNES	1,200	164,400		
3	FABRICATION					1,788,600	
(a)	Jacket						
(a)	Steel	314	TONNES	2,300	722,200		
(b)	Site Supervision	1	ITEM	60,000	60,000		
(b)	Foundation						
(a)	Steel	682	TONNES	1,800	1,226,400		
4	OFFSHORE INSTALLATION					867,125	
(a)	Loadout/Sea fastening						
(a)	Substructure loadout	1	ITEM	80,000	80,000		
(b)	Seafastening material	5	TONNES	1,065	5,325		
(c)	Seafastening fabrication	5	TONNES	3,000	15,000		
(d)	Seafastening	21	DAYS	5,000	105,000		
(e)	Supervision	1	ITEM	4,000	4,000		
(c)	Tugboat [illegible]						
(a)	Mobilisation	1	DAYS	10,000	10,000		
(b)	Use	45	DAYS	10,000	450,000		
(c)	Cargo Barge [illegible]						
(a)	Mob/Demob of Piledriver	1	DAYS	2,000	4,000		Note: Share barge with topsides. Assign 50% of cost to each
(b)	Hire	15	DAYS	7,000	90,000		
(c)	Derrick Barge						
(a)	Mob/Demob from S.E. Asia	0	DAYS	90,000	0		
(b)	Hire	3	DAYS	90,000	270,000		
(c)	Install Conductors	25	DAYS	90,000	225,000		
	TOTAL COST					3,860,825	
5	CONTINGENCY (20%)					772,165	
6	TOTAL COST WITH CONTINGENCY					4,632,990	

Command ® m July 1993

WORLEY ENGINEERING (Australia)

COST BREAKDOWN

Job No. Date 02 Jul 93
Client COMMAND Project RAVVA
Subject 3 legged Monotower RAVVA-B
By A Fern Check R Windas
File RAVP2B WK3

Monotower RAVVA-B - 10m water depth
6 slots 6 conductors

ITEM	DESCRIPTION	No.	UNIT	RATE $	$	SUBTOTAL $	COMMENTS
	Monotower substructure						
1	ENGINEERING					150,000	
(a)	Detailed Design	3,000	MANHRS	50	150,000		
2	MATERIAL					1,147,200	
(i)	Jacket weights						
(a)	Framing & legs	150	TONNES	1,200	182 000		
(b)	Connections & mudmats	8	TONNES	1,200	9 600		
(c)	Conductor guides & supports	7	TONNES	1,200	8,400		
(d)	Walkways	2	TONNES	1,200	2,400		
(e)	Anodes	12	TONNES	4 000	48,000		
(f)	Bon landing	25	TONNES	1,200	30,000		
(ii)	Foundation						
(a)	3 piles 60" dia X 1 1/2" & 2" thk x 110 penetration	550	TONNES	1 200	660,000		
(iii)	Conductors						
(a)	6 conductors 26" dia X 0.5" t	164	TONNES	1 200	196 800		
3	FABRICATION					1 837 400	
(i)	Jacket						
(a)	Steel	214	TONNES	2 300	492 200		
(b)	Site Supervision	1	ITEM	60 000	60 000		
(ii)	Foundation						
(a)	Steel	214	TONNES	1 800	1 285 200		
4	OFFSHORE INSTALLATION					852,375	
(i)	Loadout/Sea fastening						
(a)	Substructure loadout	1	ITEM	60,000	60 000		
(b)	Sealastening material	5	TONNES	1,065	5 325		
(c)	Sealastening fabrication	5	TONNES	3,000	15 000		
(d)	Sealastening	2	DAYS	5 000	10 000		
(e)	Supervision	1	ITEM	4 000	4 000		
(ii)	Tugboat (See note)						
(a)	Mob/Demob	1	DAYS	10 000	10 000		
(b)	Hire	15	DAYS	10 000	150 000		
(iii)	Cargo Barge (See note)						Note Share barge with topsides
(a)	Mob/Demob or Preparation	1	DAYS	2,000	8,000		Assign 50% of costs to each
(b)	Hire	15	DAYS	2,000	30,000		
(iv)	Derrick Barge						
(a)	Mob/Demob from S E Asia	0	DAYS	90,000	0		
(b)	Hire	3	DAYS	90 000	270,000		
(c)	Install Conductors	3	DAYS	90,000	270,000		
	TOTAL COST					3,989,975	
5	CONTINGENCY (20%)					797,245	
6	TOTAL COST WITH CONTINGENCY					4,784,310	

WORLEY

COST BREAKDOWN

Monotower RAVVA-C 15m water depth
6 slots 3 conductors

Job No. Date 02 Jul 93
Client COMMAND Project RAVVA
Subject 3 legged Monotower RAVVA C
By A Mann Check H Mitchell
File RAVP3B.WK1

ITEM	DESCRIPTION	No.	UNIT	RATES	$	SUBTOTAL $	COMMENTS
	Monotower substructure						
1	ENGINEERING					155 500	
1.1	Detailed Design	1,000	MANHRS	30	30,000		
2	MATERIAL					1 113 600	
(a)	Jacket weights						
(i)	Framing & legs	700	TONNES	1 200	210 000		
(ii)	Connectors & mudmats	8	TONNES	1 200	9 600		
(iii)	Conductor guides & supports	8	TONNES	1 200	9 600		
(iv)	Walkways	2	TONNES	1 200	2 400		
(v)	Anodes	15	TONNES	4 000	60 000		
(vi)	Ballasting	25	TONNES	1 200	30 000		
(b)	Foundation						
(i)	3 piles 60 dia [illegible]	550	TONNES	1 200	660 000		
(iii)	Conductors						
(i)	3 conductors 26" dia [illegible]	85	TONNES	1 200	102 000		
3	FABRICATION					1 706 400	
(a)	Jacket						
(i)	Steel	258	TONNES	2 300	593 400		
(ii)	Site Supervision	1	ITEM	60 000	60 000		
(b)	Foundation						
(i)	Steel	525	TONNES	1 800	1 143 000		
4	OFFSHORE INSTALLATION					717,325	
(i)	Landout/Sea fastening						
(i)	Substructure loadout	1	ITEM	80,000	80,000		
(ii)	Seafastening material	5	TONNES	1,065	5 325		
(iii)	Seafastening fabrication	5	TONNES	3,000	15,000		
(iv)	Seafastening	2	DAYS	5,000	10,000		
(v)	Supervision	1	ITEM	4 000	4,000		
(ii)	Tugboat (See note)						
(i)	Mob/Demob	1	DAYS	10 000	10 000		
(ii)	Hire	15	DAYS	10 000	150 000		
(iii)	Cargo Barge (See note)						Note Spare barge with lesser cost. Assign 50% of costs to each.
(i)	Mob/Demob or Preparation	4	DAYS	2 000	8 000		
(ii)	Hire	15	DAYS	2 000	30,000		
(iv)	Derrick Barge						
(i)	Mob/Demob from S E Asia	0	DAYS	80 000	0		
(ii)	Hire	3	DAYS	90 000	270 000		
(iii)	Install Conductors	15	DAYS	90 000	135 000		
	TOTAL COST					3,717,325	
5	CONTINGENCY (20%)					743,465	
6	TOTAL COST WITH CONTINGENCY					4,460,790	

WORLEY ENGINEERING (Australia)

COST BREAKDOWN

Job No Date 01-Jul-93
Client COMMAND Project RAVVA
Subject 3 legged Monotower RAVVA-D
By A Parr Check R Whales
File : RAVVA.wk1

Monotower RAVVA-D - 12m water depth
6 slots 4 conductors

ITEM	DESCRIPTION	No.	UNIT	RATE $	$	SUBTOTAL $	COMMENTS
	Monotower substructure						
1	ENGINEERING					130,000	
(i)	Detailed Design	2,000	MANHRS	50	130,000		
2	MATERIAL					1,062,400	
(i)	Jacket weights						
(a)	Framing & legs	160	TONNES	1,200	192,000		
(b)	Connections & mudmats	8	TONNES	1,200	9,600		
(c)	Conductor guides & supports	7	TONNES	1,200	8,400		
(d)	Walkways	2	TONNES	1,200	2,400		
(e)	Anodes	12	TONNES	4,000	48,000		
(f)	Boat landing	25	TONNES	1,200	30,000		
(ii)	Foundation						
(a)	3 piles - 60° dia X 1 1/2" & 2" wall x 110m penetration	550	TONNES	1,200	660,000		
(iii)	Conductors						
(a)	4 conductors - 26" dia X 0.5" th	110	TONNES	1,200	132,000		
3	FABRICATION					1,740,200	
(i)	Jacket						
(a)	Steel	214	TONNES	2,300	492,200		
(b)	Site Supervision	1	ITEM	60,000	60,000		
(ii)	Foundation						
(a)	Steel	660	TONNES	1,800	1,188,000		
4	OFFSHORE INSTALLATION					782,325	
(i)	Loadout/Sea fastening						
(a)	Substructure loadout	1	ITEM	80,000	80,000		
(b)	Seafastening material	5	TONNES	1,065	5,325		
(c)	Seafastening fabrication	5	TONNES	3,000	15,000		
(d)	Seafastening	2	DAYS	5,000	10,000		
(e)	Supervision	1	ITEM	4,000	4,000		
(ii)	Tugboat (See note)						
(a)	Mob/Demob	1	DAYS	10,000	10,000		
(b)	Hire	15	DAYS	10,000	150,000		
(iii)	Cargo Barge (See note)						Note Share barge and tugboat
(a)	Mob/Demob & Preparation	4	DAYS	2,000	8,000		Assign 50% of costs to each
(b)	Hire	15	DAYS	2,000	30,000		
(iv)	Derrick Barge						
(a)	Mob/Demob from S E Asia	0	DAYS	80,000	0		
(b)	Hire	3	DAYS	90,000	270,000		
(c)	Install Conductors	2	DAYS	90,000	180,000		
	TOTAL COST					3,734,525	
5	CONTINGENCY (20%)					746,905	
6	TOTAL COST WITH CONTINGENCY					4,481,910	

WORLEY ENGINEERING (Australia) COST BREAKDOWN

Monotower topsides

Job no Date 01-Jul-93
Client COMALCO Project Bayer
Subject Monotower topsides
By [illegible] Sheet [illegible]
File HAYDECK.WK3

ITEM	DESCRIPTION	No	UNIT	RATE $	$	SUBTOTAL $	COMMENTS
	Monotower topsides						
1	ENGINEERING					175600	
(a)	Detailed Design	3 500	MANHRS	50	175 000		
2	MATERIAL					743 000	
(a)	Topside weight						
(i)	Helideck	35	TONNES	1 200	42 000		
	Equipment deck level	55	TONNES	1 200	66 000		
(b)	Wellhead level & struts	5	TONNES	1 200	6 000		
(c)	Monotower connection	25	TONNES	1 200	30 000		
3	EQUIPMENT					450 000	
(a)	Process / Facilities 450 tonnes (as per equip't list)	1	ITEM	450 000	450 000		From equipment list
4	FABRICATION					1,030,000	
(a)	Topsides						
(i)	Steel	120	TONNES	3 000	360 000		
(b)	Bulks supply and install	1	TONNES	320 000	320 000		
(c)	Piping & launchers	1	ITEM	300 000	300 000		
(e)	Pre-commission						
(i)	Onshore	1	ITEM	50 000	50 000		
5	OFFSHORE INSTALLATION					743,325	
(a)	Loadout/Sea fastening						
(i)	Modules loadout	1	ITEM	80 000	80 000		
(b)	Sea fastening material	5	TONNES	1 065	5 325		
(c)	Sea fastening fabrication	5	TONNES	3 000	15 000		
(d)	Sea fastening	2	DAYS	5 000	10 000		
(e)	Supervision	1	ITEM	5 000	5 000		
(b)	Tugboat (See note)						
(i)	Mob/Demob	1	DAYS	10 000	10 000		
(b)	Hire	15	DAYS	10 000	150 000		
(iii)	Cargo Barge (See note)						Note Share barge with subsequent
(a)	Mob/Demob or Preparation	4	DAYS	2 000	8,000		Assign 50% of costs to each
(b)	Hire	15	DAYS	2 000	30 000		
(iv)	Derrick Barge						
(b)	Hire	3	DAYS	90 000	270 000		
(v)	Hookup and Commission	1	ITEM	160 000	160 000		
	TOTAL COST					2 342 325	
	CONTINGENCY (20%)					468 465	
	TOTAL COST WITH CONTINGENCY					2 810 790	

PROJECT: RAVVA OILFIELD DEVELOPMENT — F&E.RAVMOB.WK3

MOBILISATION/DEMOBILSATION COSTS: LARGE DIA. PIPELINES

PIPELINE LENGTH		km	0.0		
PIPELINE OUTSIDE DIAMETER		in (nom.)	0	mm	0
PIPELINE WALL THICKNESS		in	0	mm	0.00
CONC COAT THICKNESS		in	3	mm	0
WATER DEPTH		m	0		
PIPELINE MATERIAL	CARBON STEEL		API 5L X65		
	DUPLEX				
	INTERNALLY CLAD				

1 PIPELINE CONSTRUCTION

LAYBARGE OPERATIONS	QUANTITY	days/UNIT	RATE	DURATION (days)
PIPELAY BARGE MOB/DEMOB	1	No	24	24
PIPELAY	0	km	0.38	0
No PIPELINE CROSSINGS	0	No	3	0
No PIPELAY START UP/LAYDOWN	0	No	2	0
No. MIDLINE TIE-INS	0	No	4	0
UNFACTORED LAYBARGE DURATION				24
WAITING ON WEATHER		%	0	0.0
MATERIAL FACTOR				1.0
TOTAL LAYBARGE DURATION				24

2 RISERS & TIE INS

RISER LOCATION	TYPE	NUMBER	LENGTH EACH	TOTAL LENGTH
PLATFORM	FIXED	0	0	0
SUBSEA MANIFOLD	FIXED	0	0	0

3 DIVING SUPPORT VESSEL OPERATIONS

ACTIVITY	QUANTITY	days/UNIT	RATE	DURATION (days)
MOB/DEMOB	0	No	12	0
PLATFORM RISER TIE-IN	0	No	2	0
SUBSEA MANIFOLD TIE-IN	0	No	2	0
POST PIPELAY PIG & TEST	0	No.	1	0
FREESPAN CORRECTION	0	No.	0.25	0
UNFACTORED DSV DURATION				0
WAITING ON WEATHER		%	0	0.0
TOTAL DIVING SUPPORT VESSEL DURATION				0

4 SURVEY VESSEL OPERATIONS

ACTIVITY	QUANTITY	days/UNIT	RATE	DURATION (days)
MOB/DEMOB	1	No.	12	12
PRE-PIPELAY SURVEY	0	km	0.125	0
POST PIPELAY SURVEY	0	km	0.125	0
UNFACTORED SURVEY VESSEL DURATION				12.00
WAITING ON WEATHER		%	10	1.2
TOTAL SURVEY VESSEL DURATION				13

5 PROCUREMENT

	QUANTITY	UNIT	RATE	COST (US$'1000)
LINE PIPE (Delivered to coater)	0	Tonnes	1.2	0.0
ANTI-CORROSION COATING	0	km	10	0.0
CONCRETE COATING	0	km	15	0.0
CATHODIC PROTECTION	0	km	4.5	0.0
PLATFORM RISERS / SPOOL PIPE	0	m	0.38	0.0
PLATFORM RISER / SPOOL FITTINGS	0	No	5	0.0
TRANSPORT OF LINEPIPE (after coating)	0	Tonnes	0.006	0.0
UNFACTORED PROCUREMENT COST TOTAL				0.0
OVERAGE ON STEEL WEIGHT		%	5	0.0
PROCUREMENT COST TOTAL				0.0

6 CONSTRUCTION

	DURATION	RATE	COST (US$'1000)
PIPELAY BARGE	24	114	2736.0
DIVING SUPPORT VESSEL	0	45	0.0
SURVEY VESSEL	13	10	130.0
	No	RATE	COST (US$'1000)
SHORE APPROACHES	0	3000	0.0
CONSTRUCTION COST TOTAL			2866.0

7 COMMISSIONING

	CONSTRUCTION COST TOTAL	RATE %	COST (US$'1000)
	2866.0	0	0.0

8	SUBTOTAL A	US$	2,866,000
9	DESIGN ENGINEERING	MANHOURS: 0	LABOUR RATE: 65	COST (US$'1000): 0.0
10	PROJECT MANAGEMENT	MANHOURS: 0	LABOUR RATE: 95	COST (US$'1000): 0.0
11	INSURANCE & CERTIFICATION	SUBTOTAL A: 2866	RATE %: 2.50	COST (US$'1000): 71.7
12	SUBTOTAL B	US$	71,650
13	PROJECT CONTINGENCY	% RATE: 20	US$	567,530
14	TOTAL COST	US$	3,575,180

PROJECT : RAVVA OILFIELD DEVELOPMENT

70" PIPELINE TO SPM (Including 2.5km on shore)

PIPELINE LENGTH	km	17.5		
PIPELINE OUTSIDE DIAMETER	in (nom.)	20	mm	508
PIPELINE WALL THICKNESS	in	0.5	mm	12.70
CONC COAT THICKNESS	in	2	mm	50
WATER DEPTH	m	430		
PIPELINE MATERIAL	CARBON STEEL	API 5L X65		
	DUPLEX			
	INTERNALLY CLAD			

1 PIPELINE CONSTRUCTION

LAYBARGE OPERATIONS

	QUANTITY	UNIT/UNIT	RATE	DURATION (days)
PIPELAY BARGE MOB/DEMOB	0	no.	18	0
PIPELAY	17.5	km	0.45	8
no PIPELINE CROSSINGS	0	no.	3	0
no PIPELAY START UP/LAYDOWN	1	no.	2	2
no MIDLINE TIE INS	0	no.	4	0
UNFACTORED LAYBARGE DURATION				10
WAITING ON WEATHER		%	10	1.0
MATERIAL FACTOR				1.0
TOTAL LAYBARGE DURATION				11

2 RISERS & TIE - INS

RISER LOCATION	TYPE	NUMBER	LENGTH EACH	TOTAL LENGTH
PLATFORM	FIXED	8	0	0
SUBSEA MANIFOLD	FIXED	0	0	0

3 DIVING SUPPORT VESSEL OPERATIONS

ACTIVITY

	QUANTITY	UNIT/UNIT	RATE	DURATION (days)
MOB/DEMOB	0	no.	8	0
PLATFORM RISER TIE IN	0	no.	2	0
SUBSEA MANIFOLD TIE IN	0	no.	2	0
POST PIPELAY PIG & TEST	0	no.	1	0
FREESPAN CORRECTION	0	no.	0.25	0
UNFACTORED DSV DURATION				0
WAITING ON WEATHER		%	10	0.0
TOTAL DIVING SUPPORT VESSEL DURATION				0

4 SURVEY VESSEL OPERATIONS

ACTIVITY

	QUANTITY	UNIT/UNIT	RATE	DURATION (days)
MOB/DEMOB	0	no.	4	0
PRE-PIPELAY SURVEY	17.5	km	0.125	2.1875
POST PIPELAY SURVEY	17.5	km	0.125	2.1875
UNFACTORED SURVEY VESSEL DURATION				4.40
WAITING ON WEATHER		%	10	0.4
TOTAL SURVEY VESSEL DURATION				5

5 PROCUREMENT

	QUANTITY	UNIT	RATE	COST (US$'1000)
LINE PIPE (Delivered to Ravva)	2718	Tonnes	1.3	3261.6
ANTI-CORROSION COATING	17.5	km	10	170.7
CONCRETE COATING	17.5	km	15	262.5
CATHODIC PROTECTION	17.5	km	4.5	78.8
PLATFORM RISERS / SPOOL PIPE	0	no.	0.38	0.0
PLATFORM RISER / SPOOL FITTINGS	0	no.	5	0.0
TRANSPORT OF LINEPIPE (inter country)	6580	Tonnes	0.035	230.8
UNFACTORED PROCUREMENT COST TOTAL				4007.3
OVERAGE ON STEEL WEIGHT		%	3	97.9
PROCUREMENT COST TOTAL				4107.2

6 CONSTRUCTION

	DURATION	RATE	COST (US$'1000)
PIPELAY BARGE	11	114	1254.0
DIVING SUPPORT VESSEL	0	43	0.0
SURVEY VESSEL	5	10	50.0
	NO	RATE	COST (US$'1000)
SHORE APPROACHES	1	1000	1000.0
ONSHORE TIE-IN/CHING	1	250	250.0
CONSTRUCTION COST TOTAL			2554.0

7 COMMISSIONING

CONSTRUCTION COST TOTAL	RATE %	COST (US$'1000)
2554.0	1	25.5

8 SUBTOTAL A — US$ 6,881,997

9 DESIGN ENGINEERING

MANHOURS	LABOUR RATE	COST (US$'1000)
2981	65	193.8

10 PROJECT MANAGEMENT

MANHOURS	LABOUR RATE	COST (US$'1000)
1968	95	187.1

11 INSURANCE & CERTIFICATION

SUBTOTAL A	RATE %	COST (US$'1000)
6882	2.50	167.0

12 SUBTOTAL B — US$ 361,899

13 PROJECT CONTINGENCY — % RATE 20 — US$ 1,448,918

14 TOTAL COST — US$ 8,692,510

Table 22

PROJECT : RAVVA OILFIELD DEVELOPMENT — FILE:RAVVA16.WK1

16" PIPELINE from RAVVA-D via RAVVA-A OFFSHORE PLATFORMS (Including 2.5km onshore)

PIPELINE LENGTH		km	14.0		
PIPELINE OUTSIDE DIAMETER		in (nom.)	16	mm	406.4
PIPELINE WALL THICKNESS		in	0.5	mm	12.7
CONC.COAT THICKNESS		in	2	mm	50
WATER DEPTH		m	10		
PIPELINE MATERIAL	CARBON STEEL		API 5L X65		
	DUPLEX				
	INTERNALLY CLAD				

1 PIPELINE CONSTRUCTION

LAYBARGE OPERATIONS	QUANTITY	days/UNIT	RATE	DURATION(days)
PIPELAY BARGE MOB/DEMOB	0	No.	10	0
PIPELAY	14	km	0.43	6
No PIPELINE CROSSINGS	0	No	3	0
No PIPELAY START UP/LAYDOWN	1	No.	2	2
No MIDLINE TIE-INS	1	No.	4	4
UNFACTORED LAYBARGE DURATION				12
WAITING ON WEATHER		%	10	1.2
MATERIAL FACTOR				0
TOTAL LAYBARGE DURATION				13

2 RISERS & TIE - INS

RISER LOCATION	TYPE	NUMBER	LENGTH EACH	TOTAL LENGTH
PLATFORM	FIXED	2	20	40
SUBSEA MANIFOLD	FIXED	0	0	0

3 DIVING SUPPORT VESSEL OPERATIONS

ACTIVITY	QUANTITY	days/UNIT	RATE	DURATION(days)
MOB/DEMOB	0	No.	8	0
PLATFORM RISER TIE-IN	0	No.	2	0
SUBSEA MANIFOLD TIE-IN	0	No	2	0
POST PIPELAY PIG & TEST	0	No	1	0
FREESPAN CORRECTION	0	No	0.25	0
UNFACTORED DSV DURATION				0
WAITING ON WEATHER		%	10	0
TOTAL DIVING SUPPORT VESSEL DURATION				0

4 SURVEY VESSEL OPERATIONS

ACTIVITY	QUANTITY	days/UNIT	RATE	DURATION(days)
MOB/DEMOB	0	No.	4	0
PRE-PIPELAY SURVEY	14	km	0.125	1.75
POST PIPELAY SURVEY	14	km	0.125	1.75
UNFACTORED SURVEY VESSEL DURATION				3.50
WAITING ON WEATHER		%	10	0.4
TOTAL SURVEY VESSEL DURATION				4

5 PROCUREMENT

	QUANTITY	UNIT	RATE	COST (US$'1000)
LINE PIPE(Delivered to dock)	1729	Tonnes	1.2	2074.8
ANTI-CORROSION COATING	14	km	10	136.6
CONCRETE COATING	14	km	15	210.0
CATHODIC PROTECTION	14	km	4.5	63.0
PLATFORM RISERS / SPOOL PIPE	40	m	0.39	15.6
PLATFORM RISER / SPOOL FITTINGS	0	No	5	0.0
TRANSPORT OF LINEPIPE (dock coating)	4270	Tonnes	0.035	149.5
UNFACTORED PROCUREMENT COST TOTAL				2649.5
OVERAGE ON STEEL WEIGHT		%	3	62.7
PROCUREMENT COST TOTAL				2712.2

6 CONSTRUCTION

	DURATION	RATE	COST (US$'1000)
PIPELAY BARGE	13	114	1482.0
DIVING SUPPORT VESSEL	0	45	0.0
SURVEY VESSEL	4	10	40.0
	No	RATE	COST (US$'1000)
SHORE APPROACHES	1	1000	1000.0
ONSHORE TRENCHING	1	250	250.0
CONSTRUCTION COST TOTAL			2772.0

7 COMMISSIONING

CONSTRUCTION COST TOTAL	RATE %	COST (US$'1000)
2772.0	11	277.1

8 SUBTOTAL A — US$ 5,511,882

9 DESIGN ENGINEERING

MANHOURS	LABOUR RATE	COST (US$'1000)
3459	85	294.0

10 PROJECT MANAGEMENT

MANHOURS	LABOUR RATE	COST (US$'1000)
1625	85	134.3

11 INSURANCE & CERTIFICATION

SUBTOTAL A	RATE %	COST (US$'1000)
5512	2.50	137.8

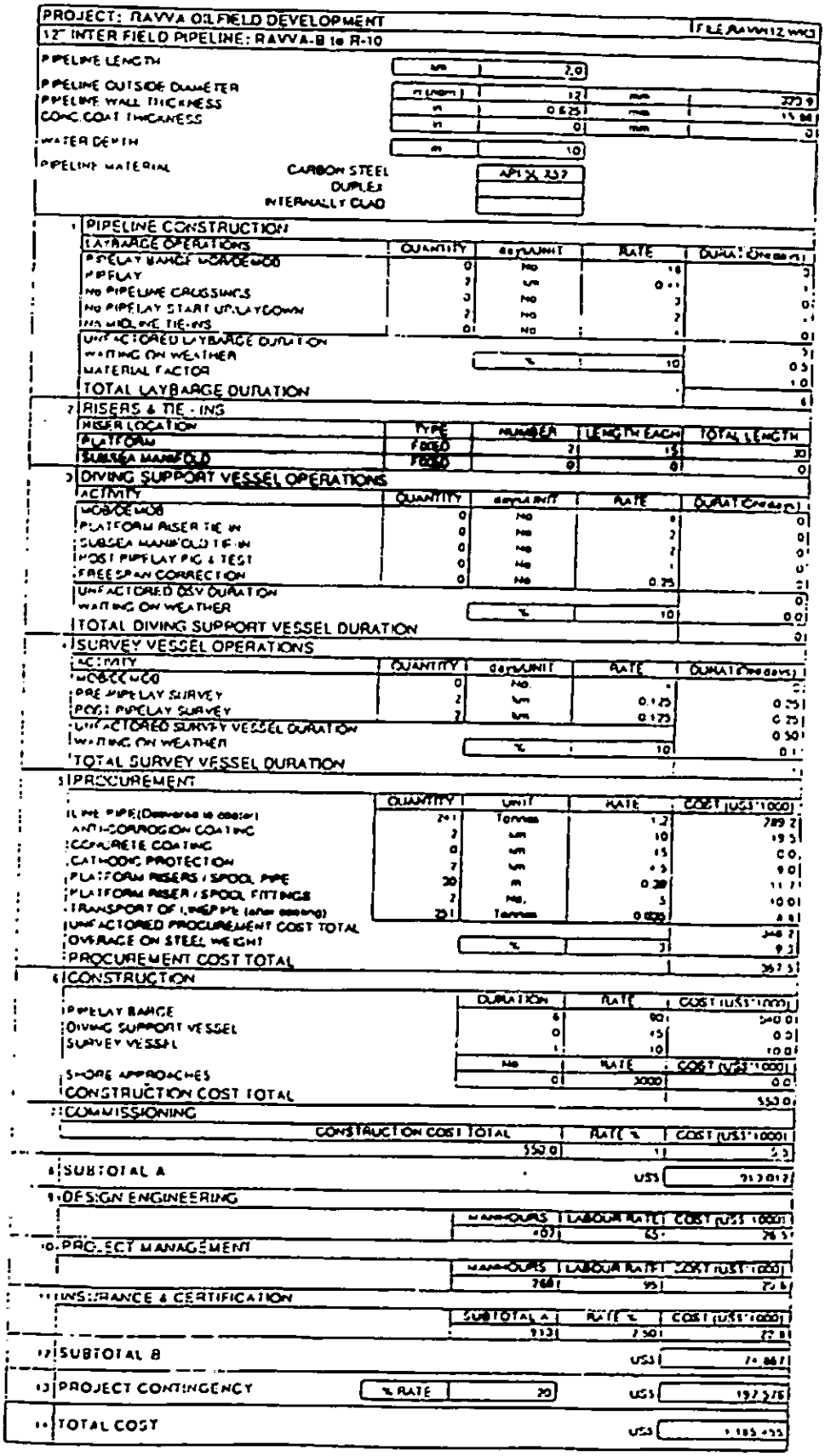
12 SUBTOTAL B — US$ 631,974

13 PROJECT CONTINGENCY — % RATE 20 — US$ 1,192,771

14 TOTAL COST — US$ 7,158,628

Command Petroleum, July 1993
WG&P

Table 23



PROJECT: RAVVA OILFIELD DEVELOPMENT

12" INTER FIELD PIPELINE: RAVVA-B to R-10

PIPELINE LENGTH	km	7.0		
PIPELINE OUTSIDE DIAMETER	inches	12	mm	323.9
PIPELINE WALL THICKNESS	mm	0.625	mm	15.88
CONC. COAT THICKNESS	mm	0	mm	0
WATER DEPTH	m	10		
PIPELINE MATERIAL	CARBON STEEL	API X 52?		
	DUPLEX			
	INTERNALLY CLAD			

1 PIPELINE CONSTRUCTION

LAYBARGE OPERATIONS

	QUANTITY	days/UNIT	RATE	DURATION (Days)
PIPELAY BARGE MOBE/DEMOB	0	30	1.0	3
PIPELAY	7	0.5	0.5	3
No PIPELINE CROSSINGS	3	0.5	1	0
No PIPELAY START UP/LAYDOWN	2	0.5	2	1
No MID LINE TIE-INS	0	0.5	1	0
UNFACTORED LAYBARGE DURATION				3
WAITING ON WEATHER		%	10	0.3
MATERIAL FACTOR				1.0
TOTAL LAYBARGE DURATION				4

2 RISERS & TIE - INS

RISER LOCATION	TYPE	NUMBER	LENGTH EACH	TOTAL LENGTH
PLATFORM	FIXED	2	15	30
SUBSEA MANIFOLD	FIXED	0	0	0

3 DIVING SUPPORT VESSEL OPERATIONS

ACTIVITY	QUANTITY	days/UNIT	RATE	DURATION (Days)
MOBE/DEMOB	0	20	1	0
PLATFORM RISER TIE IN	0	2	2	0
SUBSEA MANIFOLD TIE IN	0	2	2	0
POST PIPELAY PIG & TEST	0	1	1	0
FREESPAN CORRECTION	0	10	0.25	2
UNFACTORED DSV DURATION				0
WAITING ON WEATHER		%	10	0.0
TOTAL DIVING SUPPORT VESSEL DURATION				0

4 SURVEY VESSEL OPERATIONS

ACTIVITY	QUANTITY	days/UNIT	RATE	DURATION (Days)
MOBE/DEMOB	0	20	1	2
PRE PIPELAY SURVEY	2	0.5	0.125	0.25
POST PIPELAY SURVEY	2	0.5	0.125	0.25
UNFACTORED SURVEY VESSEL DURATION				0.50
WAITING ON WEATHER		%	10	0.1
TOTAL SURVEY VESSEL DURATION				1

5 PROCUREMENT

	QUANTITY	Unit	RATE	COST (US$'1000)
LINE PIPE (Delivered to dock)	241	Tonnes	1.2	289.2
ANTI-CORROSION COATING	2	km	10	19.5
CONCRETE COATING	0	km	15	0.0
CATHODIC PROTECTION	7	km	1.5	9.0
PLATFORM RISERS / SPOOL PIPE	30	Te.	0.38	11.71
PLATFORM RISER / SPOOL FITTINGS	2	Te.	5	10.01
TRANSPORT OF LINEPIPE (after coating)	241	Tonnes	0.020	4.81
UNFACTORED PROCUREMENT COST TOTAL				344.2
OVERAGE ON STEEL WEIGHT		%	3	9.3
PROCUREMENT COST TOTAL				353.5

6 CONSTRUCTION

	DURATION	RATE	COST (US$'1000)
PIPELAY BARGE	6	80	240.01
DIVING SUPPORT VESSEL	0	45	0.0
SURVEY VESSEL	1	10	10.0
	No	RATE	COST (US$'1000)
SHORE APPROACHES	0	3000	0.0
CONSTRUCTION COST TOTAL			550.0

7 COMMISSIONING

CONSTRUCTION COST TOTAL	RATE %	COST (US$'1000)
550.0	1	5.5

8 SUBTOTAL A — US$ 913.017

9 DESIGN ENGINEERING

MANHOURS	LABOUR RATE	COST (US$'1000)
407	65	26.5

10 PROJECT MANAGEMENT

MANHOURS	LABOUR RATE	COST (US$'1000)
2681	95	25.5

11 INSURANCE & CERTIFICATION

SUBTOTAL A	RATE %	COST (US$'1000)
913	2.50	22.8

12 SUBTOTAL B — US$ 1.088

13 PROJECT CONTINGENCY — % RATE 20 — US$ 197.575

14 TOTAL COST — US$ 1.185.435

Command Petroleum, July 1993
WG&P

Table 24

PROJECT: HAVVA OILFIELD DEVELOPMENT — FILE:HAVW10.WK3

10" WATER INJECTION PIPELINE (20 km to platforms HAVVA-A, B, C & D & 2.5 km Swamp)

PIPELINE LENGTH		km	22.5		
PIPELINE OUTSIDE DIAMETER		in (nom)	10	mm	273.1
PIPELINE WALL THICKNESS		in	0.365	mm	9.27
CONC.COAT THICKNESS		"	0	mm	0
WATER DEPTH		m	15		
PIPELINE MATERIAL	CARBON STEEL		API 5L X52		
	DUPLEX				
	INTERNALLY CLAD				

1 PIPELINE CONSTRUCTION

LAYBARGE OPERATIONS

	QUANTITY	days/UNIT	RATE	DURATION(days)
PIPELAY BARGE MOB/DEMOB	0	No	18	0
PIPELAY	22.5	km	0.20	5
No.PIPELINE CROSSINGS	0	No	3	0
No PIPELAY START UP/LAYDOWN	2	No	1	2
No MIDLINE TIE-INS	2	No	2	4
UNFACTORED LAYBARGE DURATION				11
WAITING ON WEATHER		%	10	1.1
MATERIAL FACTOR				1.0
TOTAL LAYBARGE DURATION				12

2 RISERS & TIE - INS

RISER LOCATION	TYPE	NUMBER	LENGTH EACH	TOTAL LENGTH
PLATFORM	FIXED	4	15	60
SUBSEA MANIFOLD	FIXED	0	0	0

3 DIVING SUPPORT VESSEL OPERATIONS

ACTIVITY	QUANTITY	days/UNIT	RATE	DURATION(days)
MOB/DEMOB	0	No	8	0
PLATFORM RISER TIE-IN	0	No	2	0
SUBSEA MANIFOLD TIE-IN	0	No	2	0
POST PIPELAY PIG & TEST	0	km	1	0
FREESPAN CORRECTION	0	No	0.25	0
UNFACTORED DSV DURATION				0
WAITING ON WEATHER		%	10	0.0
TOTAL DIVING SUPPORT VESSEL DURATION				0

4 SURVEY VESSEL OPERATIONS

ACTIVITY	QUANTITY	days/UNIT	RATE	DURATION(days)
MOB/DEMOB	0	No	4	0
PRE-PIPELAY SURVEY	22.5	km	0.125	2.8125
POST PIPELAY SURVEY	22.5	km	0.125	2.8125
UNFACTORED SURVEY VESSEL DURATION				5.60
WAITING ON WEATHER		%	10	0.6
TOTAL SURVEY VESSEL DURATION				6

5 PROCUREMENT

	QUANTITY	UNIT	RATE	COST (US$'1000)
LINE PIPE(Delivered to assembly)	1358	Tonnes	1.2	1630.8
ANTI-CORROSION COATING	22.5	km	10	219.5
CONCRETE COATING	0	km	15	0.0
CATHODIC PROTECTION	22.5	km	4.5	101.3
PLATFORM RISERS / SPOOL PIPE	60	m	0.38	22.4
PLATFORM RISER / SPOOL FITTINGS	2	No	5	10.0
TRANSPORT OF LINEPIPE (after coating)	1457	Tonnes	0.035	51.0
UNFACTORED PROCUREMENT COST TOTAL				2035.9
OVERAGE ON STEEL WEIGHT		%	5	+99
PROCUREMENT COST TOTAL				2085.9

6 CONSTRUCTION

	DURATION	RATE	COST (US$'1000)
PIPELAY BARGE	12	90	1080.0
DIVING SUPPORT VESSEL	0	45	0.0
SURVEY VESSEL	6	10	60.0
	No	RATE	COST (US$'1000)
SHORE APPROACHES	1	750	750.0
ONSHORE TRENCHING	1	150	150.0
CONSTRUCTION COST TOTAL			2040.0

7 COMMISSIONING

CONSTRUCTION COST TOTAL	RATE %	COST (US$'1000)
2040.0	1	20.4

8 SUBTOTAL A — US$ 4,146,271

9 DESIGN ENGINEERING

MANHOURS	LABOUR RATE	COST (US$'1000)
1850	85	170.7

10 PROJECT MANAGEMENT

MANHOURS	LABOUR RATE	COST (US$'1000)
1272	85	116.1

11 INSURANCE & CERTIFICATION

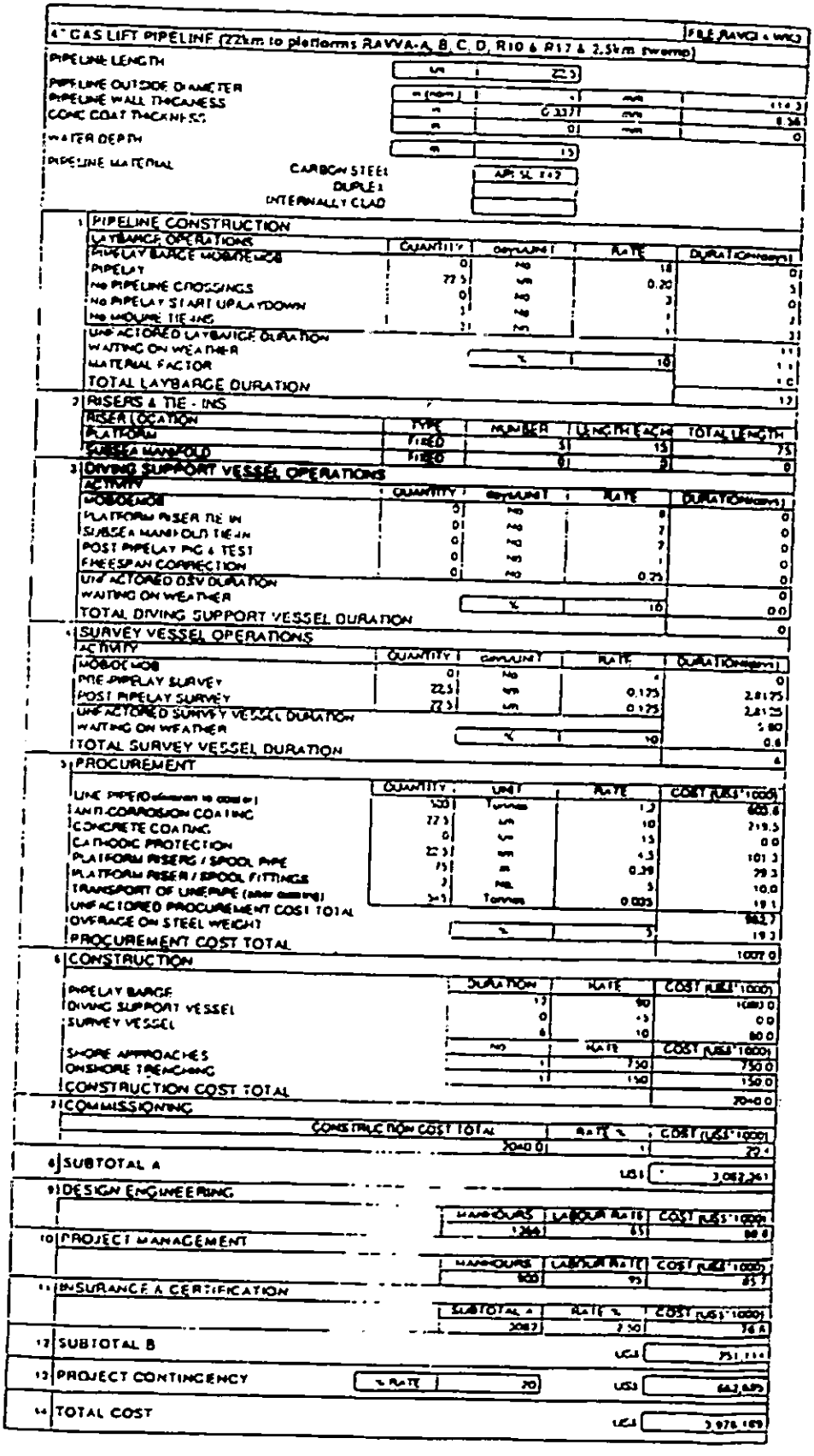
SUBTOTAL A	RATE %	COST (US$'1000)
4146	2.50	103.7

12 SUBTOTAL B — US$ 339,994

13 PROJECT CONTINGENCY — % RATE 20 — US$ 887,253

14 TOTAL COST — US$ 5,383,518

Table 25



4" GAS LIFT PIPELINE (22km to platforms RAVVA-A, B, C, D, R10 & R17 & 2.5km swamp)

PIPELINE LENGTH		22.5		
PIPELINE OUTSIDE DIAMETER			mm	114.3
PIPELINE WALL THICKNESS		6.33	mm	8.56
CONC COAT THICKNESS		0	mm	0
WATER DEPTH		13		
PIPELINE MATERIAL	CARBON STEEL	API 5L X42		
	DUPLEX			
	INTERNALLY CLAD			

1 PIPELINE CONSTRUCTION

LAYBARGE OPERATIONS	QUANTITY	UNIT	RATE	DURATION (days)
PIPELAY BARGE MOBE/DEMOB	0		18	0
PIPELAY	22.5		0.20	5
No PIPELINE CROSSINGS	0		3	0
No PIPELAY START UP & TAKEDOWN	3		1	3
No MOORING TIE-INS	21		1	21
UNFACTORED LAYBARGE DURATION				31
WAITING ON WEATHER		%	10	11
MATERIAL FACTOR				1.1
TOTAL LAYBARGE DURATION				12

2 RISERS & TIE-INS

RISER LOCATION	TYPE	NUMBER	LENGTH EACH	TOTAL LENGTH
PLATFORM	FIXED	3	15	75
SUBSEA MANIFOLD	FIXED	0	0	0

3 DIVING SUPPORT VESSEL OPERATIONS

ACTIVITY	QUANTITY	UNIT	RATE	DURATION (days)
MOBE/DEMOB	0		8	0
PLATFORM RISER TIE IN	0		7	0
SUBSEA MANIFOLD TIE IN	0		7	0
POST PIPELAY PIG & TEST	0		7	0
FREESPAN CORRECTION	0		1	0
UNFACTORED DSV DURATION	0		0.75	0
WAITING ON WEATHER		%	10	0
TOTAL DIVING SUPPORT VESSEL DURATION				0.0

4 SURVEY VESSEL OPERATIONS

ACTIVITY	QUANTITY	UNIT	RATE	DURATION (days)
MOBOC MOB	0		4	0
PRE-PIPELAY SURVEY	22.5		0.125	2.8125
POST PIPELAY SURVEY	22.5		0.125	2.8125
UNFACTORED SURVEY VESSEL DURATION				5.63
WAITING ON WEATHER		%	10	0.6
TOTAL SURVEY VESSEL DURATION				6

5 PROCUREMENT

	QUANTITY	UNIT	RATE	COST (US$'1000)
LINE PIPE (allowance for cutting)	520	Tonnes	1.3	676.0
ANTI-CORROSION COATING	22.5	km	10	219.5
CONCRETE COATING	0	km	15	0.0
CATHODIC PROTECTION	22.5	km	4.5	101.3
PLATFORM RISERS / SPOOL PIPE	75	m	0.38	28.5
PLATFORM RISER / SPOOL FITTINGS	3	No	3	10.0
TRANSPORT OF LINEPIPE (allow cutting)	541	Tonnes	0.035	19.1
UNFACTORED PROCUREMENT COST TOTAL				963.7
OVERAGE ON STEEL WEIGHT		%	5	19.3
PROCUREMENT COST TOTAL				1007.0

6 CONSTRUCTION

	DURATION	RATE	COST (US$'1000)
PIPELAY BARGE	12	90	1080.0
DIVING SUPPORT VESSEL	0	15	0.0
SURVEY VESSEL	6	10	60.0
	NO	RATE	COST (US$'1000)
SHORE APPROACHES	1	750	750.0
ONSHORE TRENCHING	1	150	150.0
CONSTRUCTION COST TOTAL			2040.0

7 COMMISSIONING

CONSTRUCTION COST TOTAL	RATE %	COST (US$'1000)
2040.0	1	22.4

8 SUBTOTAL A	US$	3,082,261

9 DESIGN ENGINEERING

MANHOURS	LABOUR RATE	COST (US$'1000)
1266	65	80.8

10 PROJECT MANAGEMENT

MANHOURS	LABOUR RATE	COST (US$'1000)
900	95	85.7

11 INSURANCE & CERTIFICATION

SUBTOTAL A	RATE %	COST (US$'1000)
2082	2.50	76.8

12 SUBTOTAL B	US$	751,114
13 PROJECT CONTINGENCY % RATE 20	US$	663,895
14 TOTAL COST	US$	3,976,189

WORLEY ENGINEERING (Australia)
COMMAND PETROLEUM HOLDINGS NL

RAVVA STUDY: PIPELINE COST SUMMARY TABLE

BY A PERRI
CHK. R WHILLAS
DATE. 02/07/93

No	DESCRIPTION	DIAMETER inches	WALL mm	COATING mm	LENGTH km	MATERIAL API-5L	COST US $MILL (1)
	PIPELINES from PLATFORMs R-A, D (including 2.5km in swamp)						
(a)	16" including 4km in-field and midline tie-in	16	12.7	50.8	14.0	X65	7.16
	GAS LIFT PIPELINES						
(b)	4" diameter 22km to all platforms and 2.5km swamp	4.5	8.56	0	24.5	X42	4.0
	IN-FIELD PIPELINE						
(c)	12" diameter R-B to R10	12.75	15.88	0	2.0	X52	1.19
	EXPORT PIPELINE TO SPM (including 2.5km in swamp)						
(d)	20" to SPM	20	12.7	50.8	17.5	X65	8.68
(e)	10" WATER INJECTION to platforms RAVVA-A,B,C,D & R17	10.75	9.27	0	22.5	X52	5.38

(1) All costs exclude laybarge spread mob/demob costs

TABLE 6.1

Rev 1

213002CTR WK3

RAVVA FIELD DEVELOPMENT COSTS

A1 SPM COSTS	MILLION
8 point mooring buoy 3" anchor chains 45,000 LW2 anchors SPM (new) Minouli hoses (new) Secondhand cost of above including reconditioning & certification	USD5 million
TRANSPORTATION	USD0.5 million
ENGINEERING $65/hr x 3,000 hours	USD0.2 million
INSTALLATION 7 days @ 90,000 USD/day including anchors and tie-in to SPM	USD0.7 million
SUB TOTAL	USD6.4 million
INSURANCE 2.5% PROJECT MANAGEMENT 6%	USD0.2 million USD0.4 million
SUB TOTAL	USD7.0 million
20% CONTINGENCY	USD1.4 million
TOTAL	USD8.4 million

A2 TANK FARM	MILLION
2 x 250,000 bbl tanks	4.9
Pumps and pipework	3.8
Fire fighting	1.7
Drainage and run-off water treatment	1.2
Foundations bunds, roads	2.0
Buildings	1.3
Instrumentation/utilities	1.8
SUB TOTAL	16.7
PROJECT MANAGEMENT 6%	1.0
SUB TOTAL	17.7
CONTINGENCY 20%	3.5
TOTAL	21.2 million (1)

Note. (1) These costs do not include any provision for land acquisition

Proposed Ravva Field Development
Cash Requirement Schedule (Phases I and II only)
(Million US$)

ear Quarter	1993		1994				1995				1996			
	3	4	1	2	3	4	1	2	3	4	1	2	3	4
ILESTONES	Contract Award 30/9/93			Start export through SPM @ 8,000 bopd		Production increase to 20,000 bopd		Production increase to 50,000 bopd						
PERATING COSTS ncluding shuttle tanker costs)		1 00	1.00	1.50	2.88	2 88	2.88	2.88	2 98	2.98	2 98	2 98	2.98	2.98
ppraisal (excluding drilling)		0.13	0.12											
APITAL COSTS														
roject Management		0.31	0 62	0.62	0.62	0.62	0.62	0 62	0.62	0 62	0.31			
rilling				7.10	3.30	4.95	9 90	9.90	9.59					
arge Mob/Demob				3.88				3.88						
latforms Ravva-B		0.15	0 18	8.28										
Ravva-A				0.33				8.12						
Ravva-C				0.33				8.27						
Ravva-D				0.33				7.95						
anker Loading Facilities		0.40		18.39										
pelines		0.03		1.28		1.16		17.03						
nshore Processing		0.15		2.44				2.58						
torage		0.25			6.60			16.47						
ater Injection Facilities					0.10			3 75						
as Lift Facilities														
nvironmental		0.55					0.55							
hore Base			0.55	0 55										
surance			0.77				1.55							
TOTAL CAPEX	0 00	1 84	2.12	43 53	10 62	6.73	12 62	78.57	10.21	0.62	0 31	0 00	0 00	0.00
CUMULATIVE		1 84	3.96	47 49	58 11	64.84	77 46	156 03	166.24	166 86	167 17	167 17	167.17	167.17

RAVVA FIELD DEVELOPMENT

OPERATING COSTS

		US$
i)	Personnel Includes all Madras and site based personnel and training.	1,600,000
ii)	Administration Includes office rental, communications and Joint Venture and Government liaison	1,000,000
iii)	Service Vessel Includes hire of vessel and crew, and fuel at $3,500 per day	1,300,000
iv)	Helicopter Assumes a twin-engine aircraft with on pilot and mechanic on permanent hire. Allows for 10 hours flying per week.	1,500,000
v)	Repair and Maintenance Includes well servicing.	2,000,000
vi)	Consumables Includes chemicals.	1,000,000
vii)	Insurance Includes well control and pollution insurance.	1,000,000
viii)	Reservoir Management Includes well surveys (10 wells @ $50,000 each) plus reservoir simulation @ $100,000.	600,000
ix)	Environmental Protection Includes conduct of monitoring surveys and maintenance of oil spill booms and equipment.	100,000
x)	Inspections Allows for annual underwater inspection of platforms and pipelines	100,000
xi)	Overheads 6% of annual operating costs.	600,000
xii)	Contingency (10%)	1,100,000
		$11,900,000

Notes :

1 Workover costs are estimated to average $2 million per year commencing the year after establishment of maximum production rates. This estimate is based on working over three wells every two years and includes $0.5 million for mobilisation of a rig each time.

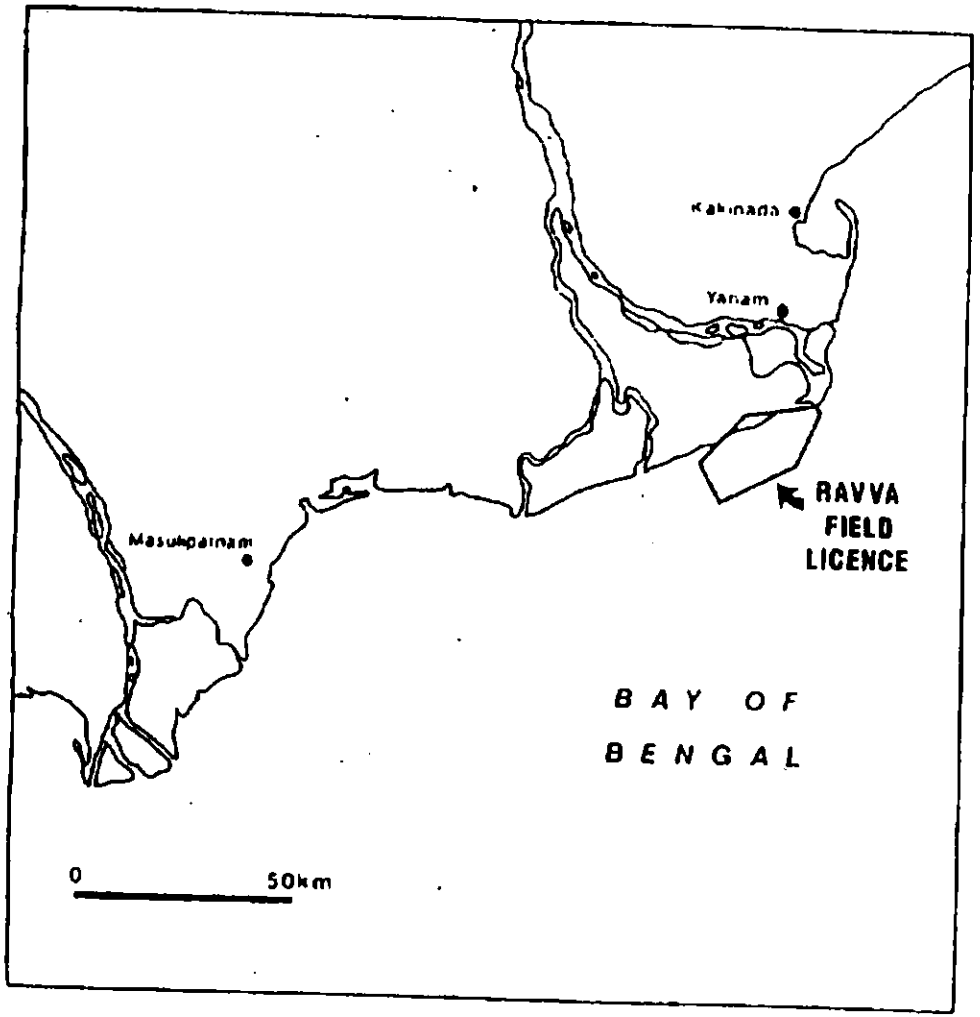
2. During the 12 months following the installation of the tanker loading facilities and before the commissioning of the onshore storage, shuttle tankers will be used to store/transport the oil. During this time operating costs will increase by approximately $15,000 per day. However, during this time other operating costs are estimated to be only 50% of the cost detailed above. This is a result of sharing costs (office rental, helicopter, etc.) with the construction activity, and the fact that less than half the facilities will have been installed. Operating costs during the first 12 months of production will then be :-

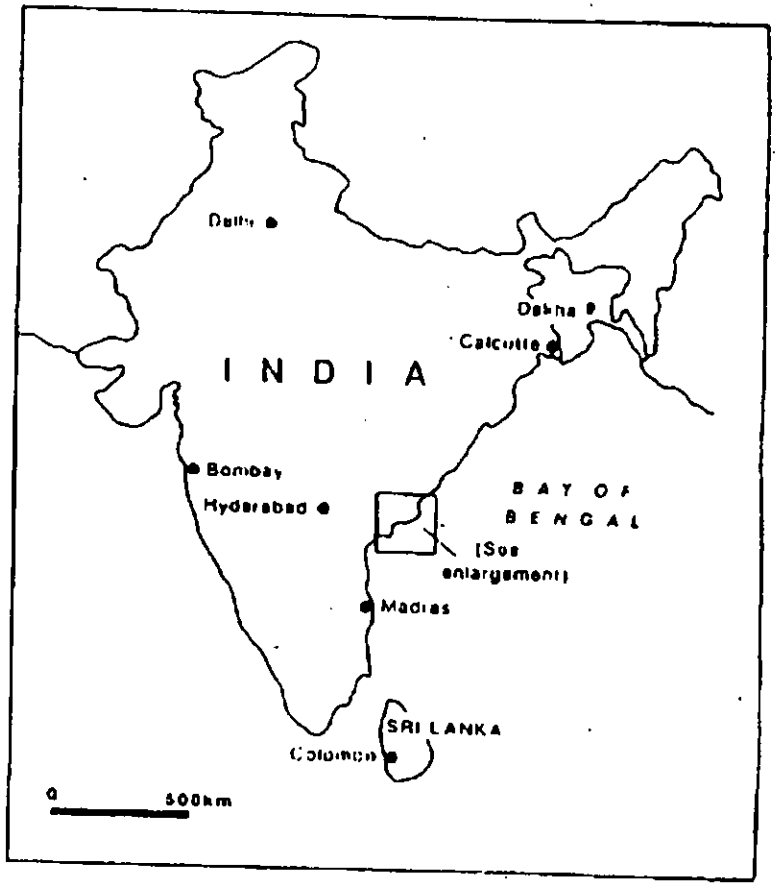
Operating Costs	6,000,000
Shuttle Tankers	5,500,000
Total	$11,500,000

Ravva Field Development

Estimate of Field Abandonment Costs
(in millions of 1993 US dollars)

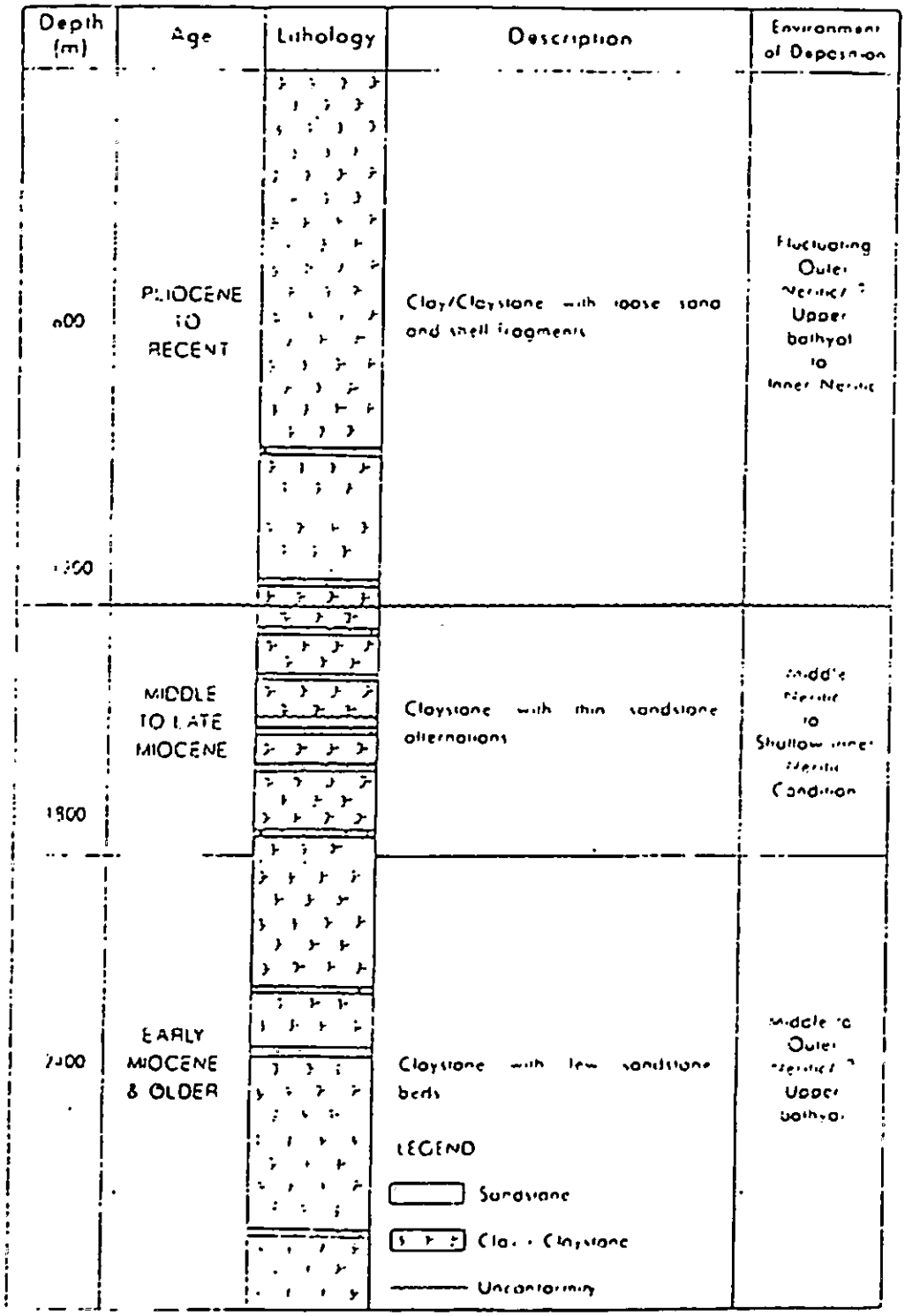
1.	Wells		
	- Mobilisation of rig	0.50	
	- 18 wells x 5 days each x $75,000/day	6.75	
	Total for wells		7.25
2.	Platforms		
	- Mobilisation of barge	2.52	
	- 6 platforms x 5 days each x $100,000/day	3.00	
	total for platforms		5.52
3.	SPM		
	- 2 days x $100,000/day	0.20	
	Total for SPM		0.20
4	Onshore Processing and Storage		
	- Estimate based on experience in Australia	5.0	
	Total		5.0
	TOTAL ESTIMATED ABANDONMENT COSTS		17.97





Command

Figure 1
RAVVA FIELD
LOCATION MAP



Command

Figure 4

RAVVA FIELD

GENERALISED LITHOSTRATIGRAPHY

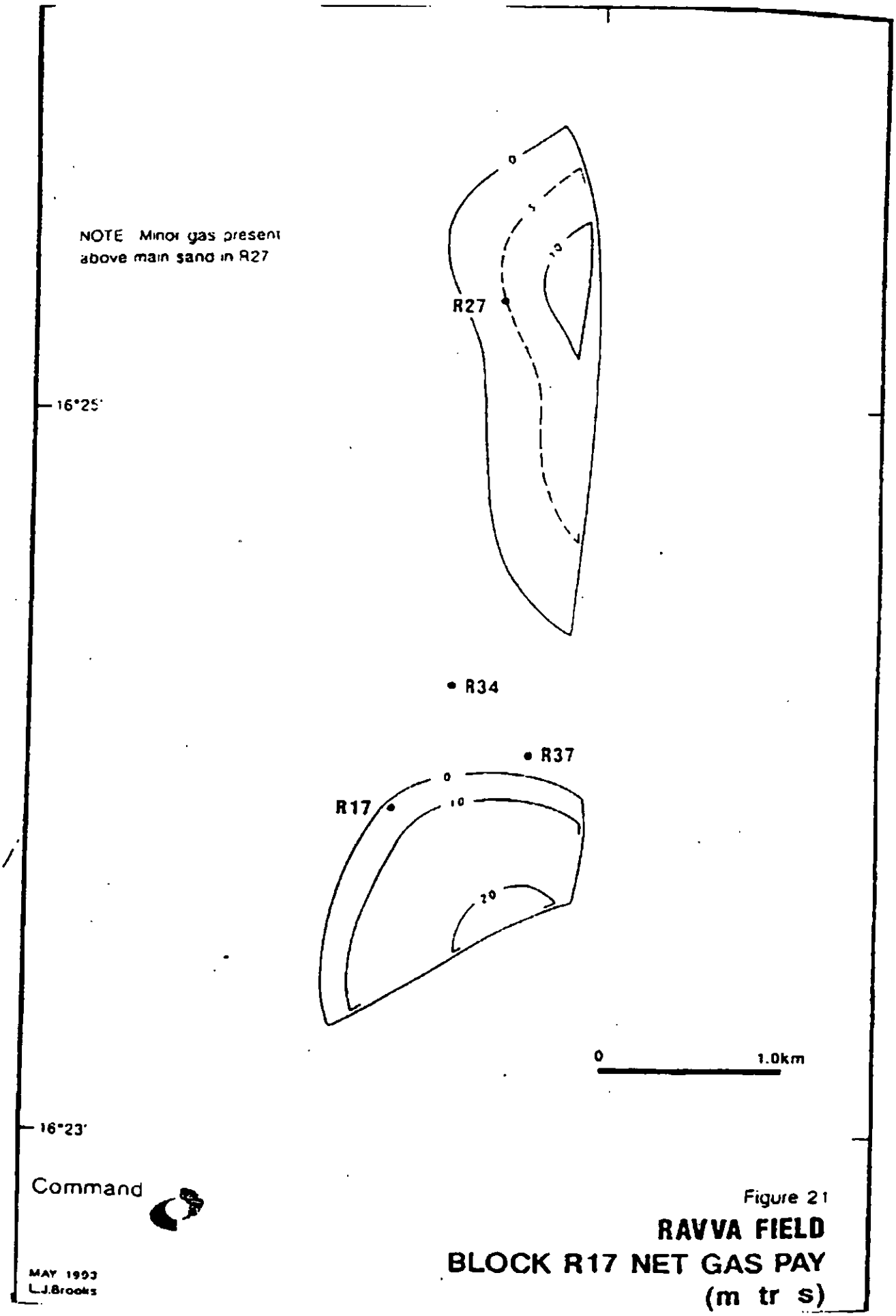


Figure 21

RAVVA FIELD

BLOCK R17 NET GAS PAY

(m tr s)

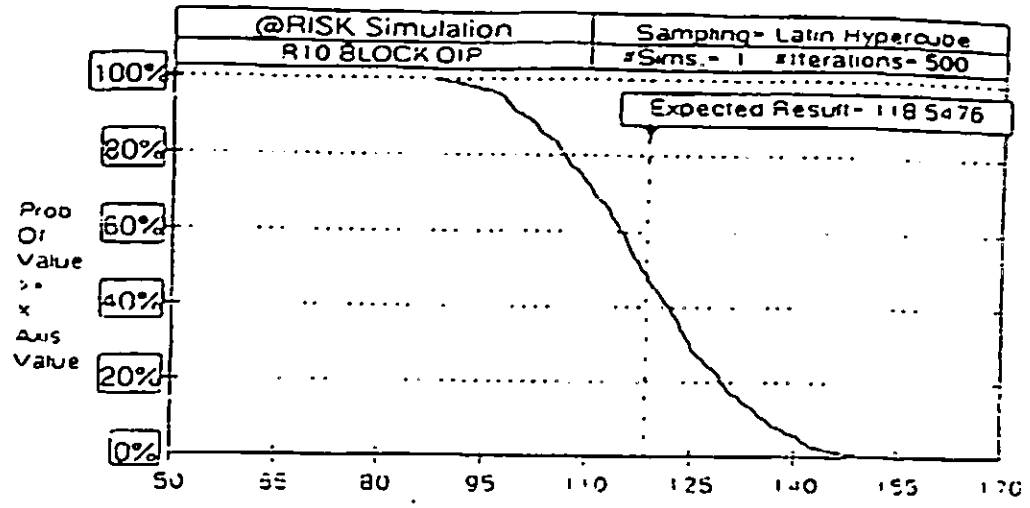


Figure 22A - R10 BLOCK OIL-IN-PLACE, MMBBL

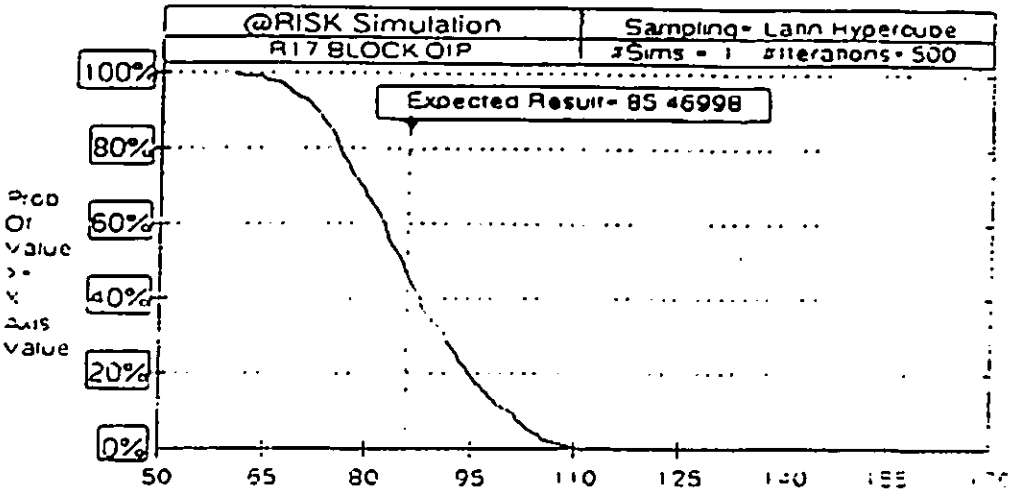


Figure 22B - R17 BLOCK OIL-IN-PLACE, MMBBL

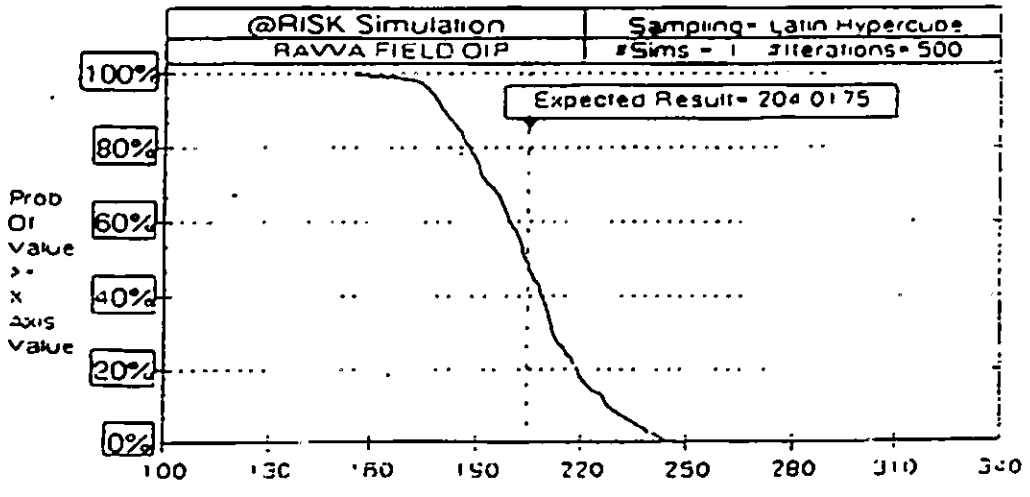


Figure 22C - RAVVA FIELD OIL-IN-PLACE, MMBBL

Command

Figure 22

RAVVA FIELD

OIL-IN-PLACE PROBABILITY DISTRIBUTION

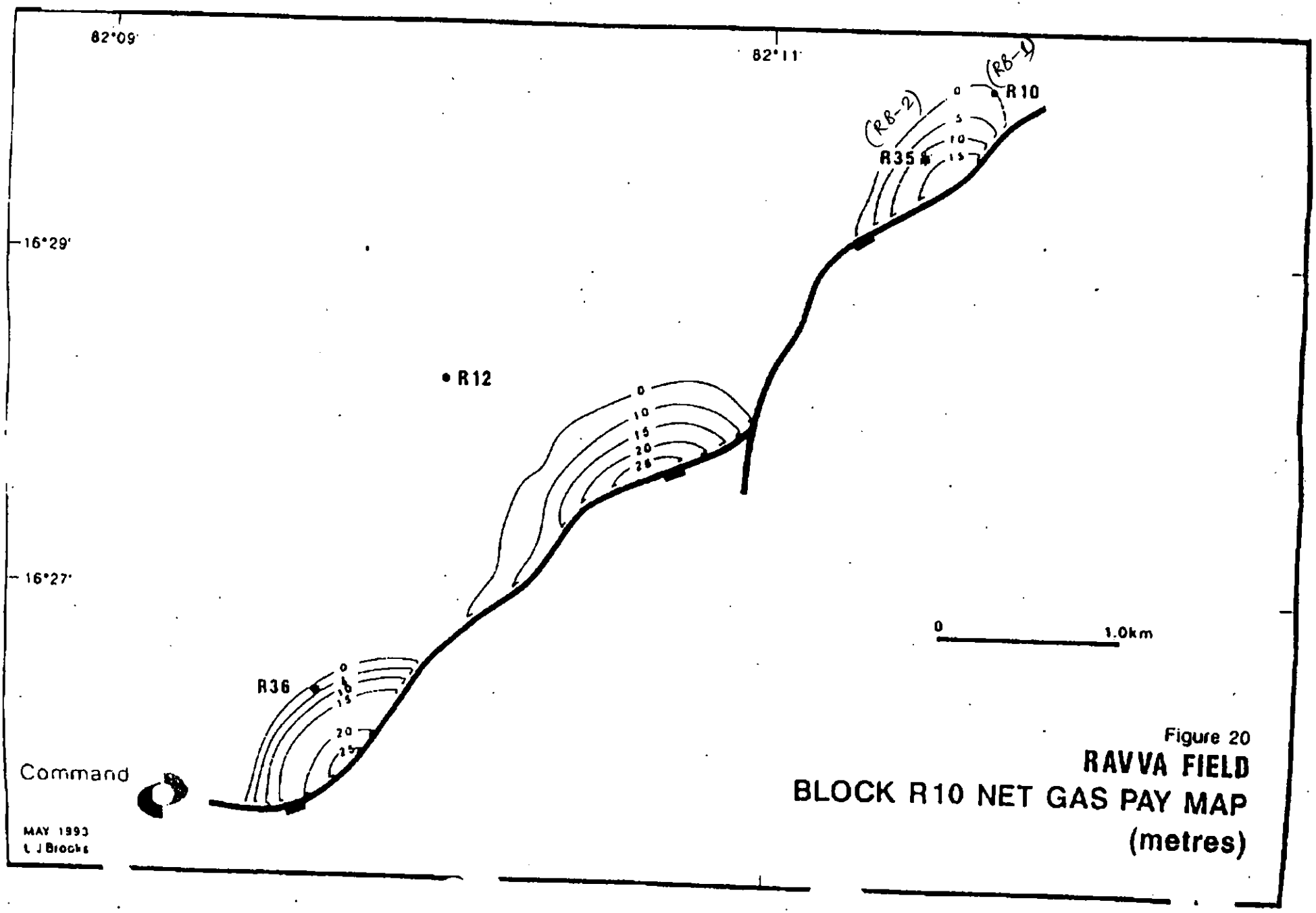
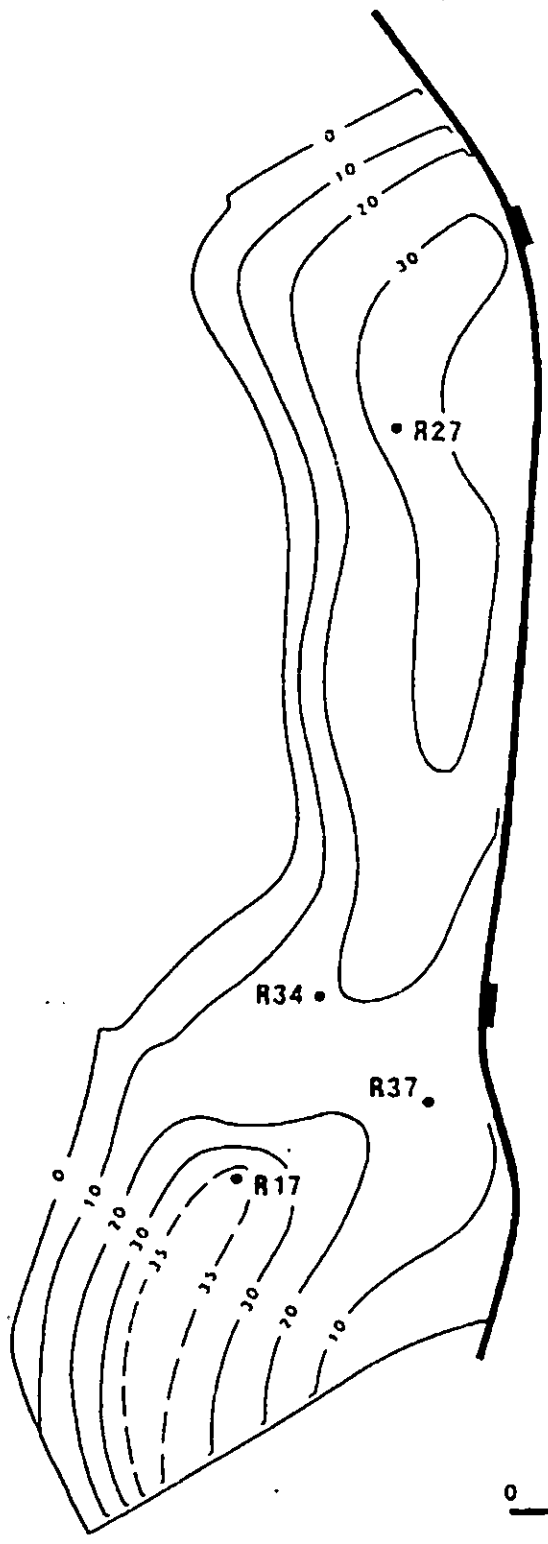


Figure 20

RAVVA FIELD

BLOCK R10 NET GAS PAY MAP

(metres)



Command

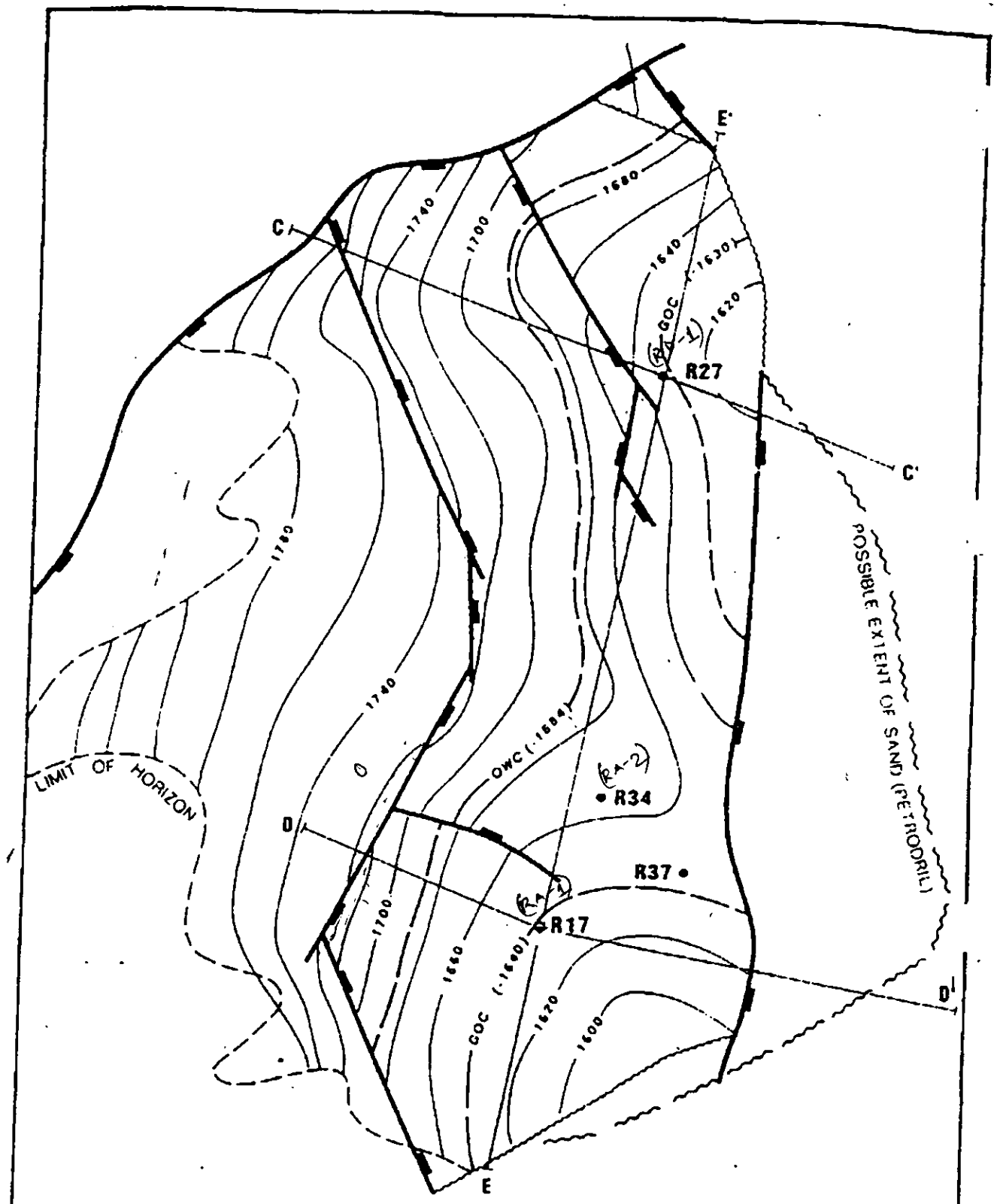
Figure 19

RAVVA FIELD

BLOCK R17 NET OIL PAY MAP

(metres)

MAY 1993
L.J.Brooks



Command

Figure 12

RAVVA FIELD
Block R17
STRUCTURE MAP
MAIN OIL SAND

0 1.0km

JUNE 1993
L.JBrooks

Note : Position of R34 & R37 approximate.

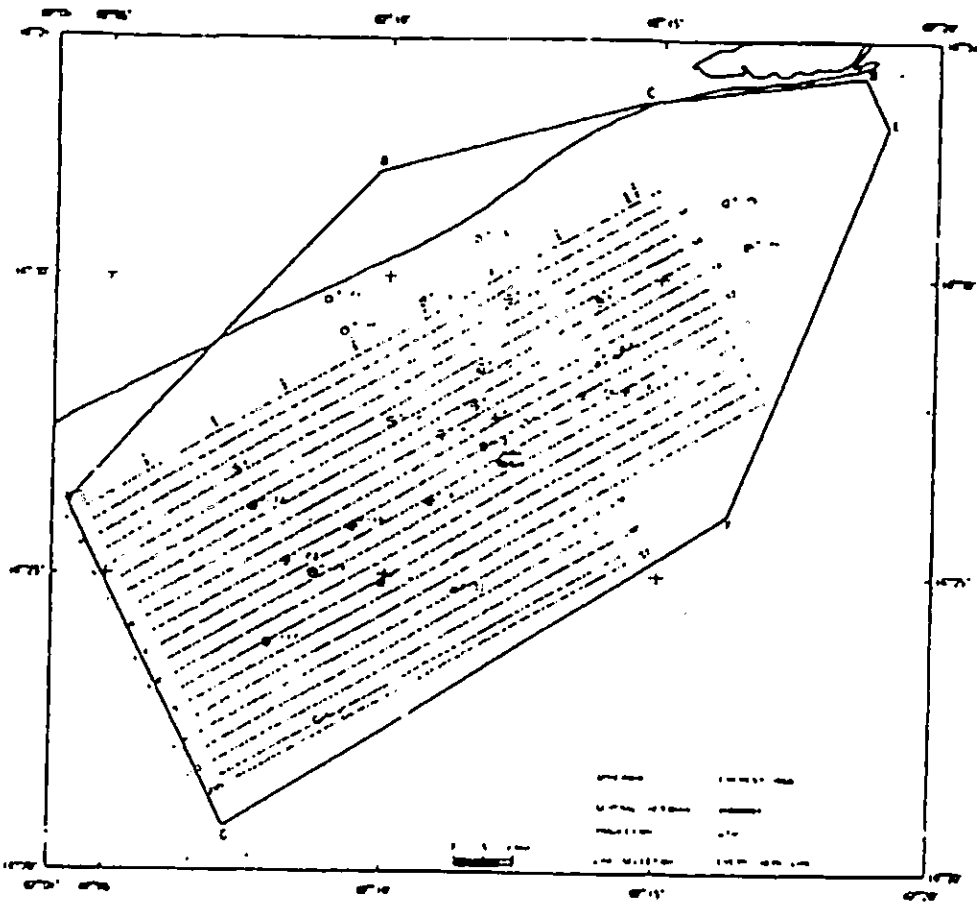
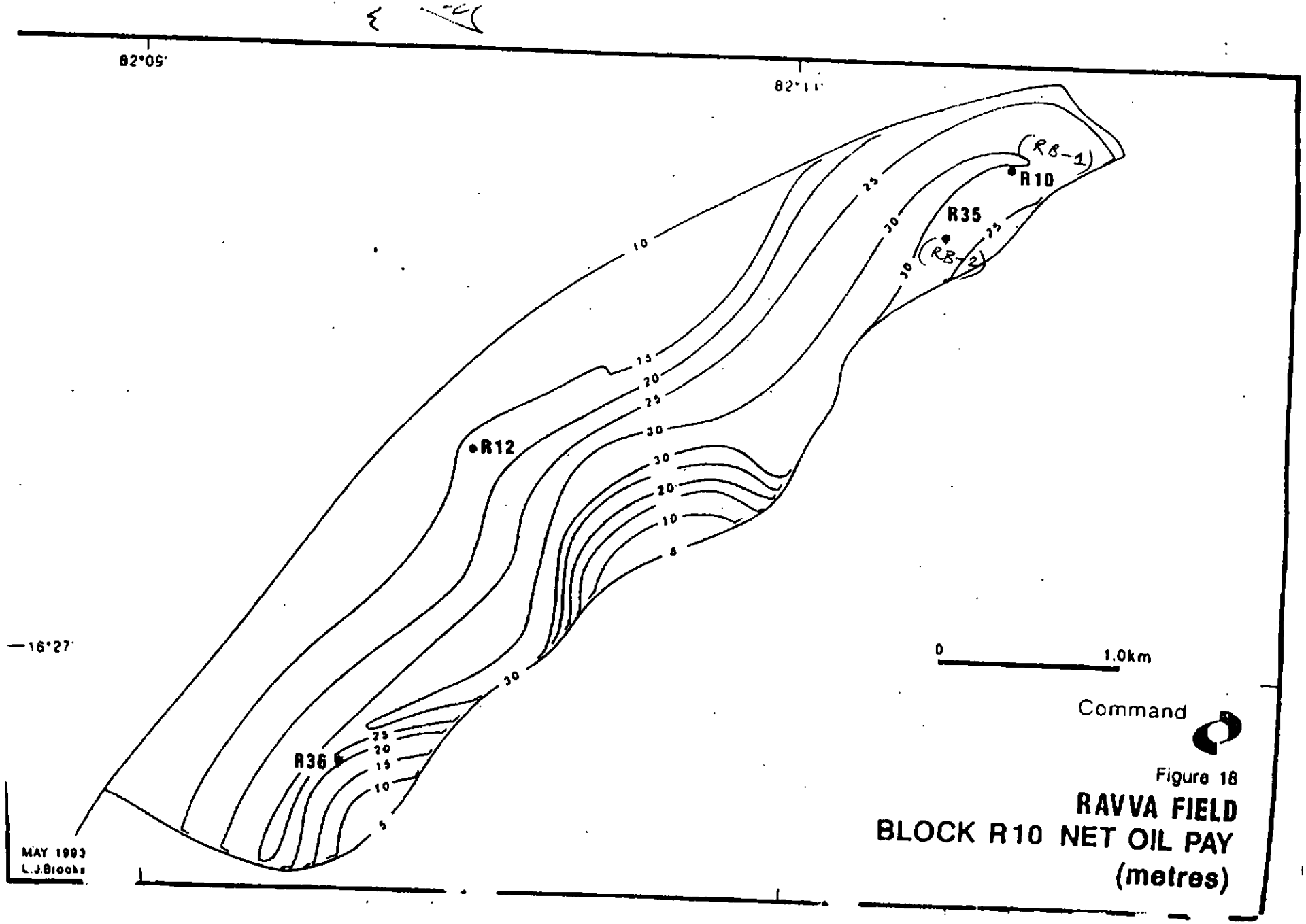


Figure 7

RAVVA FIELD
3D SEISMIC LINES

Command



Command

Figure 18

RAVVA FIELD
BLOCK R10 NET OIL PAY
(metres)

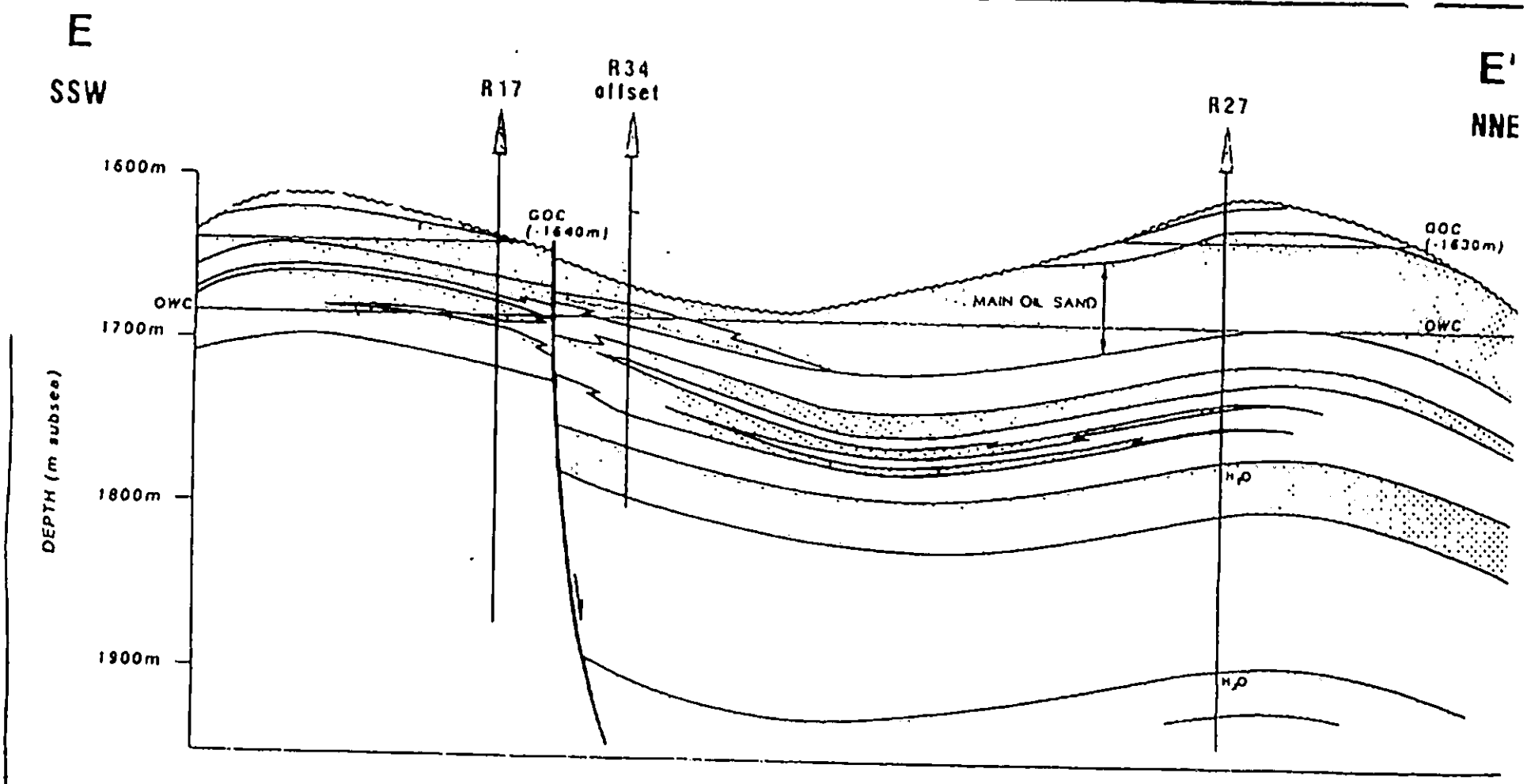
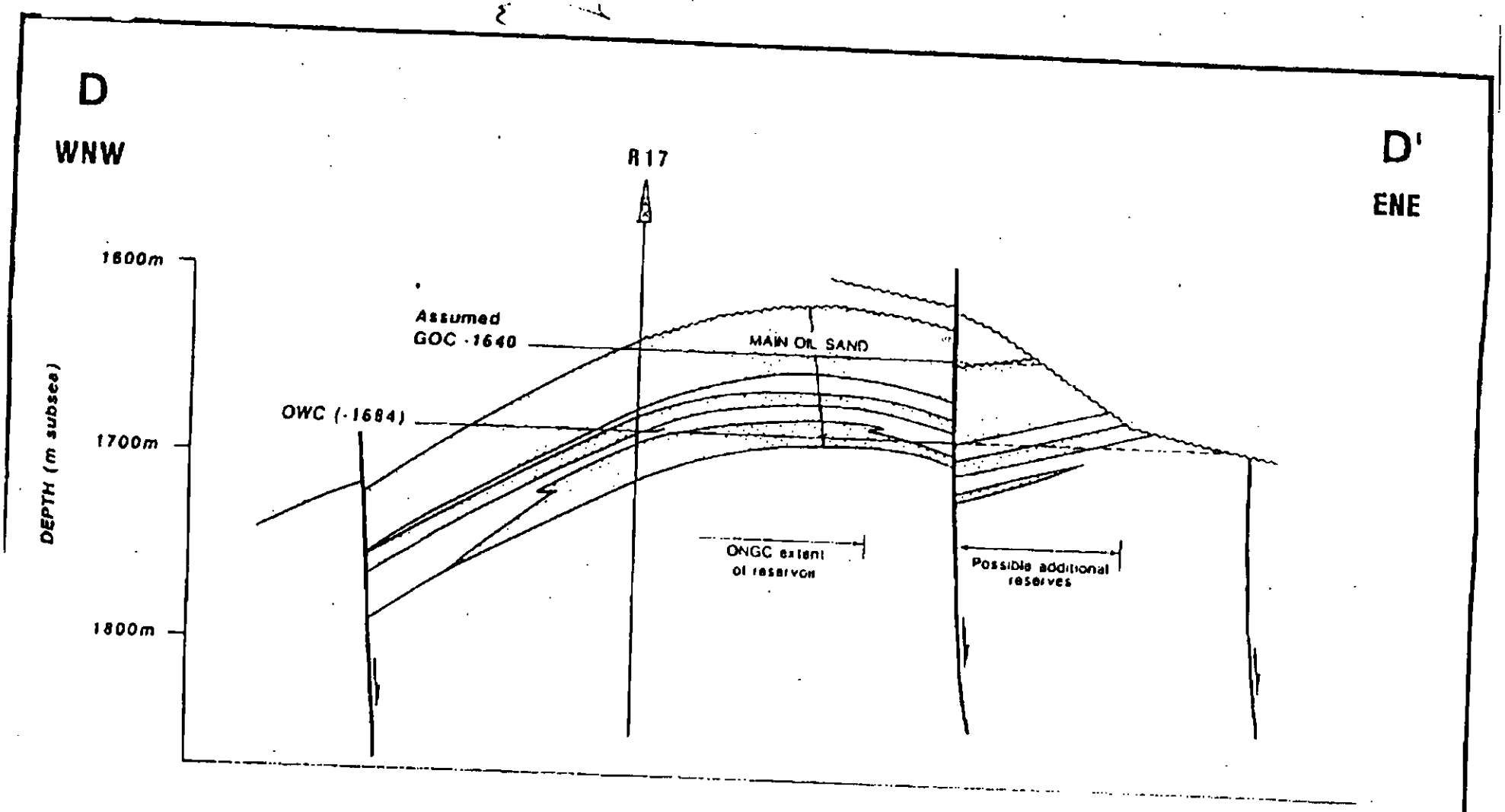


Figure 17

RAVVA FIELD
Block R17
DIAGRAMMATIC STRUCTURAL CROSS SECTION E-E'



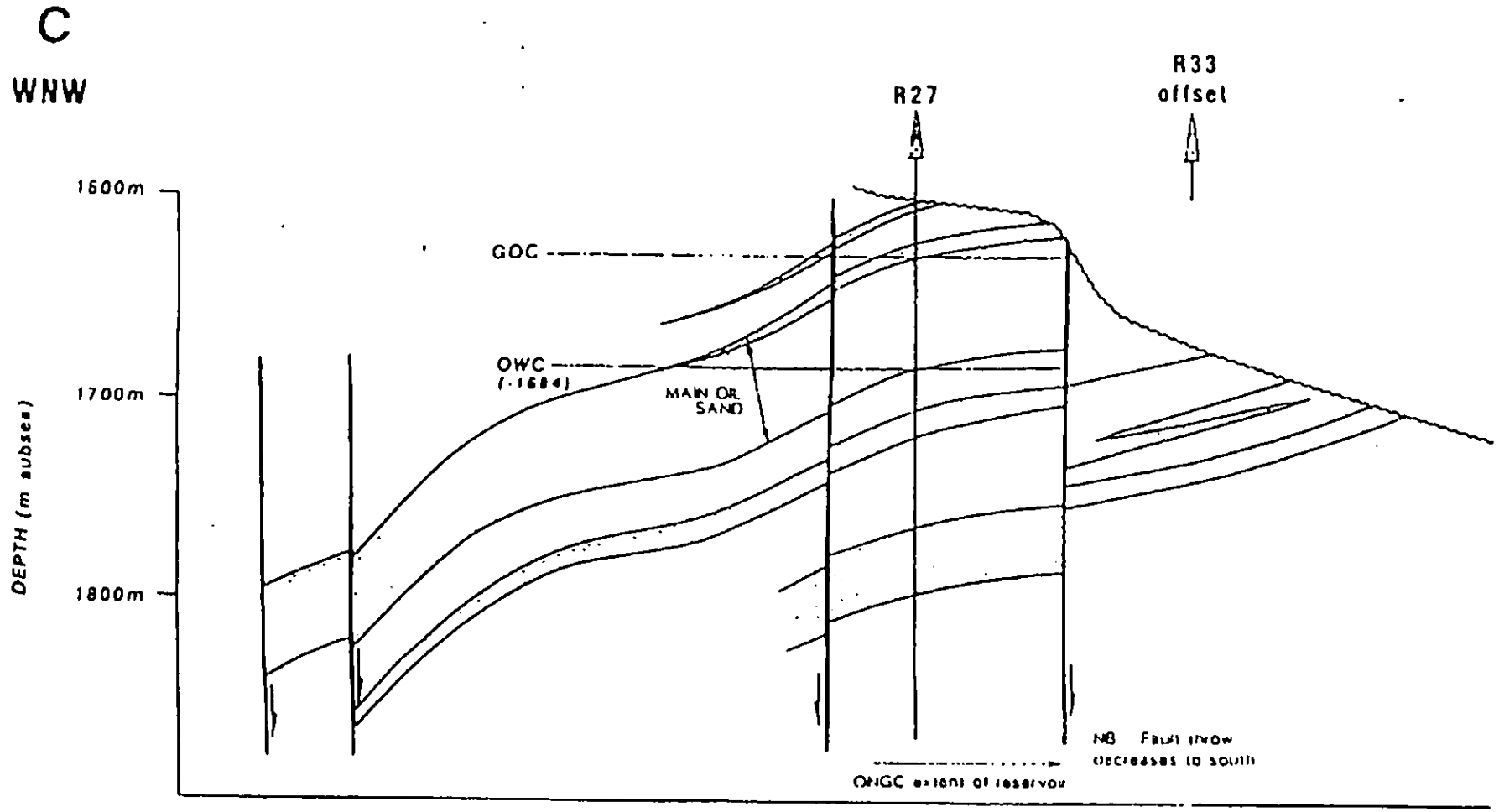
Command

0 500m

MAY 1993

Figure 16

RAVVA FIELD
Block R17
DIAGRAMMATIC STRUCTURAL
CROSS SECTIC D'

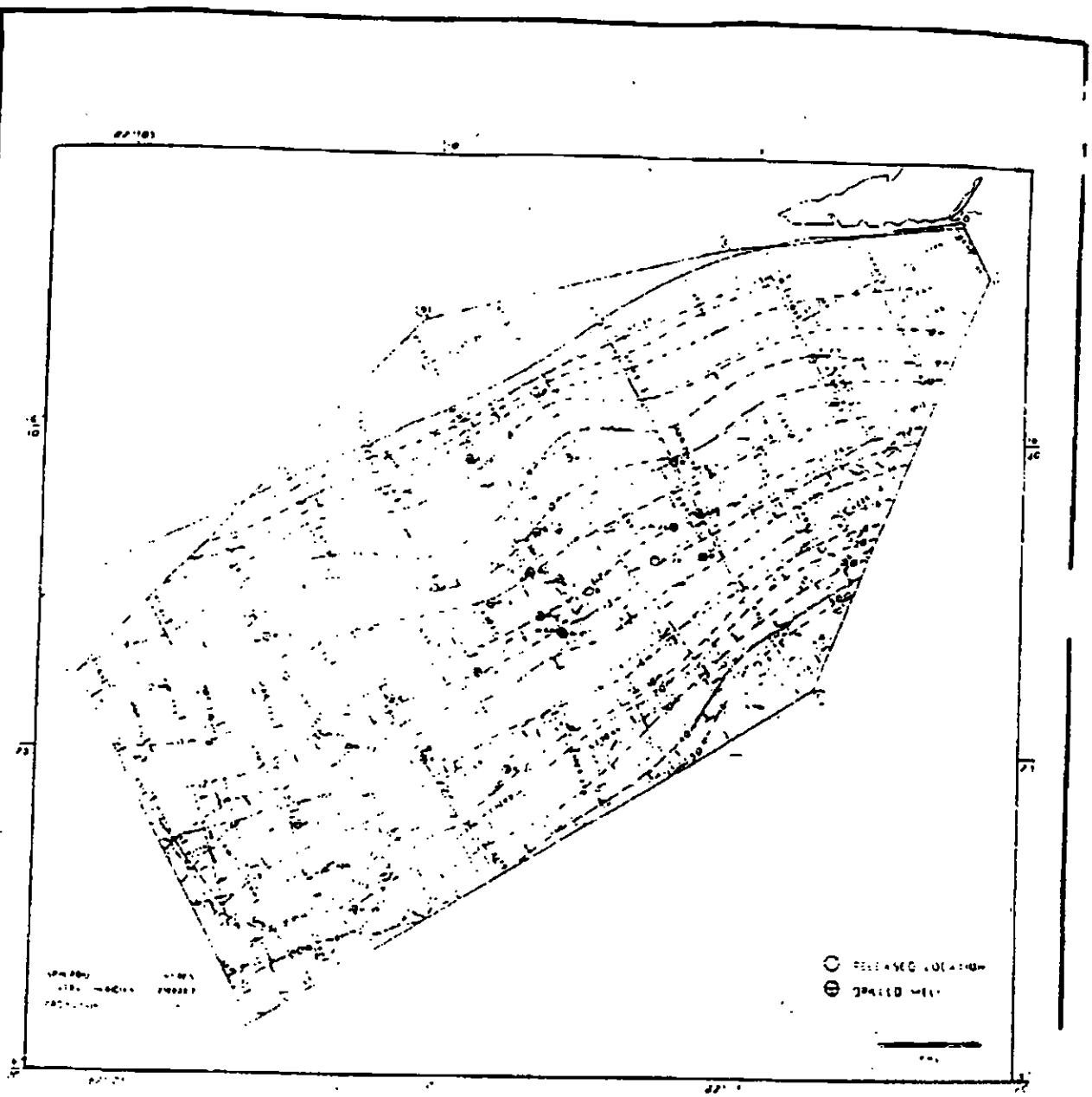


Command

0 500m

Figure 15

RAVVA FIELD
Block R17
DIAGRAMMATIC STRUCTURAL
CROSS SECTION C-C'



Command

Figure 6

RAVVA FIELD

BATHYMETRY AND 2D SEISMIC LINES

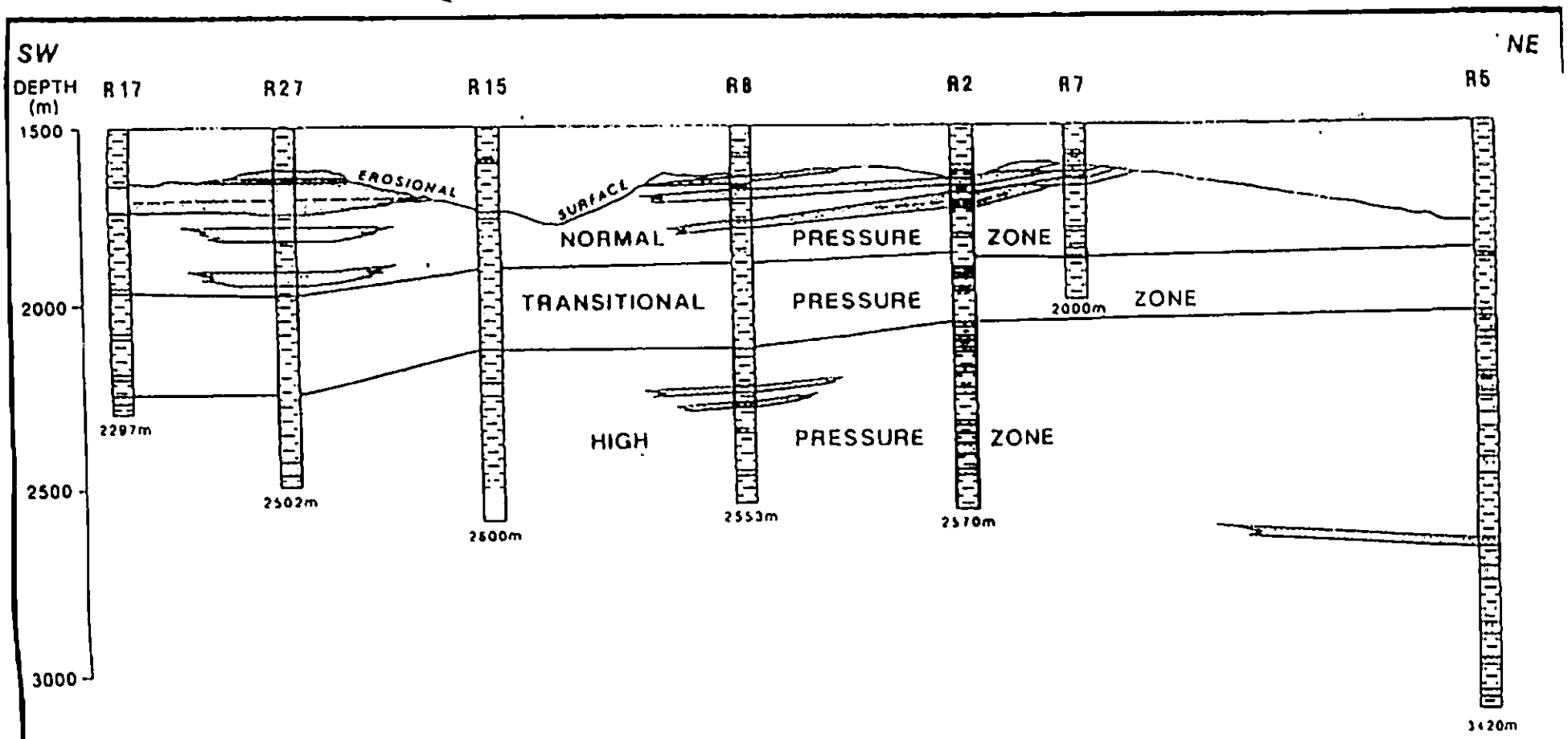


Figure 5

RAVVA FIELD

GEOLOGICAL SECTION ALONG RAVVA FIELD

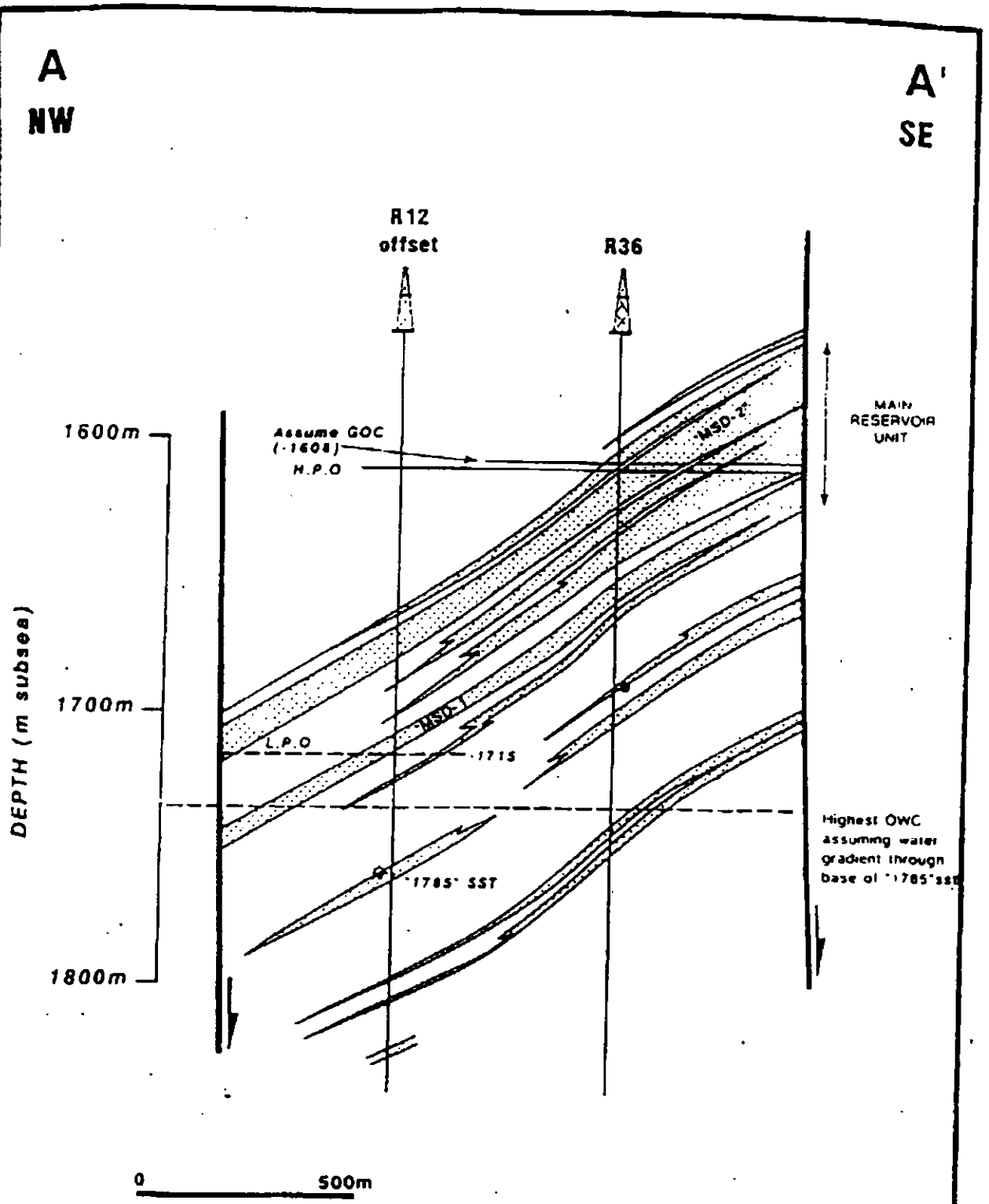


Figure 13

RAVVA FIELD
Block R10
DIAGRAMMATIC STRUCTURAL CROSS SECTION A-A'

Command

MAY 1993
LJBrooks

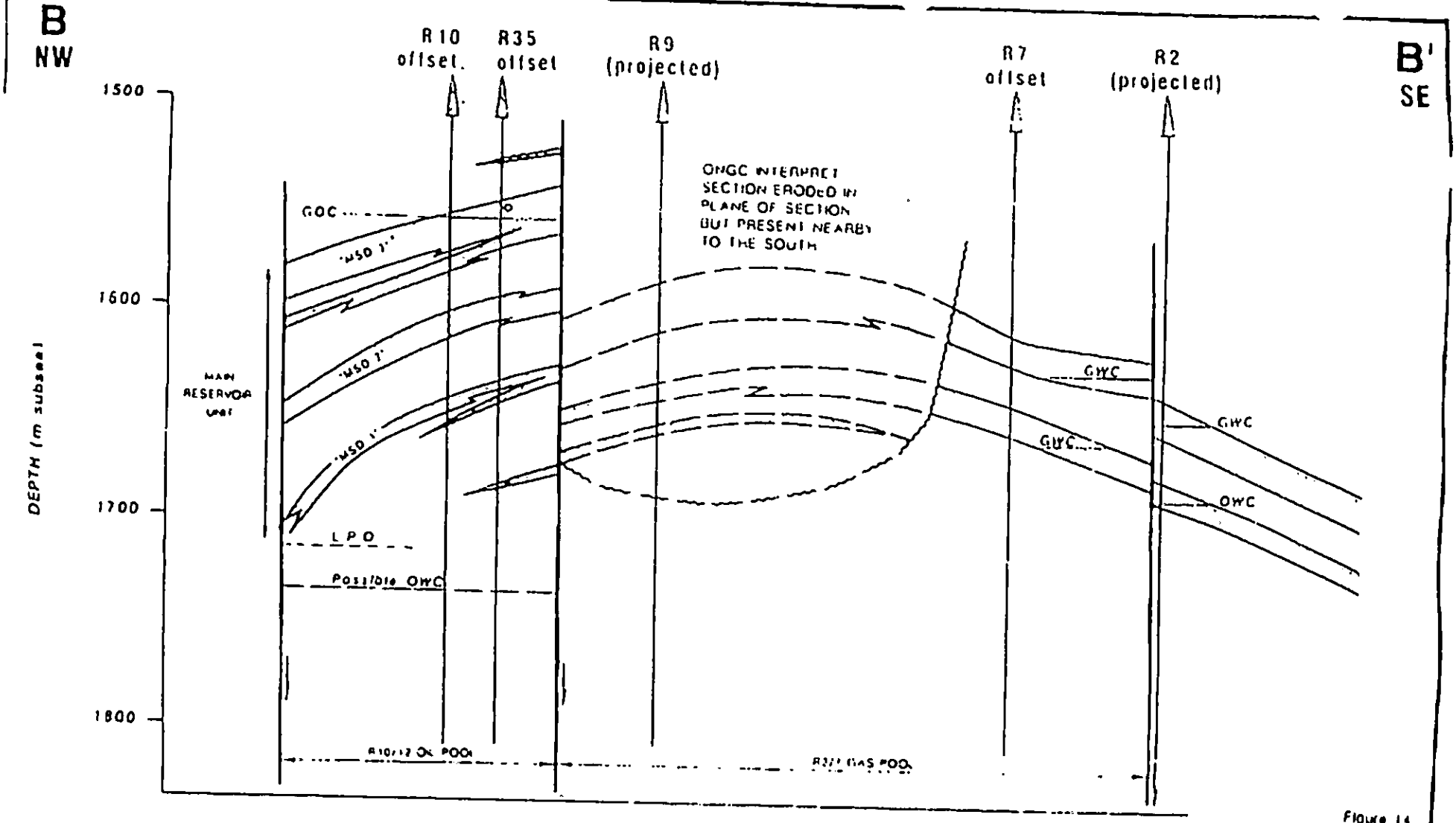


Figure 14

RAVVA FIELD
Block R10
DIAGRAMMATIC STRUCTURAL
CROSS SECTION B-B'

RAVVA FIELD DEVELOPMENT

COMPARISON WITH EQUIVALENT DEVELOPMENT

IN AUSTRALIA

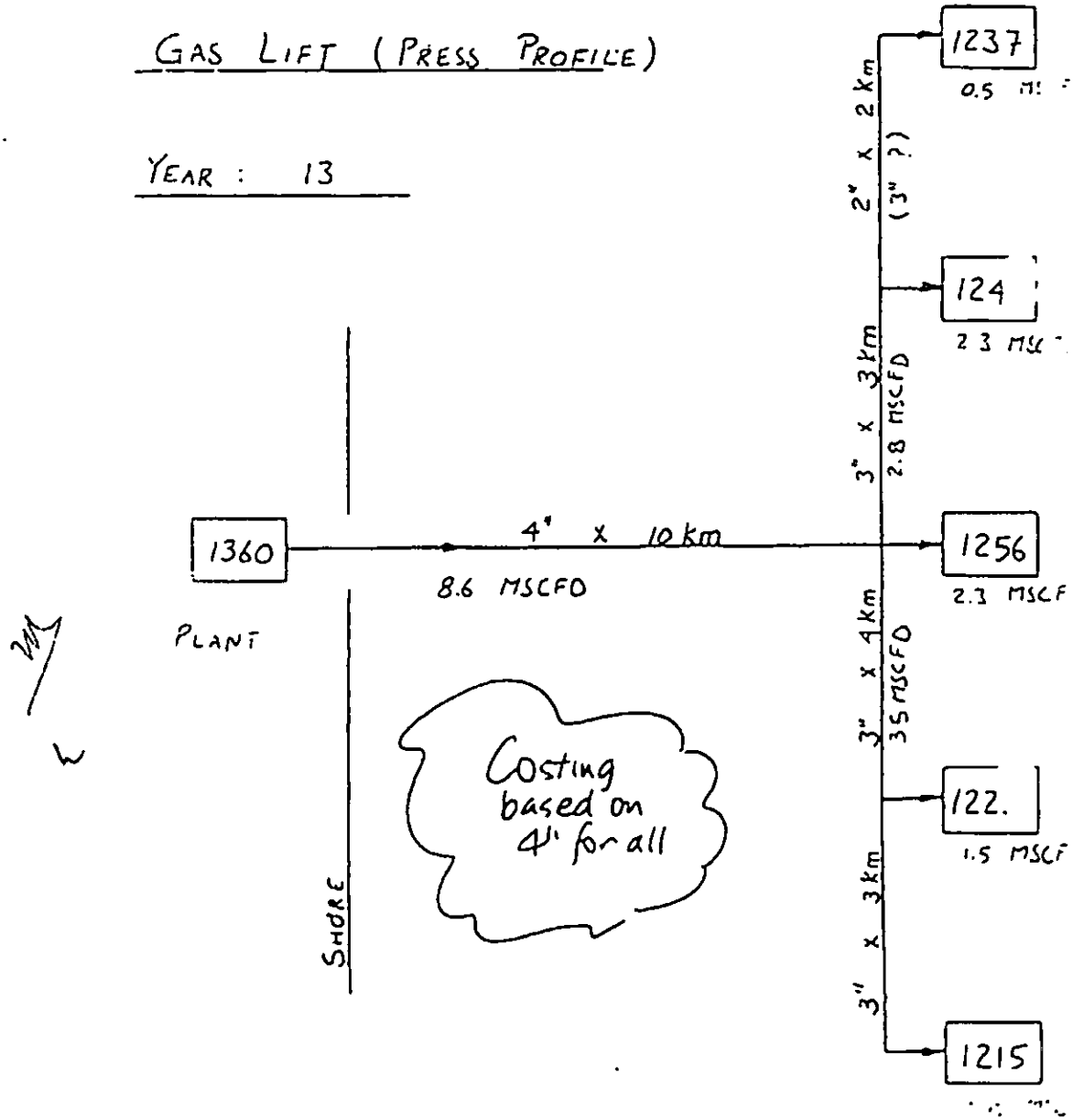
	AUSTRALIAN FIELD	RAVVA
Water depth	15m	10-15m
Distance offshore	2-3 km	10-15 km
Seabed	Very hard	Very soft
Process capacity onshore	60 kbd	60 kbd
Gas lift	Yes	Yes
Water injection	No	Yes
Storage	3 x 350 kbbl tanks	2 x 250 kbbl tanks
Tanker loading line	6 km x 36"	15 km x 20"
Tanker loading buoy	8 pt fixed mooring	CALM
Platforms	3 @ $7 million each	4 @ $7.7 million each
Flowlines	3 x 8" x ± 2km WF 3 x 6 x ± 2 km GL Nil WI	2 x 10" x 12 k WF 1 x 4" x 12 k GL 1 x 10" x 12 k WI
Development cost excluding wells	US$85 million in 1989	US$120 million in 1993
Operating costs (during first year of full production)	US$ 5 million in 1990	US$12 million in 1993

WORLEY ENGINEERING AUSTRALIA

Job No. 20192 Date 18 - '
Client
Project RAVVA PRODUCTION SYSTEM
Subject LINE SIZING
Sheet of By S.Y. Check

GAS LIFT (PRESS PROFILE)

YEAR : 13



NOTES:

ALL PRESS IN PSIA

PIPE LINE CLASS 600#

EXPERIENCE OF KEY PERSONNEL

HUGH WHITE. Operations Advisor, Command Petroleum Holdings N.L.

Mr. White has a total of 22 years active experience in the upstream oil business. In this time he has worked in Australia, U.K. sector of the North Sea and Malaysia, and has occupied positions from Drilling Engineer to General Manager.

Of particular relevance to the development of the Ravva Field is his experience in developing oilfields off the Northwest coast of Australia. In 1987 Mr. White managed the Airlie project which involved the development of two small oilfields in 18 metres of water and 25 km from the nearest land. Two small wellhead towers were designed and installed, a jack-up converted to a production platform, onshore storage built, and an offshore tanker loading facility installed. Production from the fields commenced within six months of obtaining project approval.

The success of the project resulted in a third field being developed and tied into the existing facilities, and the adoption of these techniques by other Operators developing small oilfields in this area

SID FRENCH. Director, Worley Engineering

Mr. French has more than 20 years engineering experience which includes a Doctorate in structural analysis. His offshore experience ranges from field development and other feasibility studies through to project management of new designs and remedial works to existing facilities.

For the last several years he has been extensively involved in minimum cost field developments. He project managed the preliminary and detailed design phases of the Perch and Dolphin platforms - the first monotower structures in Bass Strait, Australia. These were the first gravity based monotowers and proved very cost effective. At the same time he was involved in pipeline cost reduction studies and other areas of cost minimisation for field developments.

Also during that period Mr. French has led teams carrying out feasibility studies for several other fields in Australia and offshore China. These have all followed the theme of structural simplicity, ease of fabrication and flexibility of installation. By applying a rigorous approach of minimising offshore process facilities, savings not only in installed cost but also ongoing offshore maintenance are achieved

RICHARD WHILLAS. Engineering Manager, Worley Engineering

Mr. Whillas has 24 years experience which covers work in the offshore industry in the North Sea, South East Asia and Australia. As project manager for multidisciplinary teams he has lead feasibility studies and detailed designs for projects ranging up to major platforms such as BYR-A and BYB-A for Sarawak Shell Berhad. His years spent in Brunei and Malaysia have given him broad

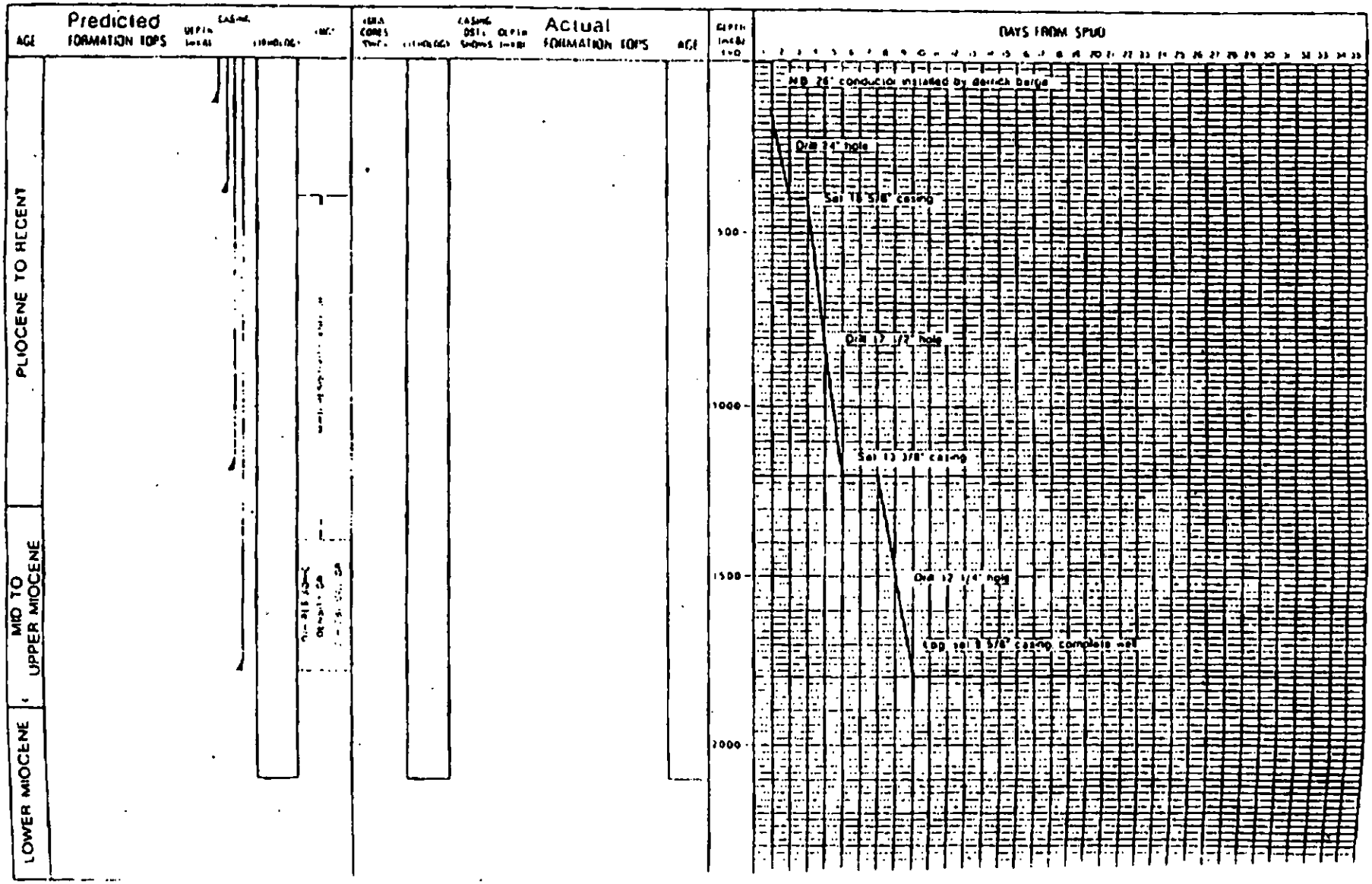
Permit
Basin Kimberley Geographic/Geological
Spud Date
Provisional

Latitude
SP
Elevation

Command Petroleum Holdings NL

Provisional Drill Curve and Section for Vertical Well

Contractor TBA
Rig No TBA
Type Jack-up



Ravva Field Development

Anticipated Management Structure
for Madras Operations Office and On-site Supervisor

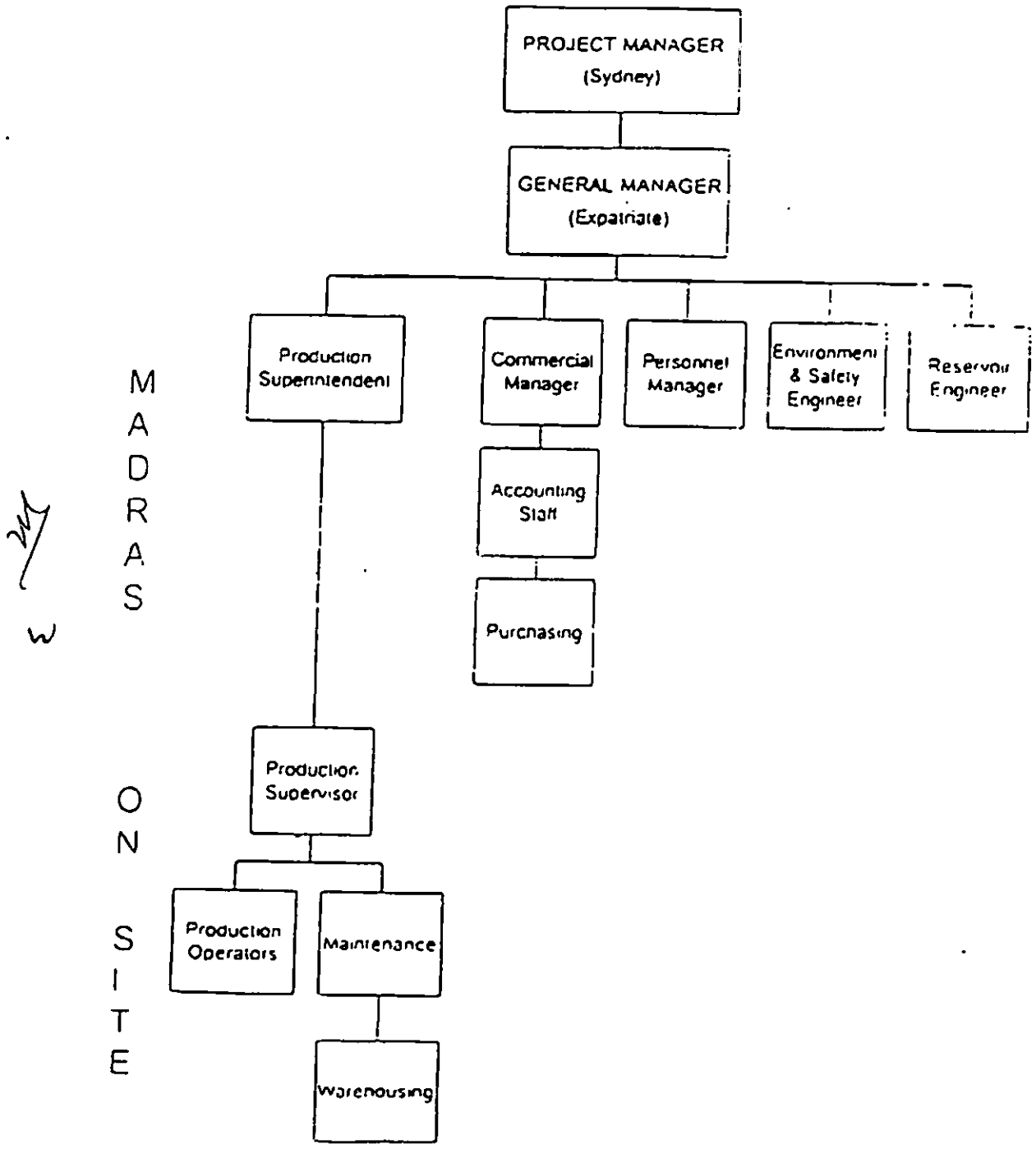


Figure 48

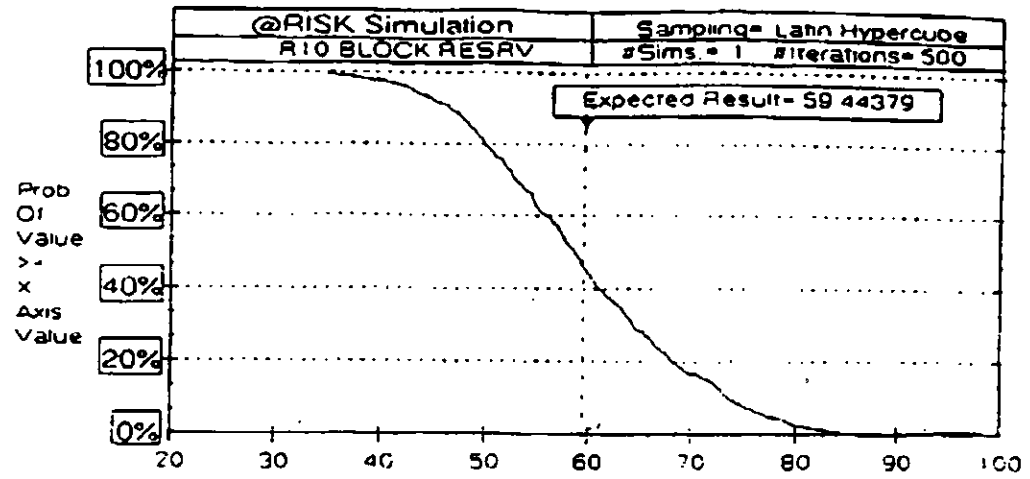


Figure 24A - R10 BLOCK RECOVERABLE RESERVES, MMBBL

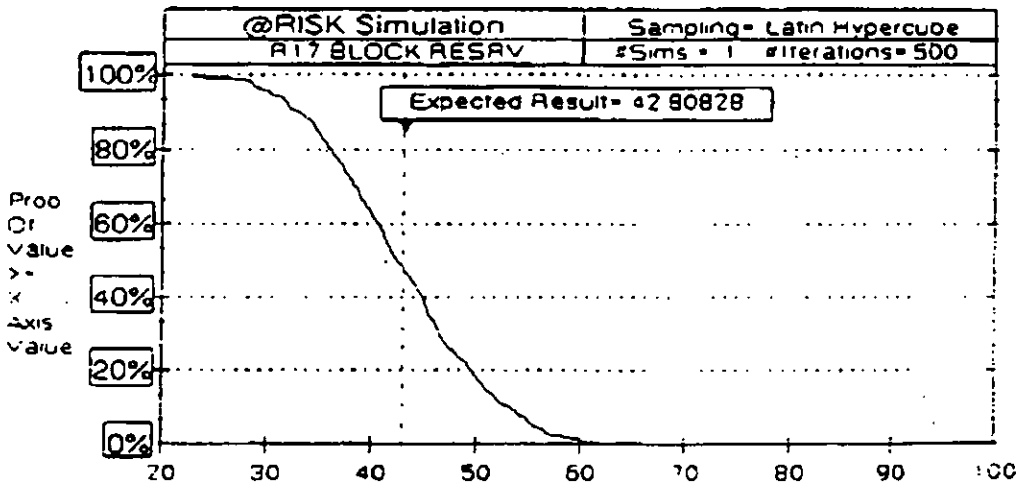


Figure 24B - R17 BLOCK RECOVERABLE RESERVES, MMBBL

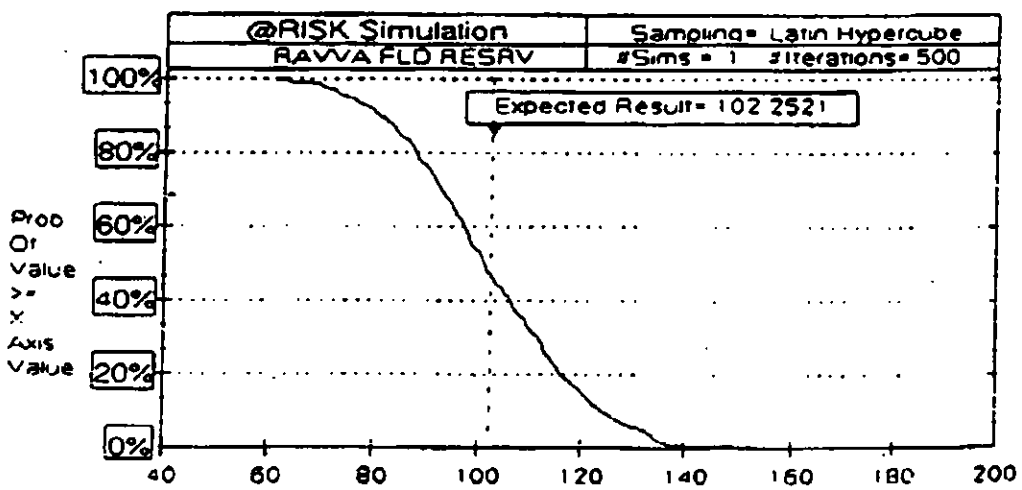


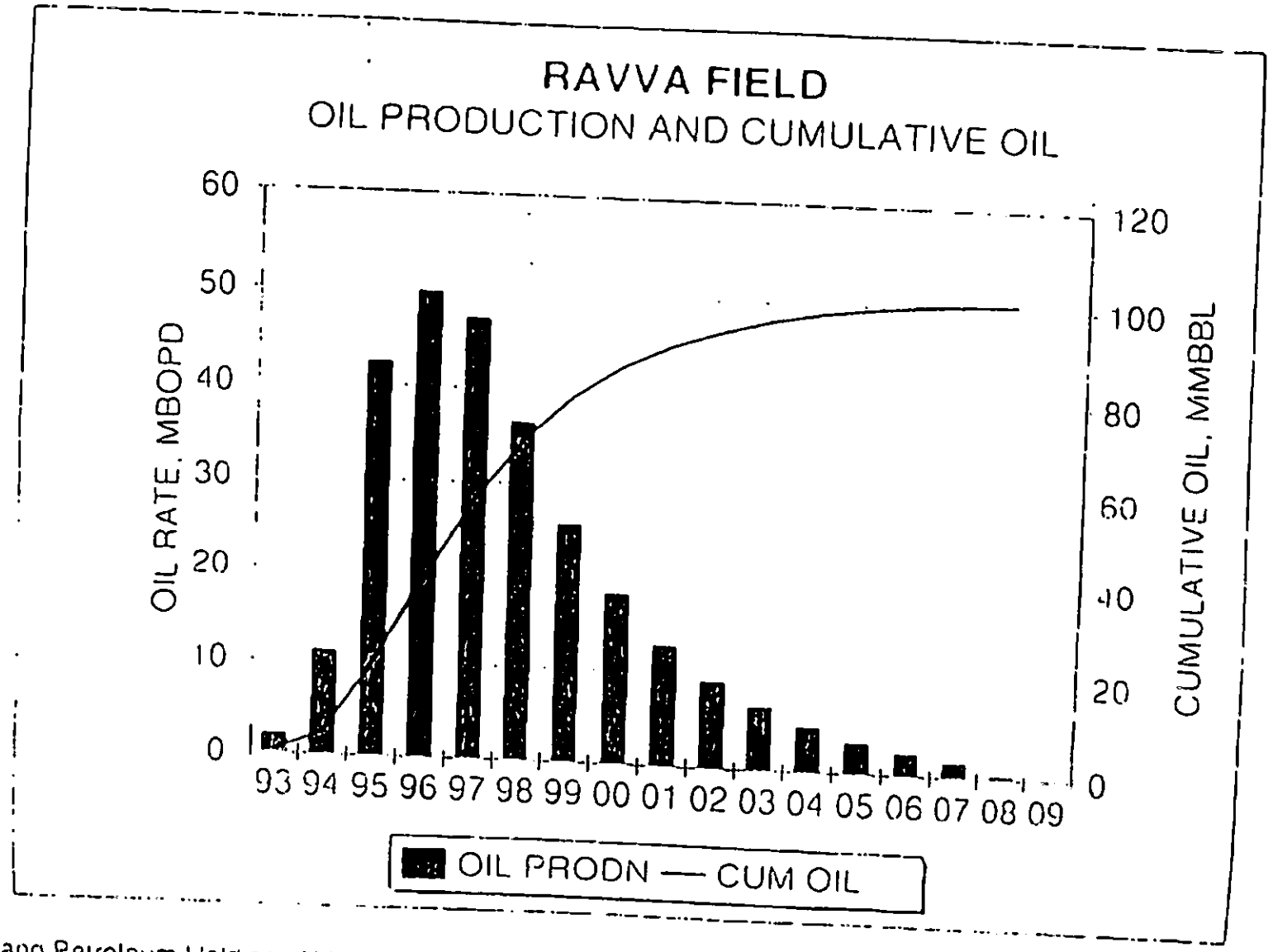
Figure 24C - RAVVA FIELD RECOVERABLE RESERVES, MMBBL

Command

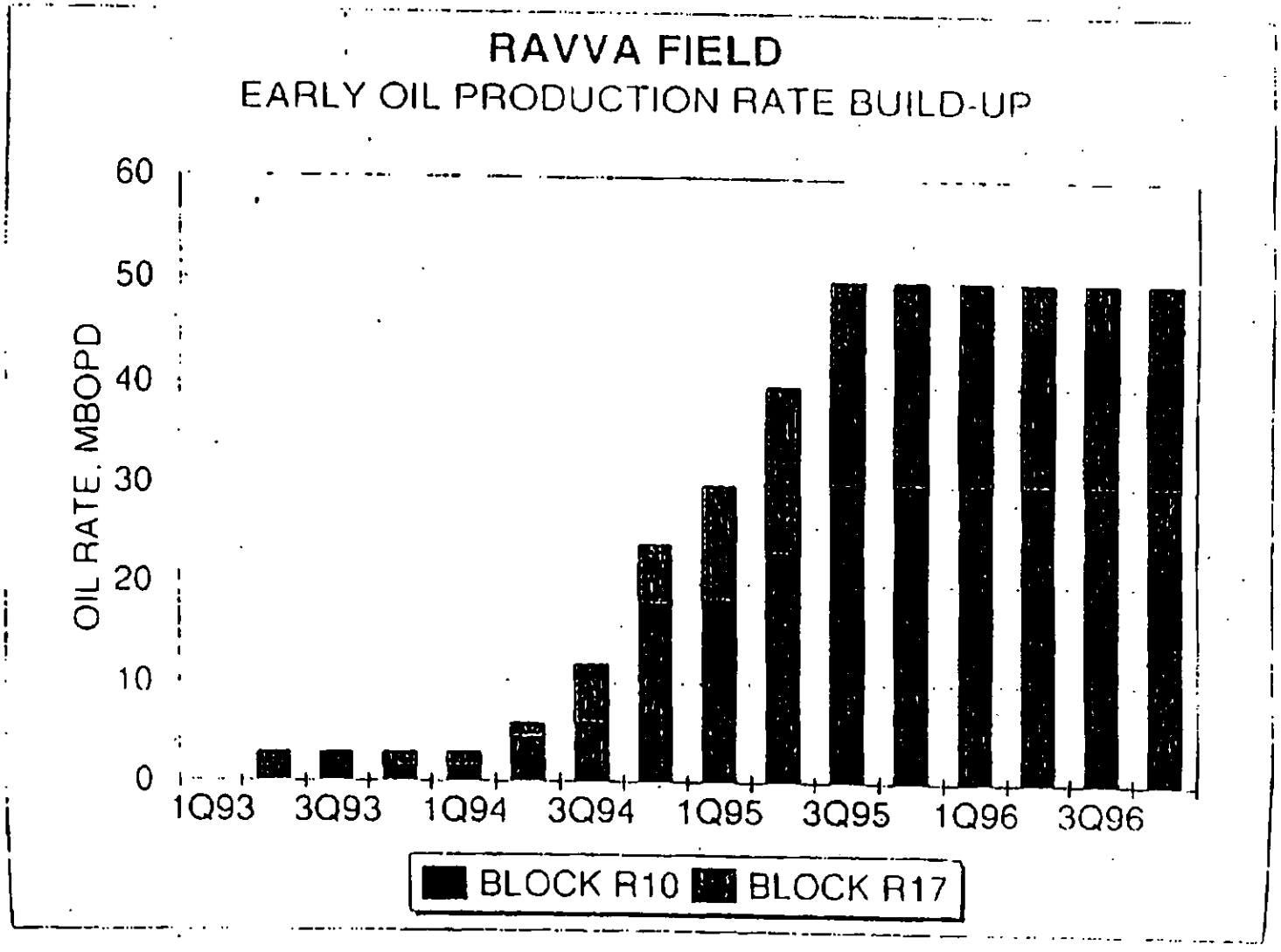
Figure 2

RAVVA FIELD

RECOVERABLE RESERVES PROBABILITY DISTRIBUTION

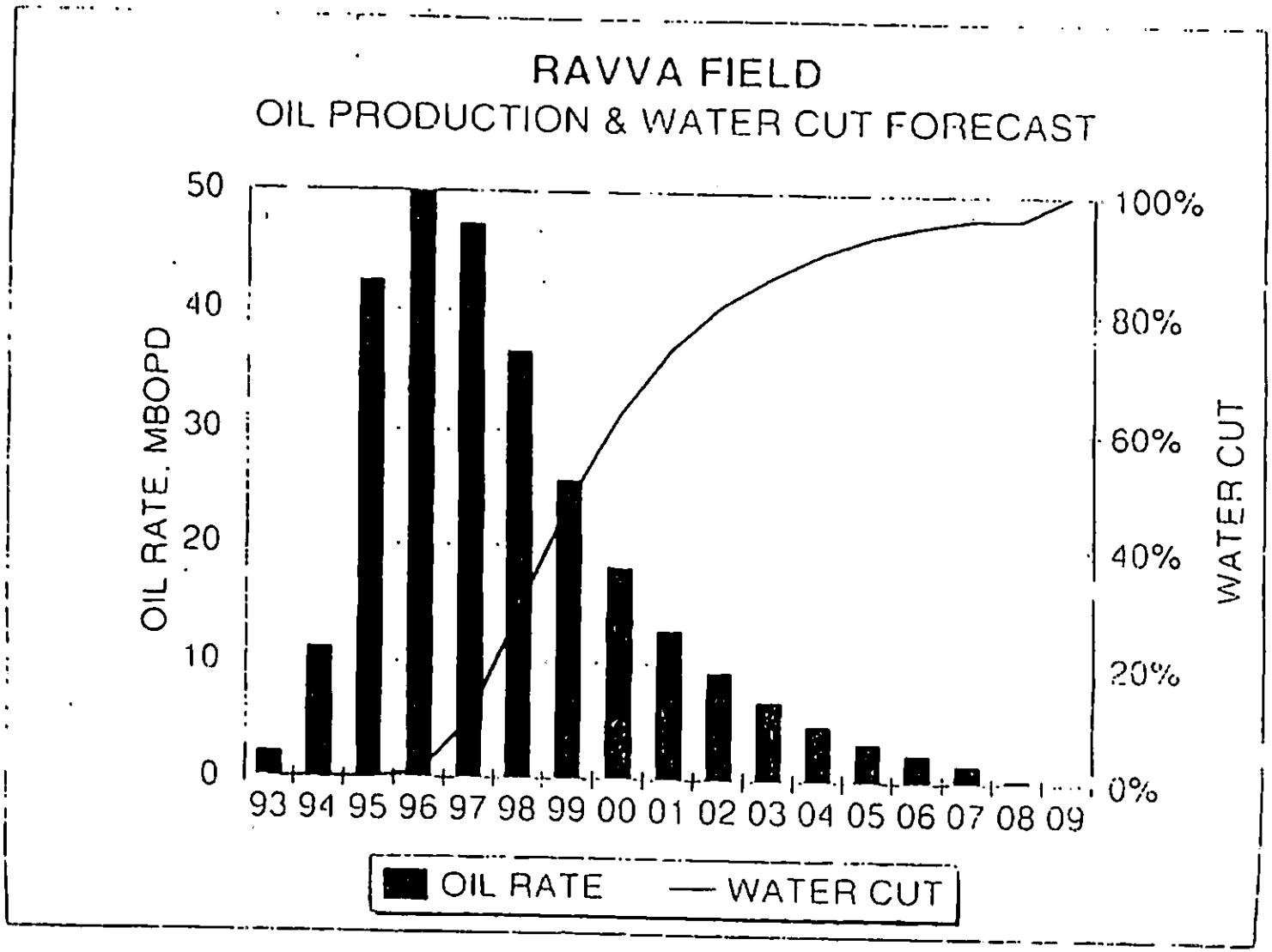


Commano Petroleum Holdings N L



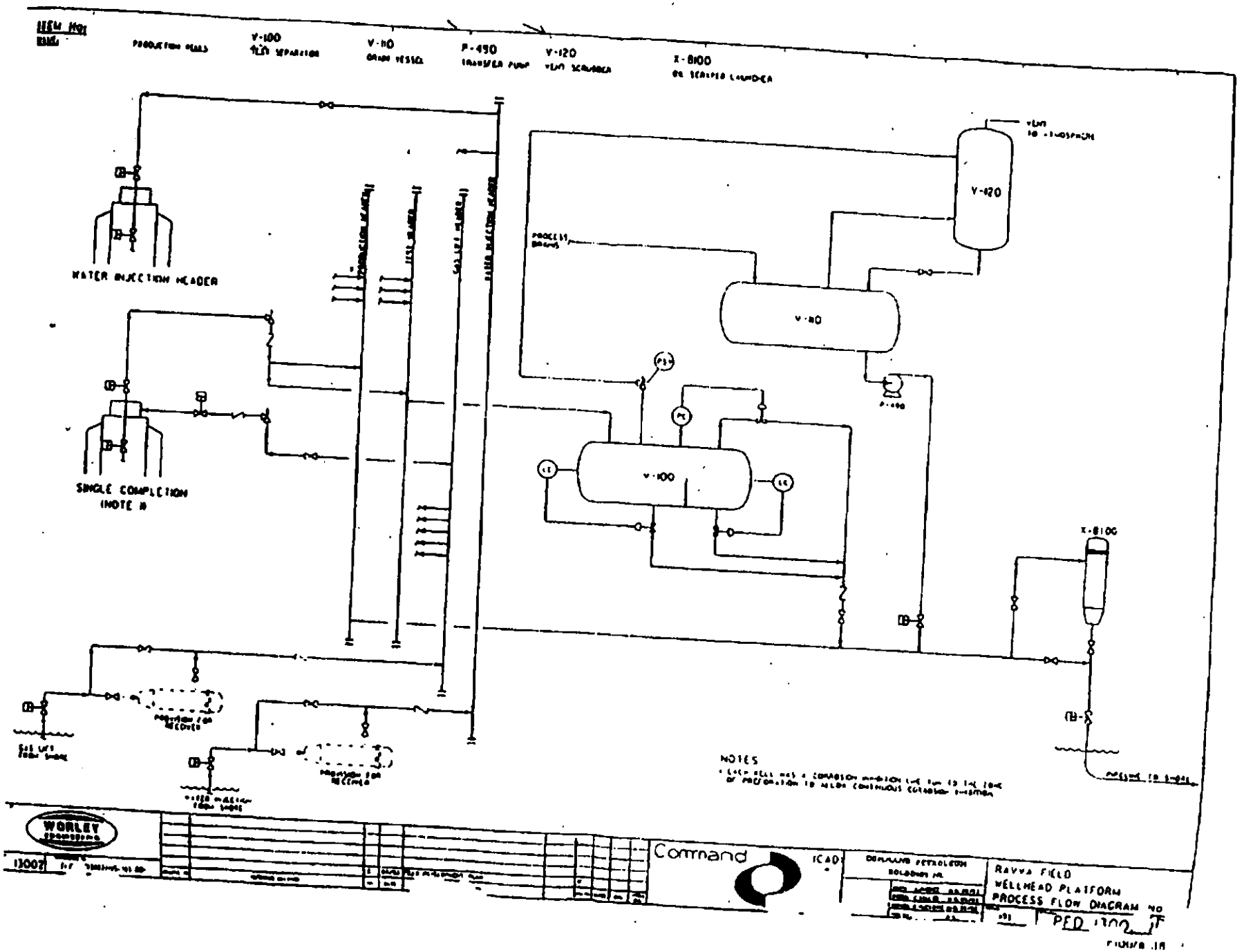
Command Petroleum Holdings N L

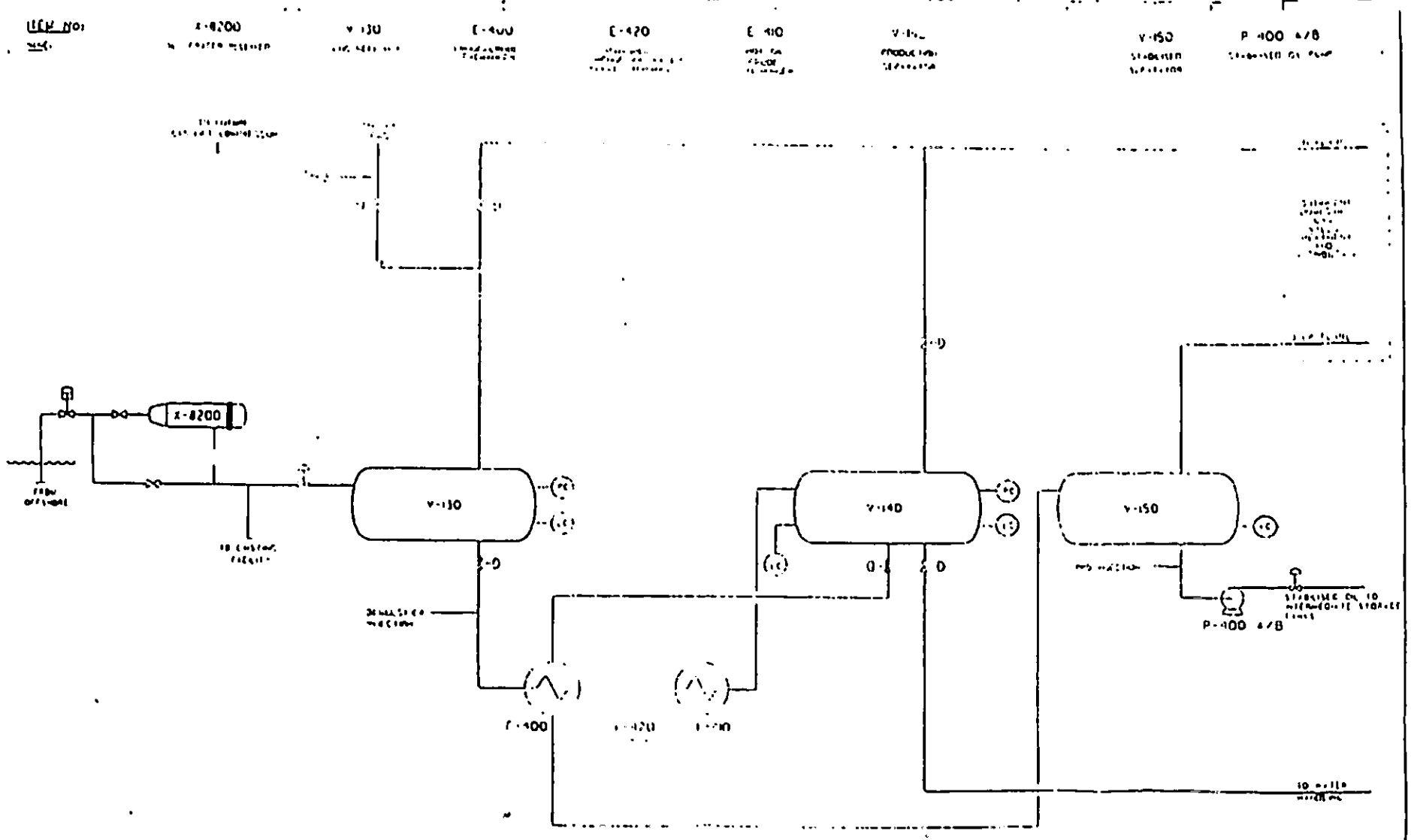
Figure



Command Petroleum Holdings N L

Figure 18

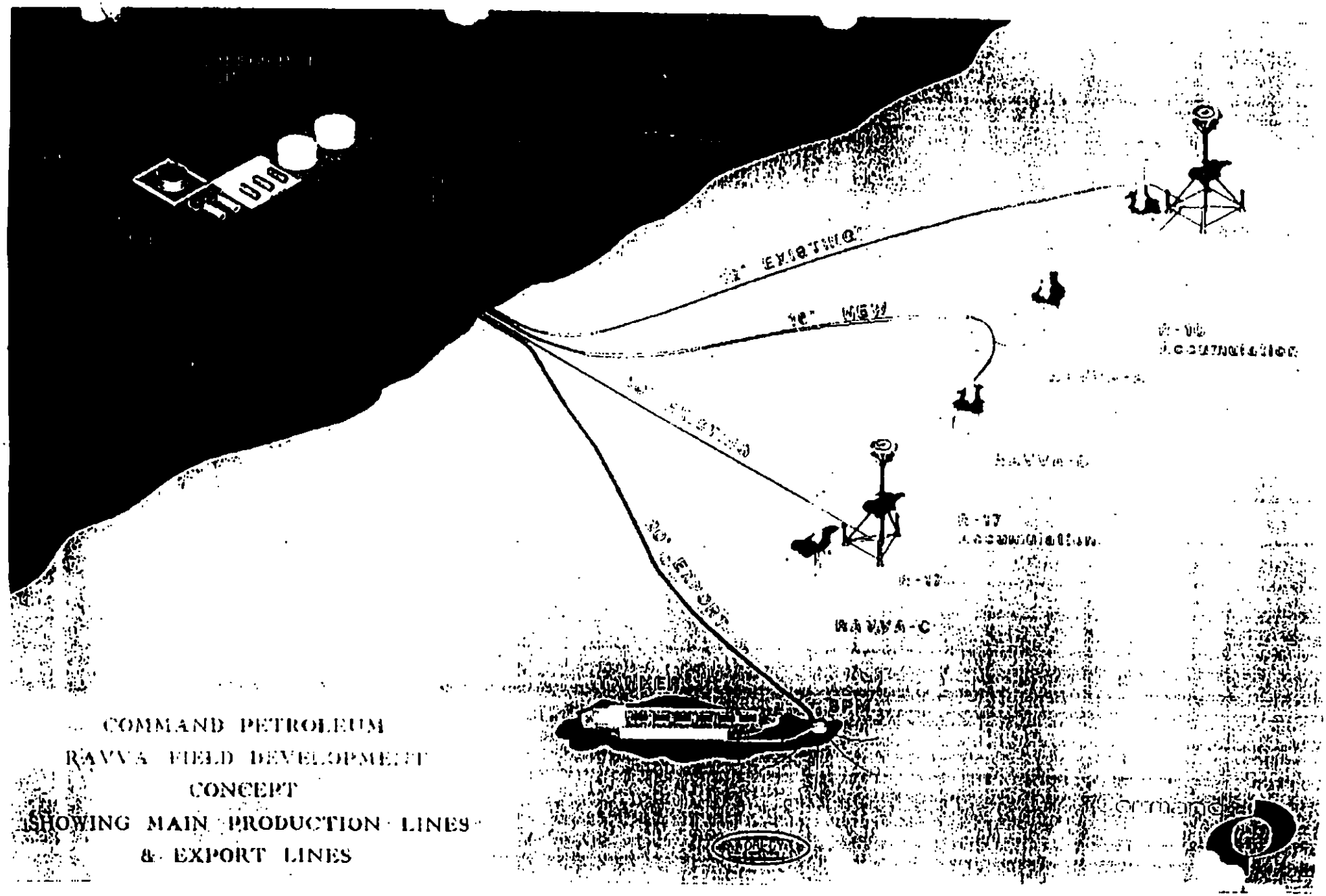

V-100
V-110
P-490
V-120
X-8100
V-420
V-80
V-100
X-8100
WATER INJECTION HEADER
SINGLE COMPLETION
NOTES
WORLEY
Command
RAVVA FIELD
WELLHEAD PLATFORM
PROCESS FLOW DIAGRAM
PED 1702 JF



WORLEY

RAVVA FIELD
CRUDE STABILISATION TRAIN
PROCESS FLOW DIAGRAM NO 2

PFD 1300. 0



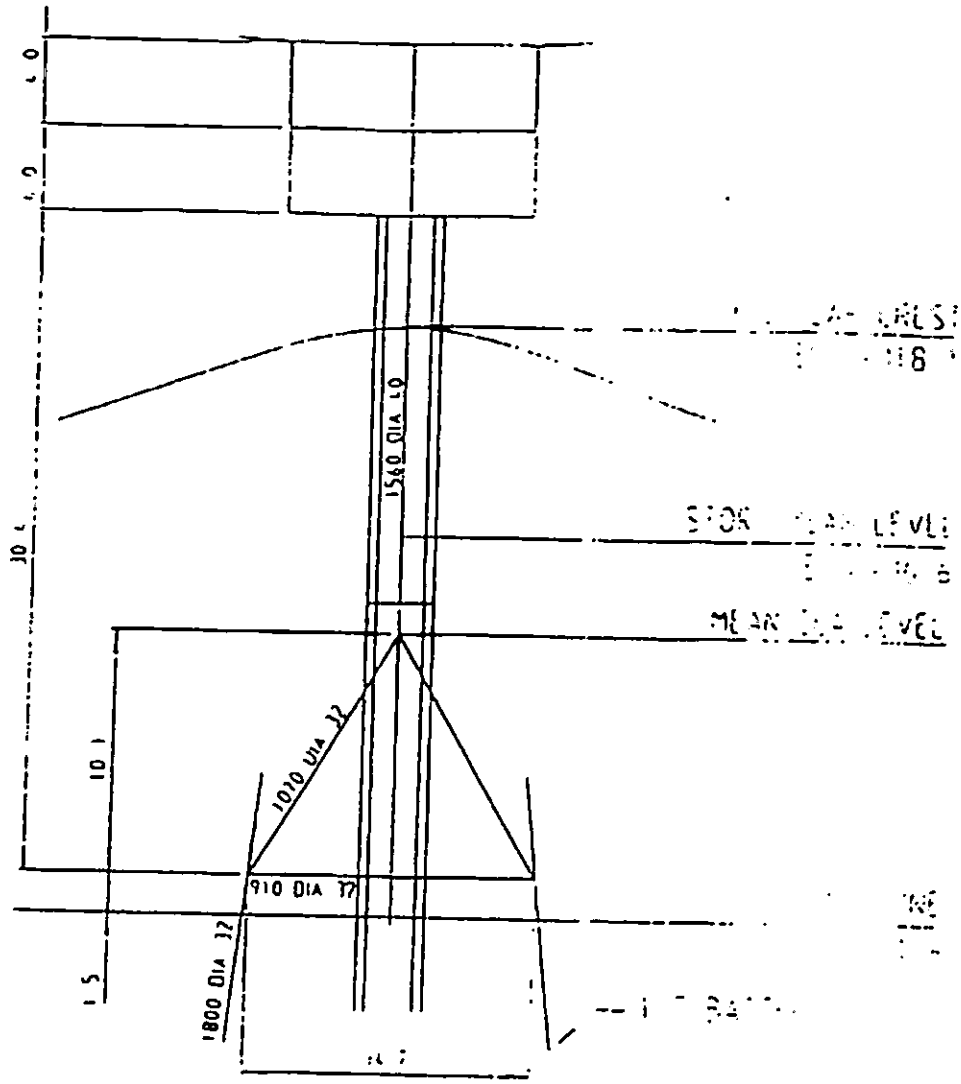
COMMAND PETROLEUM

RAVVA FIELD DEVELOPMENT

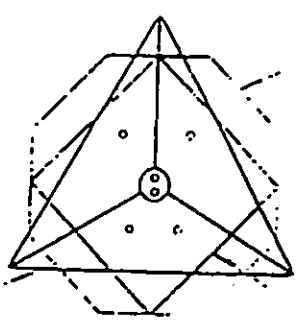
CONCEPT

SHOWING MAIN PRODUCTION LINES

& EXPORT LINES

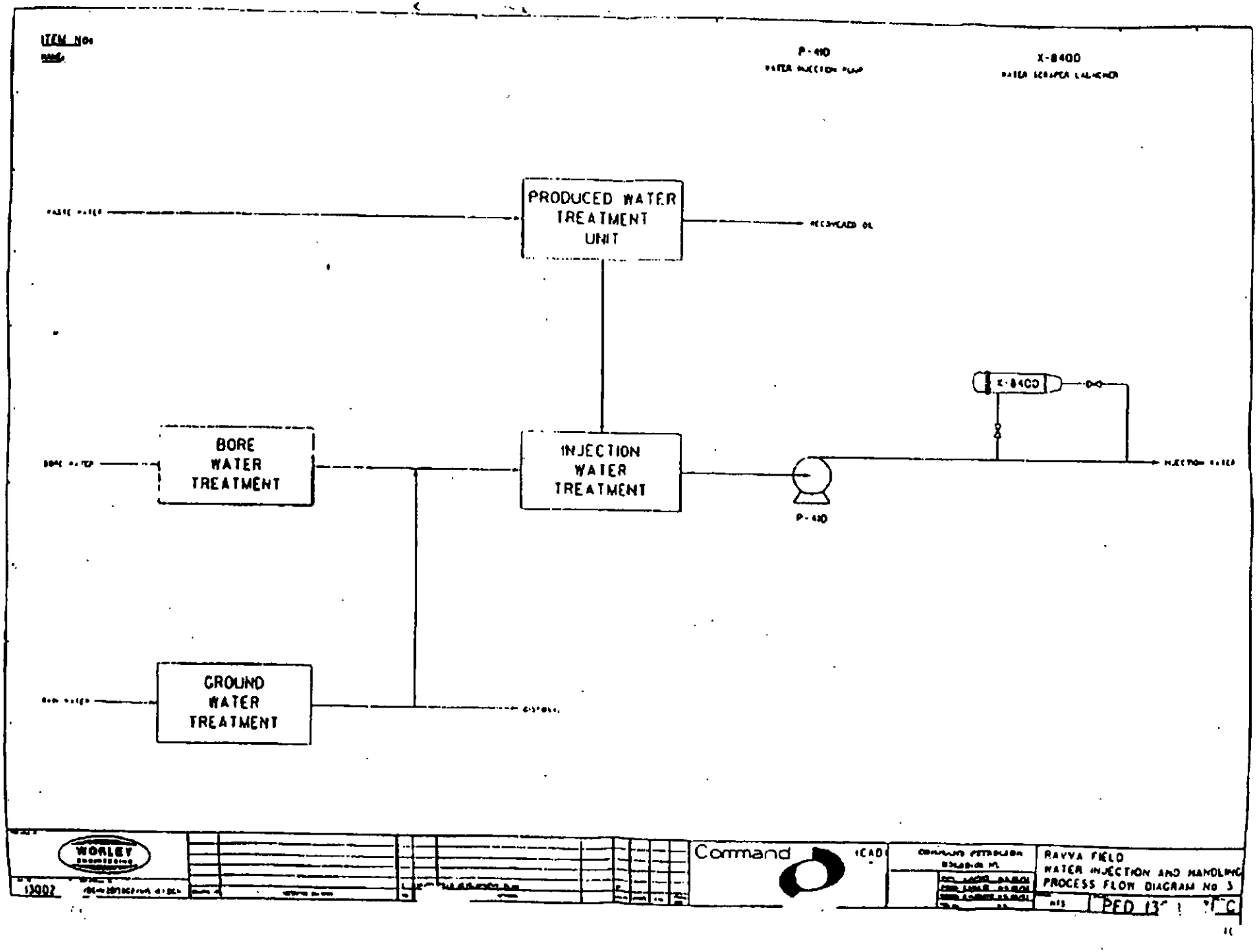


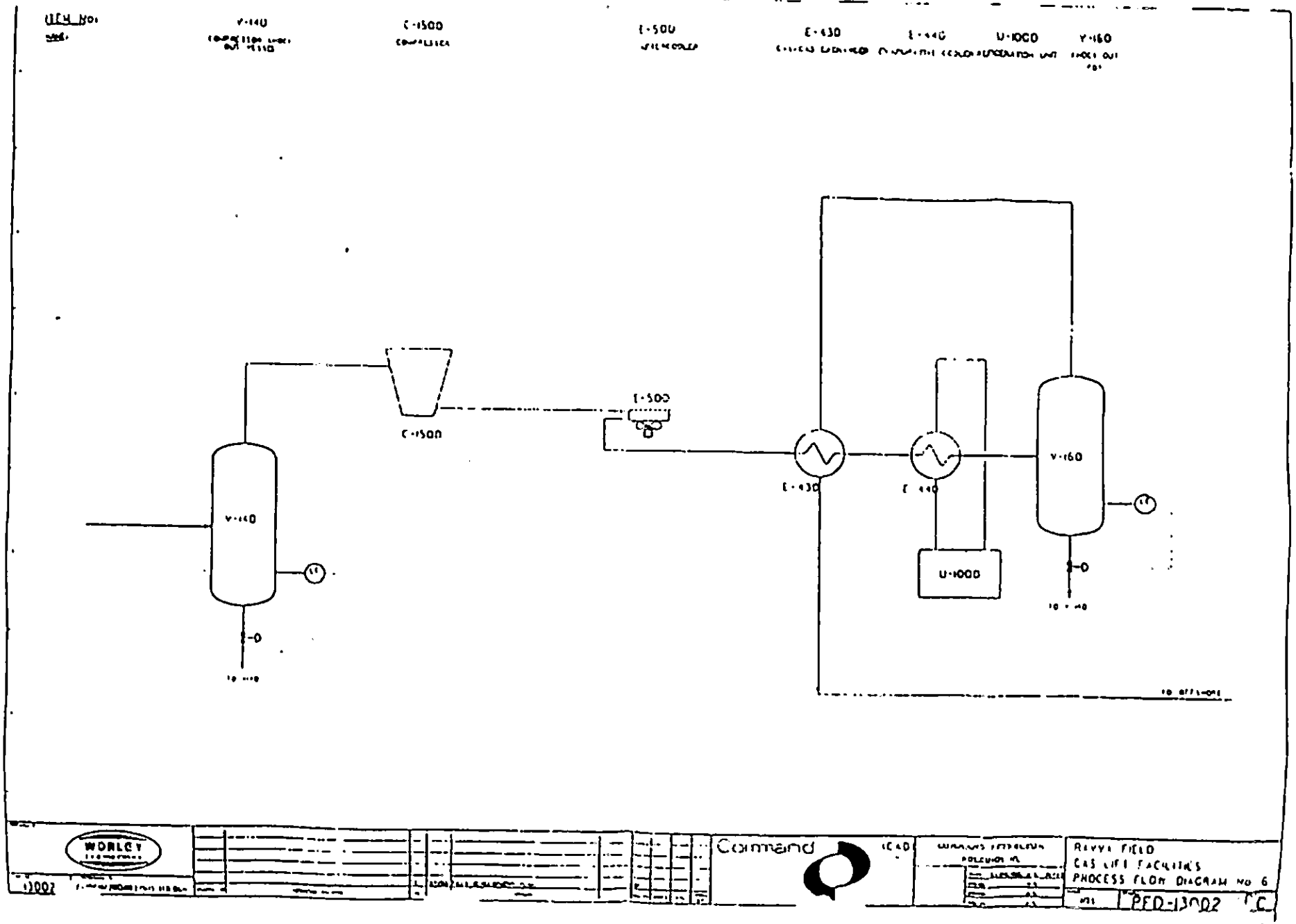
ELEVATION



PLAN

RAVVA FIELD
RAVVA B
COMPUTER MODEL


ITEM No
P-410
X-8400
PRODUCED WATER TREATMENT UNIT
BORE WATER TREATMENT
INJECTION WATER TREATMENT
GROUND WATER TREATMENT
X-8400
P-410
WORLEY
Command
CAD
RAVVA FIELD
WATER INJECTION AND HANDLING
PROCESS FLOW DIAGRAM No 3
PFD 13



WORLEY

Command CAD

REVVA FIELD
GAS LIFT FACILITIES
PROCESS FLOW DIAGRAM No 6

PFD-13002 C

Figure 42

Ravva Field Development Schedule - Phase 1

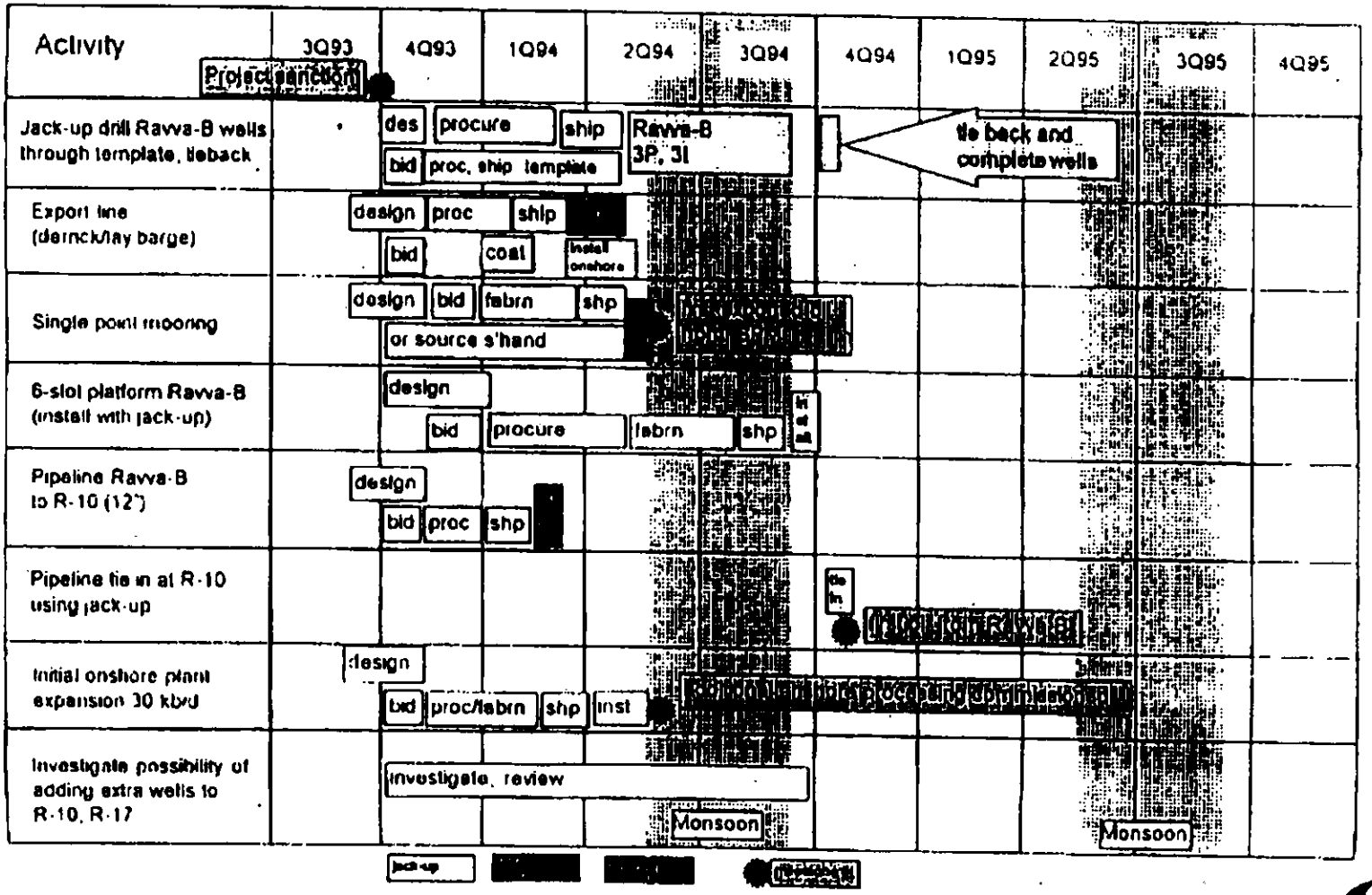


Figure 4-1

Ravva Field Development Schedule - Phase 3

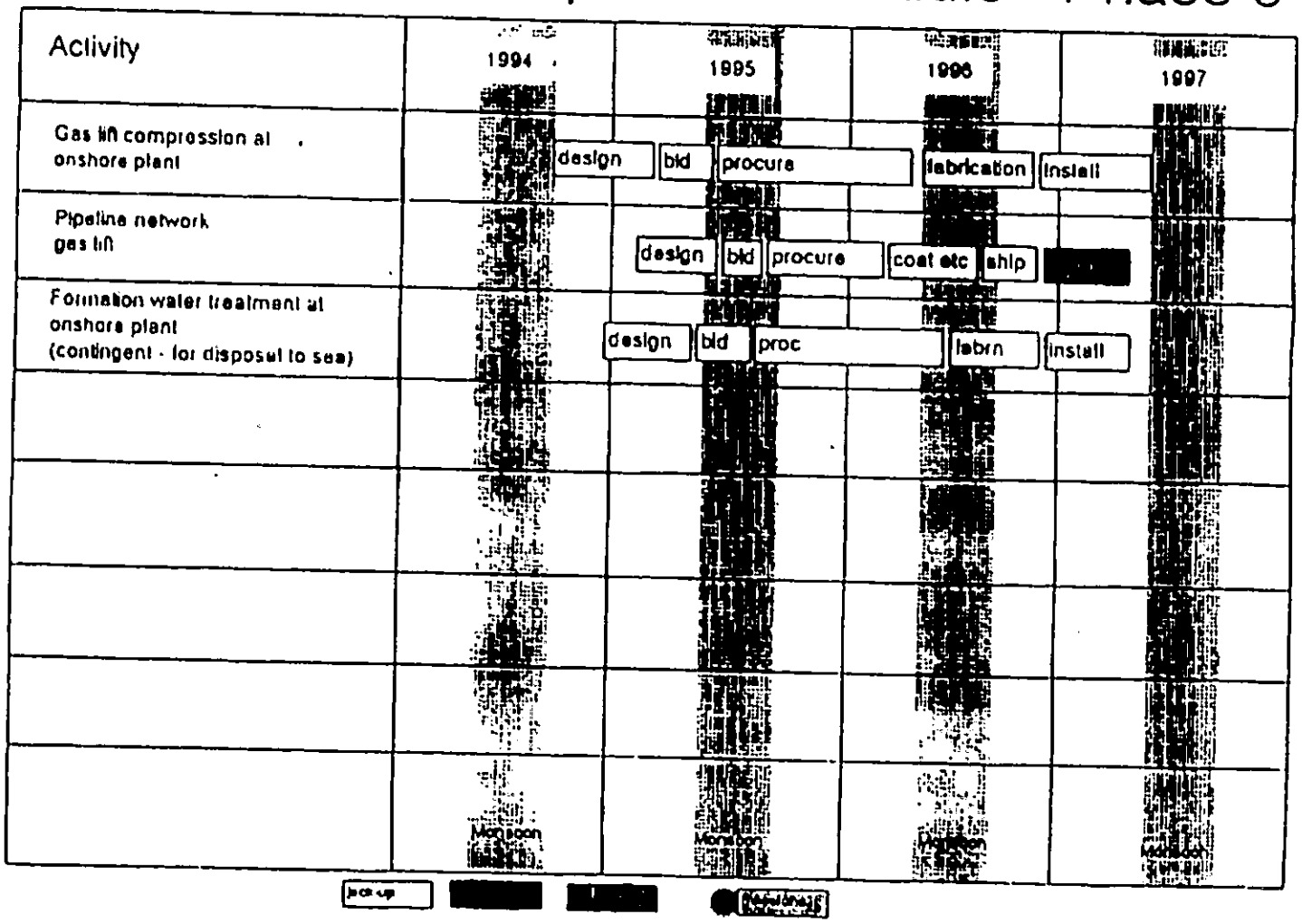


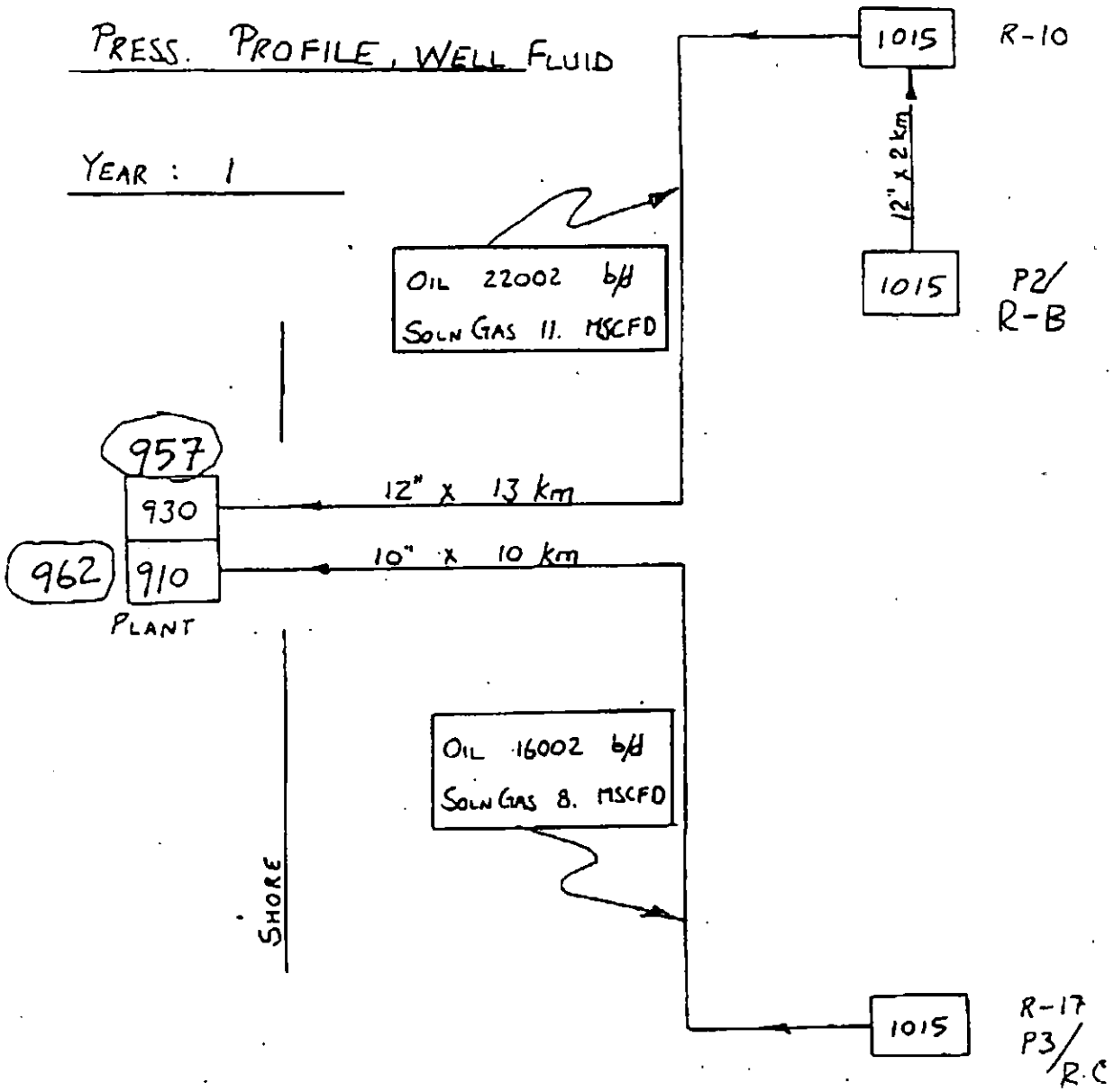
Figure .6

WORLEY ENGINEERING AUSTRALIA

Job No. 20192 Date 18 - 6 - 93
Client
Project RAVVA PRODUCTION SYSTEM
Subject PRESS. DROP CALC
Sheet ___ of ___ By S.Y. Check

PRESS. PROFILE, WELL FLUID

YEAR : 1



NOTES :-

ALL PRESSURES IN PSIA

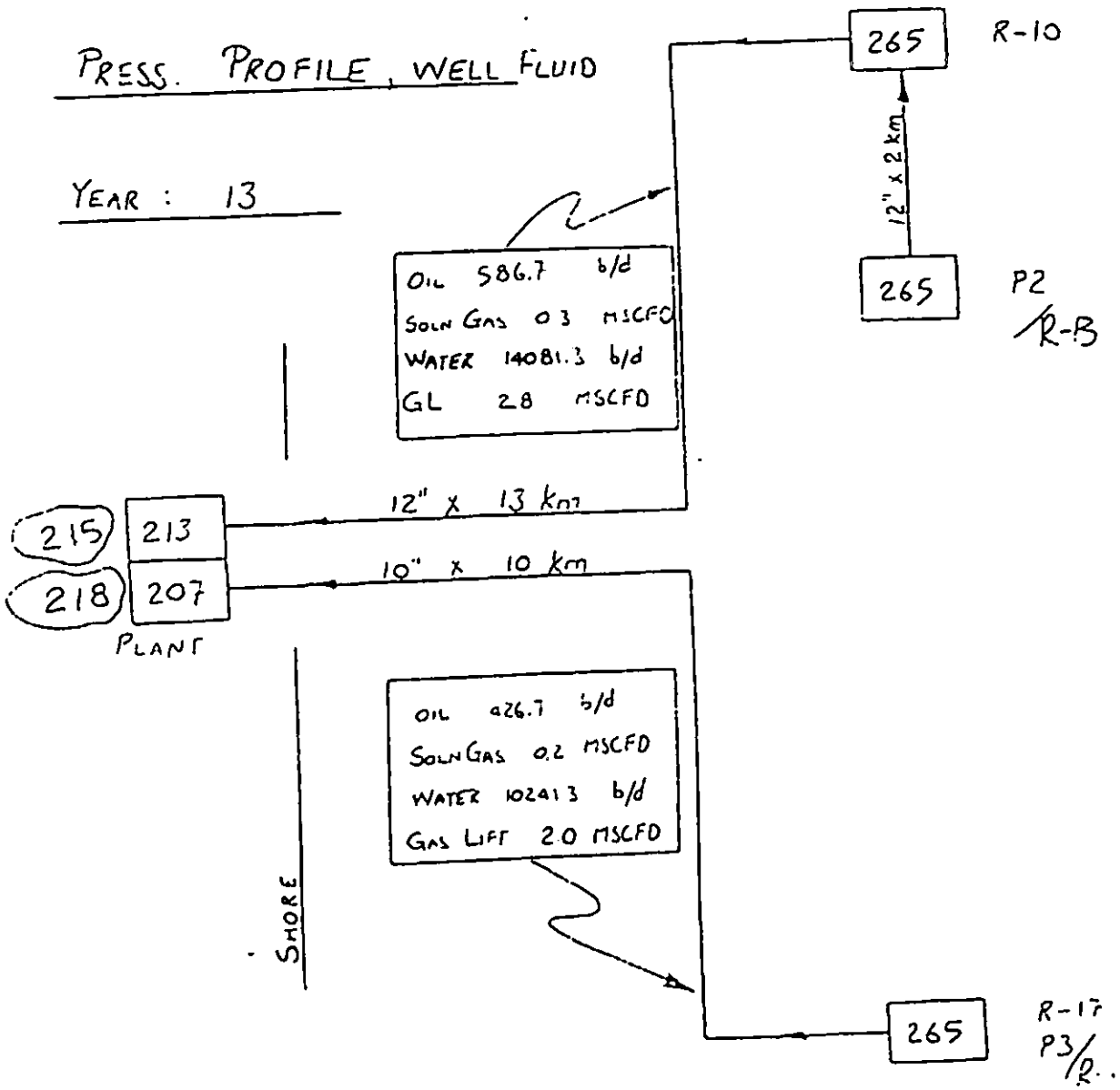
USING ALT'D BEAM DATA

WORLEY ENGINEERING AUSTRALIA

Job No. 20192 Date 18 - 6 - 93
Client
Project RAVVA PRODUCTION SYSTEM
Subject PRESS DROP CALC
Sheet ___ of ___ By S.Y. Check

PRESS. PROFILE, WELL FLUID

YEAR : 13



NOTES:

ALL PRESSURES IN PSIA

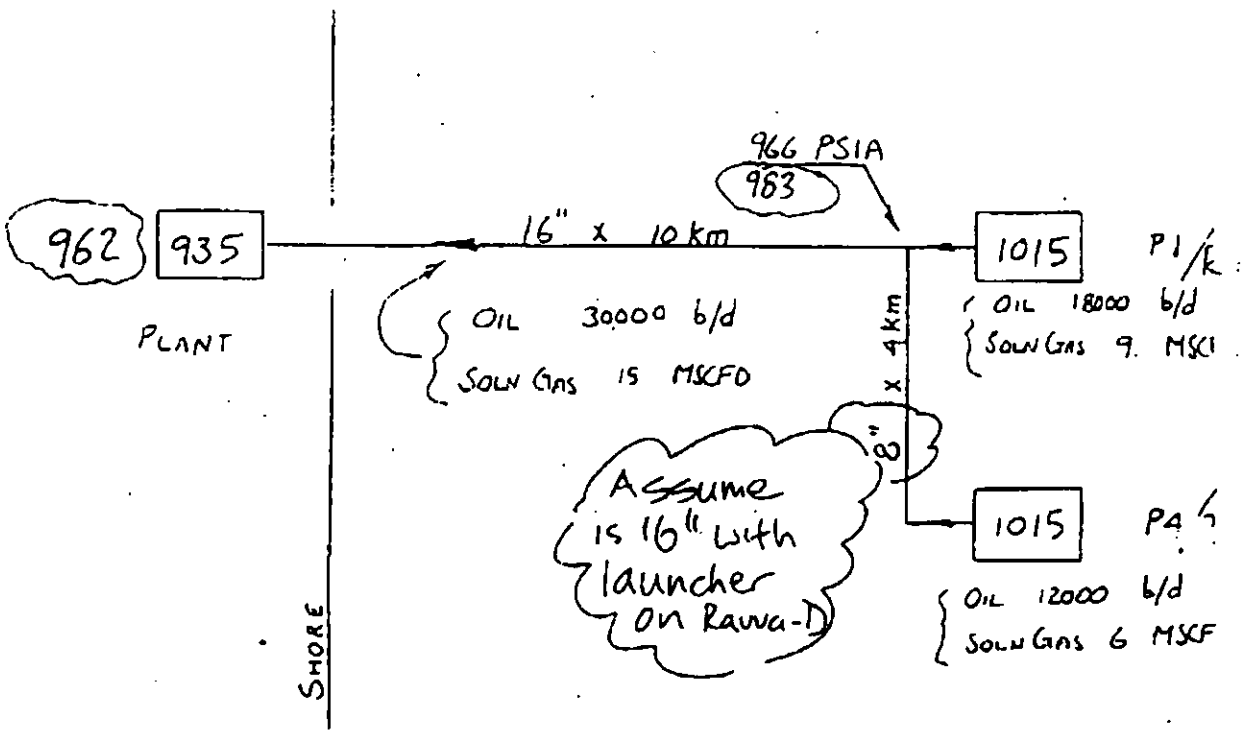
( ) USING ALT'D STREAM DATA

WORLEY ENGINEERING AUSTRALIA

Job No. 20192 Date 18 - 6 - 93
Client
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WELL FLUID (PRESS. PROFILE)

YEAR : 1



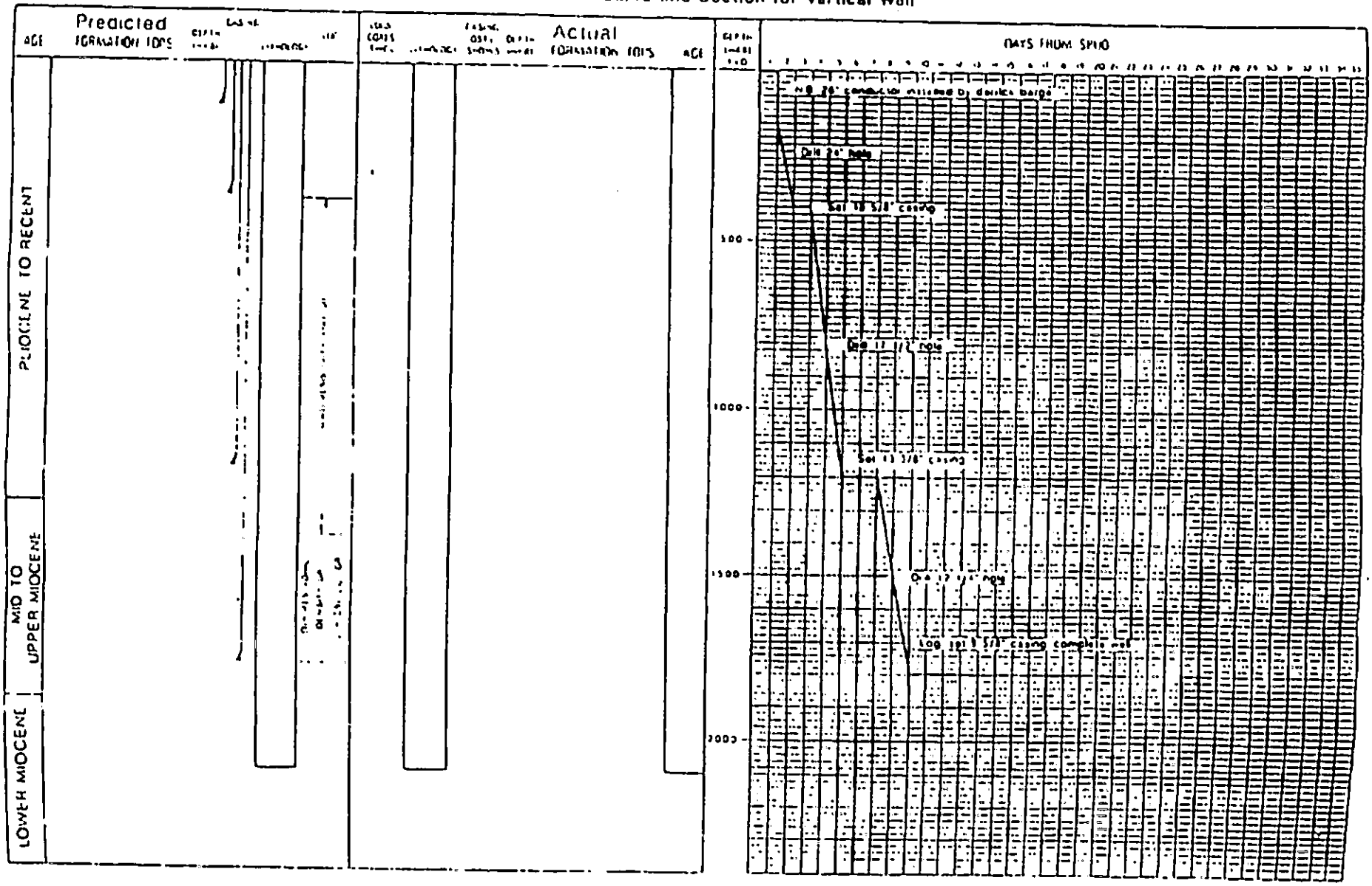
NOTES :

1. ALL PRESSURES IN PSIA
2. USING WELL BORE DATA

RP4P1.501.SIM

Command Petroleum Holdings NL

Provisional Drill Curve and Section for Vertical Well



Ravva Field Development

Anticipated Management Structure
for Madras Operations Office and On-site Supervisor

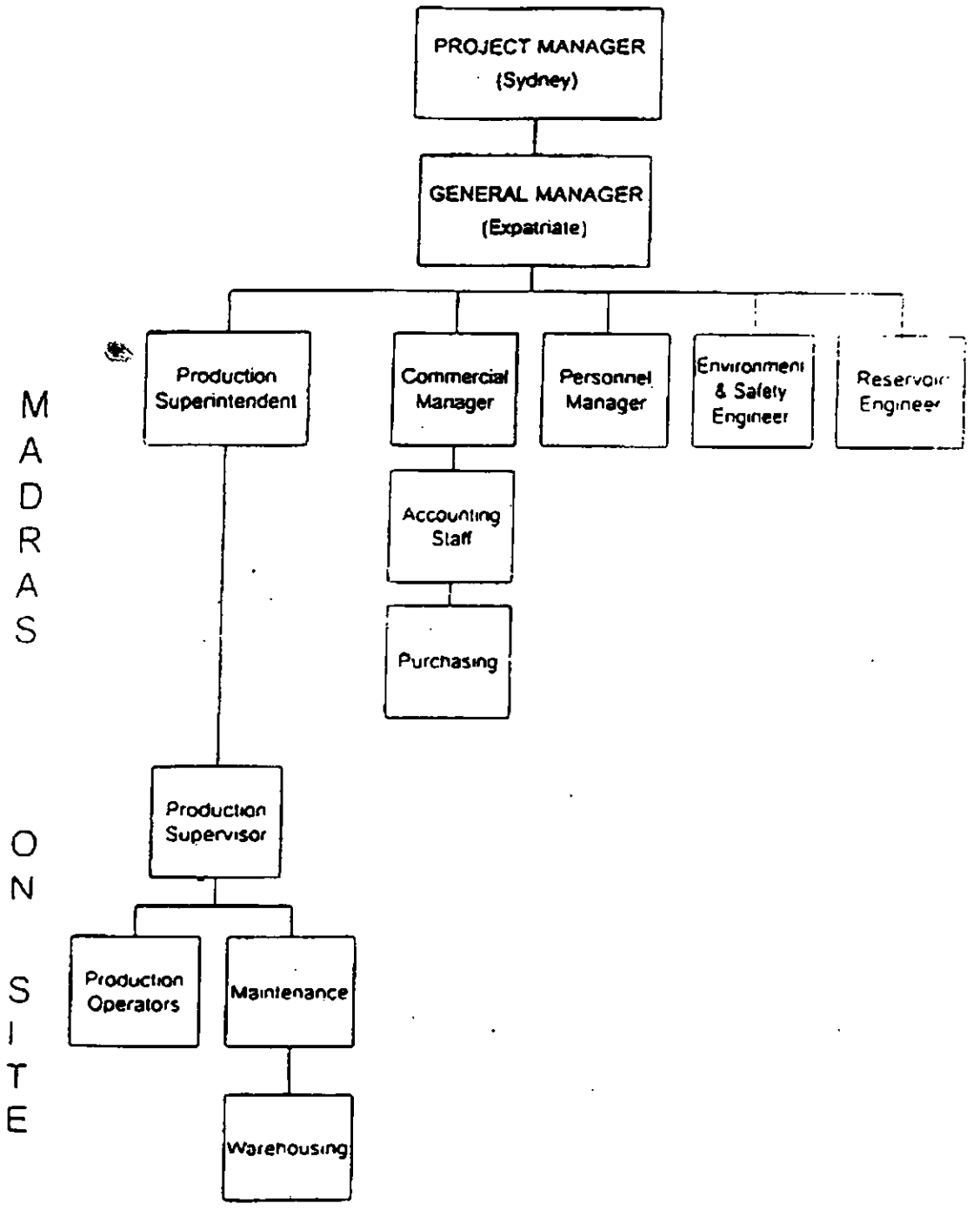


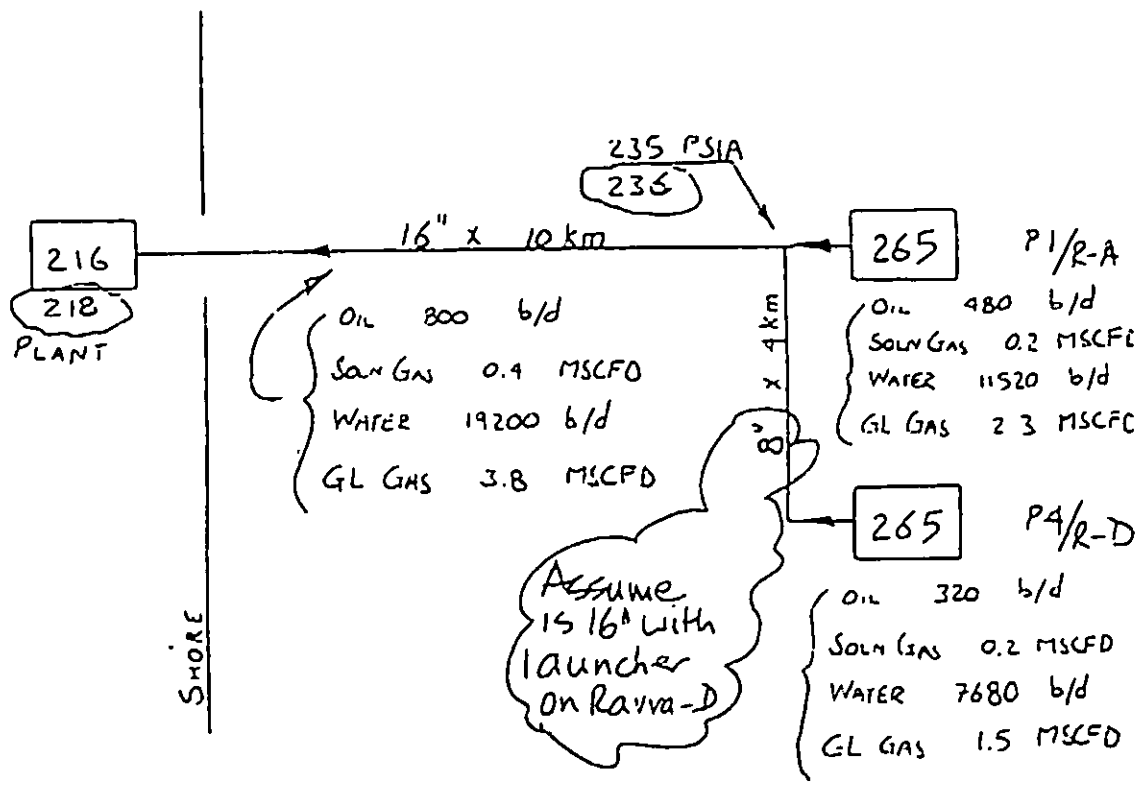
Figure 48

WORLEY ENGINEERING AUSTRALIA

Job No. 20192 Date 18 - 6 - 93
Client
Project RAVVA PRODUCTION SYSTEM
Subject LINE SIZING
Sheet ____ of ____ By SY Check

WELL FLUID (PRESS. PROFILE)

YEAR : 13



NOTES:

ALL PRESSURES IN PSIA

USING ALL SEAM DATA

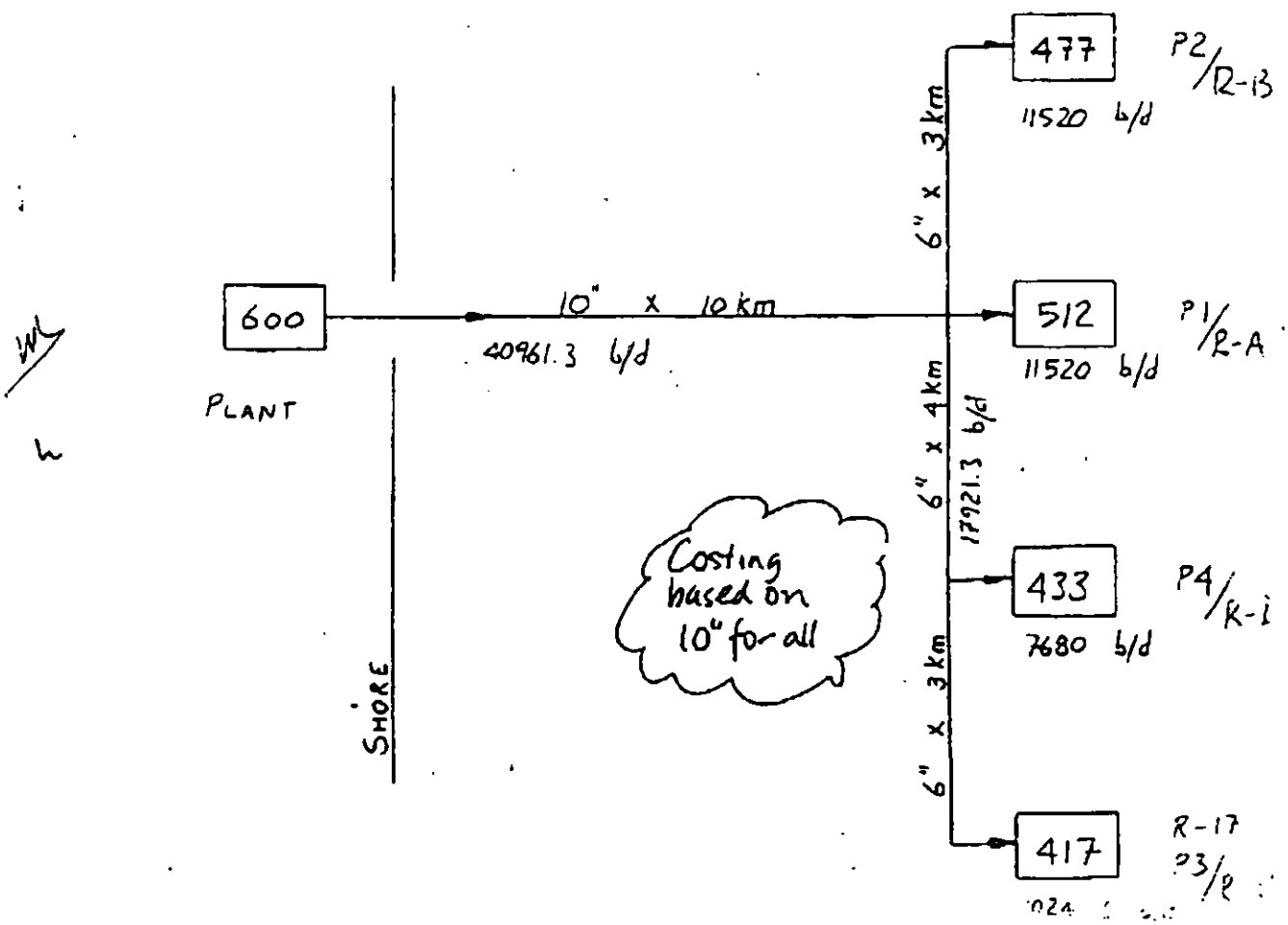
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WORLEY ENGINEERING AUSTRALIA

Job No. 20192 Date 18 - 6 - 93
Client
Project RAVVA PRODUCTION SYSTEM
Subject LINE SIZING
Sheet ____ of ____ By S.Y Check

WATER INJECTION (PRESS. PROFILE)

YEAR : 13



NOTES :

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PIPE LINE CLASS 300#

Command Petroleum Holdings N.L.

A.N.C. 001 685 296

Addendum 1 to

PROPOSED DEVELOPMENT PLAN

for the

RAVVA FIELD

by

COMMAND PETROLEUM HOLDINGS N.L.

for and on behalf of the

VIDEOCON-COMMAND JOINT VENTURE

Report No: 1993/036

August 1993

Addendum to PROPOSED DEVELOPMENT PLAN FOR THE RAVVA FIELD

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5. Non-Associated Gas Processing PFD
6. Overall Project Schedule

SUMMARY

This Addendum to the Proposed Development Plan for the Ravva Field should be read in conjunction with the full version of that Plan which was submitted to the Government of India on 16 July 1993 and discussed in detail with Government representatives on 26-27 July 1993 in New Delhi.

This Addendum highlights a number of modifications to the original Development Plan which have generally been necessitated by the acquisition of new relevant data subsequent to the submission of that Plan and/or the modification of the anticipated production rate of the Ravva Field in order to address concerns that the optimum plateau production rate of 50,000 BOPD quoted in the original Development Plan might prove difficult to achieve.

The main points which this Addendum seeks to clarify include :-

- Although the Videocon-Command Joint Venture continues to be confident that the Ravva Field has the capability to achieve a production plateau of 50,000 BOPD, a "firm" plateau rate of 40,000 BOPD has been identified and has been combined with a revised project schedule to provide a revised production forecast for the project. Although the changes to the plateau rate and to the early production schedule diminish the commerciality of the project and delay the onset of project profitability, they do not destroy the overall commerciality of the project.

- The Videocon-Command Joint Venture is confident that the modified production plateau rate of 40,000 BOPD will be achievable within the context of the Development Plan as amended, and this confidence is evidenced by the fact that the Joint Venture is prepared to commit to achieving that rate by giving a guarantee that additional capital expenditure up to a maximum of US$12 million would be met by the Joint Venture and such additional costs, to the extent that they are in excess of the budgeted "firm" costs, would not be recoverable from Cost Oil under the PSC.

- Recently acquired data has allowed the Videocon-Command Joint Venture to firm up its plans to develop the associated and non-associated gas reserves at the Ravva Field. This confirmation is an important new aspect to the Videocon-Command Joint Venture's application to develop the Ravva Field and one which the Joint Venture feels is very positive.

- A revised project schedule has been prepared reflecting possible slippage of award date, prolonged monsoonal period and inclusion of the gas development concept into the project's timing.

- An important point in this Addendum is the Videocon-Command Joint Venture's commitment to expend US$19.3 million exploring and appraising oil and gas accumulations in the Ravva Field licence beyond the confines of R10 and R17 Blocks, which will be the main initial focus of the development. This

exploration and appraisal programme will be conducted in a timely manner and the Videocon-Command Joint Venture expects it to result in the development of further oil and gas reserves in the licence area.

- There has been a modification to the anticipated cost of the project which relates largely to the incorporation of a gas development scheme and the renewed emphasis on exploration and appraisal beyond the R10 and R17 Blocks. It is now anticipated that the development of the Ravva Field will cost US$225.99 million, exclusive of import duty but including field abandonment costs.

This Addendum and the undertakings and commitments which it contains are based upon information made available to Command prior to 18 August 1993 and if the subsequent acquisition of additional data significantly and adversely alters the understanding outlined in this Addendum, then the Videocon-Command Joint Venture would need to review the undertakings referred to herein. At this point in time the Joint Venture believes that the work which it has undertaken to date is as thorough and as reliable as the available data set allows, and therefore it is not considered likely that additional information would cause any major revision of the Development Plan.

Addendum TO
PROPOSED DEVELOPMENT PLAN
FOR THE
RAVVA FIELD

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5. Non-Associated Gas Processing PFD
6. Overall Project Schedule

1 INTRODUCTION

On 16 July 1993 the Videocon-Command Joint Venture submitted to the Government of India a report entitled "Proposed Development Plan for the Ravva Field". On 26-27 July 1993 the Joint Venture presented and discussed details of this Development Plan with representatives of the Indian Government and ONGC. Subsequently the Indian Government requested that the Videocon-Command Joint Venture clarifies certain aspects of the Development Plan and provides certain undertakings with regard to both the development of the R10 and R17 Blocks and additional exploration and appraisal in other parts of the Ravva Licence. This Addendum provides the clarifications and confirmations sought by the Government.

In response to the Government's request that the Joint Venture nominate and commit to a firm production profile, this Addendum presents a modified production forecast based on a plateau production rate of 40,000 BOPD which the Videocon-Command Joint Venture is confident of, and committed to, achieving.

Subsequent to the submission of the original Development Plan, further information has become available with regard to the possibility of marketing gas from the Ravva Field. This information has allowed the Joint Venture to present in this Addendum details of its plan for processing and disposing of produced associated and non-associated gas.

In order to accommodate the possibility that the licence award will occur later than the originally anticipated date of early October 1993 and the possibility that the monsoon season may be more prolonged than was originally assumed, this Addendum presents a revised project schedule and cost estimates which take into account such possibilities as well as increases to the overall project duration.

The Joint Venture's commitment to further appraisal and exploration drilling within the Ravva licence area is reaffirmed and further clarification is provided.

Further to the Government's request, the decisions regarding onshore/offshore processing and storage, as well as alternative mooring systems, are also reviewed.

This document is provided as an Addendum to the original Development Plan and should be regarded in this context.

2 RESERVES AND PRODUCTION, R10 AND R17 BLOCKS

The Videocon-Command Joint Venture will develop and produce the oil and gas reserves in accordance with the best international practices of facilities design, drilling and completion, reservoir management and field operations, so as to maximise the economic recovery of oil and gas. All operations would be subject to Joint Venture and, where appropriate, Government approvals.

In particular, neither oil nor gas will be produced at a rate which would be detrimental to ultimate recovery, nor will the safety or continuity of operations be jeopardised. Oil and gas will be produced in a manner and at rates which can be achieved safely and which maximise the commercial recovery of hydrocarbons from the licence area. All activities will be technically and commercially justified to, and approved by, the Joint Venture.

2.1 Oil-in-Place and Recoverable Reserves

It was estimated in the earlier Development Plan that, for the combined R10 and R17 Blocks, there is a 90 percent chance of exceeding 80.5 MMBBL reserves ("Proven") and a 50 percent chance of exceeding 101.0 MMBBL reserves ("Proven-plus-Probable"). There is no reason to revise those estimates at this time. Given the uncertainties in the basic data affecting the oil-in-place and reserves estimations, a probabilistic approach was adopted to estimate these combined figures, with no specific apportionment between the Blocks. For the purposes of quantifying oil-in-place and recoverable reserves by Block for the production forecasts presented in this Addendum, a recovery factor of 50% (applicable to each Block) and an oil-in-place split of 58% to Block R10 and 42% to Block R17 have been assumed. Thus, for the present purposes only, reserves of the Ravva field are as follows :-

	Blocks R10+R17 (100%)	*Block R10 (58%)*	*Block R17 (42%)*
Proven Oil-in-Place, MMBBL (MMT)	161.0 (21.8)	93.4 (12.6)	67.6 (9.2)
Proven Reserves, MMBBL (MMT)	80.5 (10.9)	46.7 (6.3)	33.8 (4.6)
Proven-plus-Probable Oil-in-Place, MMBBL (MMT)	202.0 (27.2)	117.2 (15.8)	84.8 (11.4)
Proven-plus-Probable Reserves, MMBBL (MMT)	101.0 (13.6)	58.6 (7.9)	42.4 (5.7)

2.2 "Firm" Production Forecast

After due consideration of all available information, "firm" production forecasts have been prepared based on a plateau production rate of 40,000 BOPD At

this rate, annual production is almost .15 MMBBL (2 MMT), equivalent to less than 15% of Proven-plus-Probable oil-in-place. The plateau duration is dependent largely on the ultimate reserves and on the number of wells.

The forecasts assume the drilling and completion over an 18-month period of 19 new development wells, 11 of which are in the R10 Block and will probably be dually completed. Some wells will be brought on stream initially as producers and later converted to water injection wells to maximise oil recovery. Notionally, an average of 14 production wells (including the 4 wells already completed) and 9 injection wells is anticipated. Based on the results of an ongoing reservoir monitoring and management programme, options to optimise recovery will be continuously identified throughout field life. The Joint Venture will have the ability to access additional reserves in the R10 and R17 Blocks in several ways: wells may be re-drilled during field life, five extra wells can be drilled from spare drilling slots on the 4 planned platforms, or extra platforms can be installed at low cost.

Individual well rates are restricted to below 4,000 BFPD at all times. The field production forecasts are derived in a similar manner to that described in the Development Plan, by compounding individual well oil and water production profiles as the wells are drilled.

The total assumed rate from wells R-10, R-17, R-34 and R-35, which will all be available for production by September 1993, has been restricted to 3,000 BOPD in the absence of firm productivity information.

"Firm" production forecasts for both the Proven and Proven-plus-Probable reserves levels are presented in Tables 1 and 2 and Figures 1 and 2. These Tables and Figures identify production from the R10 and R17 Blocks separately, as well as the timing and magnitude of water injection.

Core and reservoir fluid data are essential for the reliable prediction of waterflood efficiency, timing of water breakthrough, rapidity of water production increase and ultimate reserves, but unfortunately this information is not presently available. Therefore, it is not possible to be certain about any production forecast in the long term unless the forecast is extremely conservative.

From consideration of the available data, it is estimated that an average production rate in excess of 40,000 BOPD can be sustained as follows:

- a 50% chance of sustaining the rate over a 3-year period within 6 years of licence award,
- a 90% chance of sustaining the rate over an 18-month period within 4.5 years of licence award.

- a 95% chance of sustaining the rate over a 6-month period within 3 years of licence award.

2.3 Optimum Production Forecast

The optimum production forecast is that which the Videocon-Command Joint Venture believes may be achieved if production data acquired during the early phase of development accords with expectations derived from currently available information. The optimum production forecast coincides with the forecast proposed in the previously submitted Development Plan, with plateau production of 50,000 BOPD deferred to accommodate a changed development schedule as outlined in Section 4 of this Addendum. The forecast assumes a higher individual well productivity than does the "firm" forecast, some 6,000 BOPD per well, dropping to 4,000 BFPD at the onset of water production. As for the "firm" production forecast, the total rate from existing wells is restricted to 3,000 BOPD.

The production forecast for the Proven-plus-Probable reserves level is presented in Table 3 and Figure 3.

2.4 Well Deliverability

ONGC's analyses of production tests on wells R-10, R-12, R-17 and R-27 indicate that an average Ideal Productivity Index (PI) for the tested intervals would be some 200 BOPD/psi. The Videocon-Command Joint Venture broadly agrees with these analyses and conclusions. All tests exhibited high apparent wellbore skin damage, such that the average Actual PI on test was some 25 BOPD/psi. Some of the apparent damage would have been due to free gas breakout in the near wellbore region and some would have been due to the test tool configuration.

Some wellbore damage may be unavoidable, but the Videocon-Command Joint Venture believes that a significant improvement can be achieved by modifying drilling, perforating, completion and testing procedures and that PIs above 100 BOPD/psi will be obtained. Even so, in forecasting well productivity, the Joint Venture has assumed an average PI for each new well of only 30 BOPD/psi, which, given that most of the wells will be dually completed, corresponds to an average PI for each completed interval of only 20 BOPD/psi.

Applying the Vogel IPR to each well and thereby further reducing the PI to account for free gas breakout near the wellbore under producing conditions, each well is still able to achieve 6,000 BOPD with a drawdown of only 300 psi, which is less than 15 percent of reservoir pressure and which is believed to be a conservative limit to place on drawdown at this stage.

The proposed changes to operational practices will not only increase well productivity, but will reduce the tendency of wells to produce sand. High skin

damage causes much increased pressure differentials near the wellbore, while low perforation density causes higher localised flow velocities, both of which increase the tendency to produce sand.

Command has operated wells where there was considered to be a danger of sand production and is acutely aware of the need for careful programming of all early-life operations and for the careful monitoring of well performance, including regular and frequent spin-outs, inspection of separators and tagging of well bottom to look for fill-up. If evaluation proves that gravel-packing is necessary, the Videocon-Command Joint Venture believes the gravel-pack will not cause a reduction in useable well production capacity, since the same or greater pressure drop in the reservoir will be allowed and the effect of the gravel-pack will be seen in the lower flowing wellhead pressure. As the initial flowing wellhead pressure should be above 600 psi, a reduction of several tens of psi can be easily accommodated.

2.5 Platform and Well Locations

Precise location of platforms and wells cannot be determined until after seismic reprocessing and interpretation and after reservoir simulation has been used to optimise the overall development plan. Indicative platform and well locations were given in the report "Ravva Field, Technical Review", dated June 1993. These indicative locations are still valid and are described as follows:

Platform R-A (R10 Block)	4.5km SW of R-10	3 Prod / 2 Inj
Platform R-B (R10 Block)	2.0km SW of R-10	3 Prod / 3 Inj
Platform R-C (R17 Block)	Adjacent to R-17	2 Prod / 2 Inj
Platform R-D (R17 Block)	3.0 km N of R-17	2 Prod / 2 Inj

Facilities and costs planned for development of the R10 and R17 Blocks are described in Section 5 of this document.

2.6 Production Rate Undertaking

The Videocon-Command Joint Venture is able to express its confidence in the field's production capability by committing to achieve the capability of producing oil at a rate averaging in excess of 40,000 BOPD over a six month period within a period of 36 months from formal licence award.

The Videocon-Command Joint Venture will incur additional expenditure to achieve the aforementioned production target up to an amount of US$12 million on the R10 and R17 Blocks, and such expenditure will not be recoverable under the PSC to the extent that the resultant total expenditure exceeds the project budget.

These undertakings and guarantees are based upon information made available to Command prior to 18 August 1993 relating, in particular, to the character of the reservoir rock and fluids in the Ravva Field and to the offshore construction environment. In addition, certain other technical assumptions have had to be made in the absence of reliable technical data. In some cases, the relevant data have not been collected while, in other cases, the data have not been made available to the Videocon-Command Joint Venture. The main assumptions which have been made relate to :-

- The distribution of net pay within the Ravva Field.
- The nature of the reservoir rock and fluid properties.
- The nature of the source of injection water, including the assumption that that water will be compatible with the formation water and reservoir rock so that it will be suitable for use in water injection.

Major assumptions on the timing side are that :-

- The Joint Venture, including ONGC, which develops the Ravva Field will approve the Videocon-Command Development Plan outlined herein and allow the operator to implement that concept in a timely manner.
- The tendering process for the field development will be according to standard international industry practice and not subject to undue delays.

In the event that subsequent access to, or acquisition of, further data significantly and adversely alters the understanding outlined in this Addendum and in the full Development Plan presented in July 1993, then there would be a need for the Videocon-Command Joint Venture to review the undertakings referred to herein in light of the new data. It should, however, be emphasised that the Videocon-Command Joint Venture believes that the work which it has undertaken to date is as thorough and as reliable as the available data set allows and, therefore, it is not presently aware of any reason why the additional information that may be viewed and/or collected should not accord with the information already reviewed. Thus there is no reason to believe that it will not be possible to meet the undertakings provided in this Addendum.

3 GAS UTILISATION

3.1 General

The Videocon-Command Joint Venture intends to sell as much gas as possible from the Ravva licence area, and thereby minimise or eliminate the amount of gas to be flared.

Further, it is the intention of the Joint Venture to install an LPG plant if sufficient gas reserves and LPG yield can be established to warrant the additional investment and if market conditions will allow a reasonable return on the investment.

While the Joint Venture will be seeking to sell all net gas produced, it will also review the feasibility of using the gas to generate electricity for sale into the local grid network.

3.2 Schedule

Section 4 of this Addendum describes in detail the proposed project schedule to which the Joint Venture is committed, and this schedule includes a proposal for the utilisation of both associated and non-associated gas. In summary, it is intended to :-

- Commence design and procurement of a plant to process associated gas immediately upon contract award with a view to having this plant commissioned by the second quarter of 1995, which is before maximum oil production rates will be achieved.

- Prove up non-associated gas reserves by drilling appraisal well(s) in the fourth quarter of 1994. If successful, non-associated gas will be available for sale by the third quarter of 1995.

- Commence sales of up to 1.5 million cubic metres per day of gas (combined associated and non-associated) in the third quarter of 1995. Actual sales volume will be determined based on appraisal drilling results and market negotiations.

3.3 Gas Treatment Facilities

Process flow diagrams for the two plants required to treat the associated and non-associated gas streams are included as Figures 4 and 5. For the present purposes we have assumed a plant discharge pressure of 800 psig. A requirement for a higher delivery pressure may require additional compression but would not otherwise significantly alter the proposal.

3.3.1 Associated Gas

Gas received from the slug receiver and production separator will be cooled to separate all liquids prior to being compressed to 800 psig for discharge into the sales line.

The sales line will be a 10 inch diameter line connecting the gas plant with the trunk line located 11 kilometres away. Inlet pressure will be 800 psig and outlet being 720 psig, and the capacity of the line will be 1.5 million cubic metres per day.

It is understood that Gas Authority of India Limited ("GAIL") may have plans to install this spur line before end 1994.

3.3.2 Non-Associated Gas

Non-associated gas will be brought to shore via a separate 10 inch diameter pipeline. Condensate will be separated in a slug catcher, stabilised and transferred to the crude oil storage tanks. Later in the life of the field the mix of condensate and oil may be such that the product RVP exceeds the recommended limit. If this occurs it may be necessary to add facilities to stabilise the condensate.

After separating out condensate, the gas will be dried in a glycol contactor and cooled to remove any remaining liquids before entering the gas sales line at a pressure of 800 psig.

4 PROJECT SCHEDULE

A revised project schedule has been prepared which reflects the following changes :-

- a "Project Sanction" date of 1 November 1993 (previously 1 October 1993);
- an extended monsoon season from 1 May through 30 September (previously 15 May through 15 September), during which time it will not be possible to utilise an offshore construction barge;
- incorporation of appraisal/exploratory drilling; and
- inclusion of the gas utilisation sector of the project.

These modifications have resulted in changes to the achievement of certain milestones as follows :-

	Previous	*Revised*
Project sanction	1/10/1993	1/11/1993
First oil shipped through SPM	1/6/1994	1/11/1994
First oil from Ravva-B	1/11/1994	15/12/1994
Maximum production rates	15/6/1995	1/1/1996
First gas sales	-	1/5/1995

The schedule presented herein (see Figure 6) is one to which the Joint Venture is prepared to commit to provided contract award occurs in October and no additional information is received which significantly affects the manner in which the field should be developed.

The changes to the project timing, in particular to the timing of installation of the offshore loading system and to the timing of development well drilling, have resulted in the deferral of peak production rates from mid 1995 to early 1996. Furthermore, as indicated in Section 2, the production forecasts have assumed no capacity to increase production beyond 3,000 BOPD from the four wells completed to date.

The changes to the schedule thus result directly in a deferral of project revenue which diminishes the commerciality of the project. Further, the inclusion of a significant exploration/appraisal drilling programme and expansion of the firm project scope have led to increased capital costs as detailed in Section 5. In this context, an important point to note is that, according to the production forecasts, project schedule and total costs scenario presented in this Addendum, it is anticipated that ONGC will be required to contribute approximately US$15 million towards the Ravva development from its own funds.

5 PROJECT COSTS

Total project costs have increased as a result of :-

- inclusion of an appraisal/exploration drilling programme ($19.31 million);
- inclusion of plant to treat associated gas ($8.65 million); and
- addition of non-associated gas development project ($14.57 million)

In addition there have been minor changes in costs resulting from the modifications to the schedule.

Total costs, including abandonment, in US$ million are summarised as follows :-

	Cost	*Import Duty*	*Total*
Development of the R10 and R17 Blocks including sale of associated gas	166.42	25.56	191.98
Appraisal and Exploratory drilling programme	19.31	2.09	21.40
Development of non-associated gas	14.57	2.32	16.89
Provision of gas lift facilities (anticipated in Year 6 or 7 of the project)	7.69	1.42	9.11
Abandonment	18.00	0.00	18.00
TOTAL	225.99	31.39	257.38

Details of cost estimates are contained in Table 4.

6 APPRAISAL PROGRAMME

6.1 Geological and Geophysical

The Videocon-Command Joint Venture is committed to fully appraising and developing the potential hydrocarbon reserves in the Ravva licence area.

To achieve this, initial work would be designed to improve the data set. The 3D and 2D data sets will be reprocessed because it is believed that recent advances in processing techniques should allow the data quality to be improved. Particular attention will be paid to dip filtering, deconvolution and migration. Provided that tapes and supporting data can be obtained immediately upon award of the licence, reprocessing will be completed within six months.

Interpretation of the existing seismic data set, as well as the geological and engineering data, will commence as soon as the data are received and will continue on the reprocessed data.

6.2 Fluid and Core Sampling

Fluid samples will be collected from producing wells immediately after award of the licence and will be analysed to help in the design of facilities.

Available cores will be inspected, and sampled and analysed where appropriate. Additional core will be collected on new wells. Analyses will focus on, among other things, porosity, permeability, formation factor, capillary pressure and relative permeabilities.

6.3 Drilling

Several hydrocarbon pools intersected by existing wells will be appraised, and new exploration drilling will be undertaken. Drilling is anticipated to start approximately 12 months after licence award.

Prime candidates for early appraisal interpretation and drilling include Blocks 1, 7, 9, 22 and 23 for gas, Block R13 for gas and oil, Ravva-5 for oil and Block 2.8 for oil and gas.

Potential exploration targets include areas east of Ravva-17, west of Ravva-27 and east of Ravva-10.

Three wells are planned for each of the first and last quarters of the second licence year.

Subsequent appraisal and exploration drilling activity will be dictated by the results of the initial 6-well drilling programme and the geophysical reinterpretation.

7 JUSTIFICATION FOR USE OF ONSHORE FACILITIES

Several options were considered for the development of the Ravva Field. All options share a common method of transporting oil from the field, i.e., offshore tanker loading.

- Free flow of well fluids to shore with onshore processing and storage.
- Free flow of well fluids ashore with onshore processing and offshore storage in a permanently moored tanker.
- Processing of fluids offshore on a fixed production platform with onshore storage.
- Processing of fluids offshore on a fixed production platform with offshore storage in a permanently moored tanker.
- Floating production and storage on a FPSO.
- Use of a jack-up rig as a production platform. The costs for this option assume the rig is contracted on a "bare-boat" basis at a rate of US$10,000 per day for a period of 10 years.

Table 5 summarises the capital and operating costs of these alternatives.

Examination of this table reveals that the use of onshore storage and processing will incur lower capital and operating costs. In addition this option has a number of other benefits :-

- Safety - no personnel will need to be accommodated offshore.
- Environmental protection - no processing is performed offshore.
- Flexibility - offshore production facilities are designed for specific production rates. Any additional capacity required as a result of successful exploration/ appraisal drilling could be accommodated at significantly less cost using onshore facilities rather than offshore facilities.
- An offshore production facility would make the existing onshore plant redundant, whereas an onshore development will build on and add to these facilities.
- Onshore facilities will be quicker to fabricate and install than the comparable offshore facilities, resulting in earlier achievement of maximum production rates.
- If offshore process facilities are utilised it may not be economic to sell associated gas. In this case the gas would have to be flared.

8 MOORING SYSTEM REVIEW

The Development Plan for the Ravva field specified the use of a Single Point Mooring system for the purposes of loading tankers. It is the Videocon-Command Joint Venture's intention to undertake a detailed evaluation of alternative mooring systems if it is awarded the licence.

A preliminary comparison of the proposed SPM type mooring and a multi-point spread mooring has already been completed. This comparison has revealed that a spread mooring could result in capital cost savings of at least $3.5 million but that it would result in downtime costing some $3 million over a ten year period. This cost does not include the cost of having to shut the field in should the mooring be unusable for a few days and the onshore storage facilities be fully utilised.

In view of the potential for downtime to be incurred, and the possibility for field shutins, a more detailed analysis needs to be made before a commitment is made to one system or the other. Consequently, the project cost estimates continue to allow for the cost of the SPM type mooring.

9 CONCLUSIONS

The main overall conclusion contained in this Addendum is that :-

- although the inclusion of firm plans to develop the gas reserves at Ravva, and the modification of the production profile, have respectively positive and negative impacts upon the commerciality of the Ravva development as proposed by the Videocon-Command Joint Venture, the overall commercial attraction of that development is maintained, so that there has been no necessity for the Videocon-Command Joint Venture to modify in any fundamental way its desire to develop the Ravva Field.

TABLES

RAVVA FIELD, OIL/GAS/WATER PRODUCTION, WATER INJECTION FORECAST

40,000 BOPD PLATEAU, 80 MMBBL RESERVES

PERIOD	R10 BLOCK OIL PRODUCTION RATE (BOPD)	R17 BLOCK OIL PRODUCTION RATE (BOPD)	R10 & R17 BLOCKS OIL PRODUCTION RATE (BOPD)	R10 BLOCK CUMULATIVE OIL PRODUCTION (MMBBL)	R17 BLOCK CUMULATIVE OIL PRODUCTION (MMBBL)	R10 & R17 BLOCKS CUM OIL PRODUCTION (MMBBL)	PRODUCING WATER CUT (%)	WATER INJECTION RATE (BWPD)	CUMULATIVE WATER INJECTION (MMBBL)	ASSOCIATED GAS PRODUCTION RATE (MMm3/D)	FREE GAS PRODUCTION RATE (MMm3/D)	TOTAL GAS SALES RATE, (MMm3/D)
EARLY YEARS BY QUARTER -												
1Q03	0	0	0	0.00	0.00	0.00	n.a.	0	0.00	0.000	0.000	0.000
2Q03	0	3,000	3,000	0.00	0.27	0.27	0.0%	0	0.00	0.036	0.000	0.000
3Q03	0	3,000	3,000	0.00	0.55	0.55	0.0%	0	0.00	0.036	0.000	0.000
4Q03	1,500	1,500	3,000	0.14	0.68	0.82	0.0%	0	0.00	0.036	0.000	0.000
1Q04	1,500	1,500	3,000	0.27	0.82	1.10	0.0%	0	0.00	0.036	0.000	0.000
2Q04	1,500	1,500	3,000	0.41	0.68	1.37	0.0%	0	0.00	0.036	0.000	0.000
3Q04	1,500	1,500	3,000	0.55	1.10	1.64	0.0%	0	0.00	0.036	0.000	0.000
4Q04	4,053	1,500	5,553	0.82	1.23	2.15	0.0%	0	0.00	0.071	0.000	0.000
1Q05	12,987	1,500	14,487	2.10	1.37	3.47	0.0%	0	0.00	0.185	0.000	0.000
2Q05	14,263	8,158	22,421	3.40	2.20	5.61	0.0%	20,000	1.63	0.298	0.000	0.000
3Q05	20,845	8,158	29,003	5.28	3.04	8.33	0.0%	36,000	3.29	0.380	0.470	0.700
4Q05	23,197	8,158	32,355	7.40	3.88	11.28	0.0%	42,805	6.20	0.412	0.438	0.700
FULL FORECAST BY YEAR -												
1993	375	1,875	2,250	0.14	0.68	0.82	0.0%	0	0.00	0.028	0.000	0.000
1994	2,136	1,500	3,636	0.92	1.23	2.15	0.0%	0	0.00	0.048	0.000	0.000
1995	17,773	7,243	25,017	7.40	3.88	11.28	0.0%	25,201	9.20	0.318	0.227	0.350
1996	23,184	16,816	40,000	15.67	10.01	25.68	0.0%	52,000	28.18	0.510	0.340	0.700
1997	23,184	16,816	40,000	24.33	16.15	40.48	0.0%	52,000	47.16	0.510	0.340	0.700
1998	23,101	16,548	39,647	32.76	22.19	54.95	5.2%	53,737	66.77	0.505	0.345	0.700
1999	18,524	12,820	28,344	38.16	28.87	65.66	39.6%	51,537	87.77	0.374	0.476	0.700
2000	8,771	7,314	16,085	41.66	29.54	71.53	66.8%	53,324	107.24	0.205	0.645	0.700
2001	5,095	4,377	8,472	43.85	31.14	74.99	80.8%	52,360	128.36	0.121	0.729	0.700
2002	3,258	2,882	6,141	45.04	32.19	77.23	87.8%	51,348	145.13	0.078	0.772	0.700
2003	2,380	2,148	4,528	45.81	32.97	78.88	91.3%	53,178	164.51	0.058	0.797	0.700
2004	1,814	1,181	2,998	46.37	33.40	79.98	93.2%	34,867	177.23	0.038	0.812	0.700
2005	890	458	1,348	46.90	33.57	80.47	95.5%	9,718	180.76	0.017	0.406	0.350
2006	428	200	627	47.05	33.64	80.70	98.1%	9,286	184.17	0.008	0.000	0.000
2007	200	98	298	47.13	33.68	80.81	98.7%	9,189	187.52	0.004	0.000	0.000
2008	68	18	114	47.18	33.69	80.85	97.6%	4,591	189.24	0.001	0.000	0.000

NOTES 1) SOLUTION GAS ASSUMED 450 SCF/STB (=80 VOL/VOL)
2) FUEL GAS ASSUMED 5 3 MMSCF/D (=0.15 MMm3/D)
3) INDICATIVE SALES GAS VOLUME OF 0 7 MMm3/D FOR 10 YEARS SHOWN

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Table 1

RAVVA FIELD, OIL/GAS/WATER PRODUCTION, WATER INJECTION FORECAST

40,000 BOPD PLATEAU, 100 MMBBL RESERVES

PERIOD	R10 BLOCK OIL PRODUCTION RATE (BOPD)	R17 BLOCK OIL PRODUCTION RATE (BOPD)	R10 & R17 BLOCKS OIL PRODUCTION RATE (BOPD)	R10 BLOCK CUMULATIVE OIL PRODUCTION (MMBBL)	R17 BLOCK CUMULATIVE OIL PRODUCTION (MMBBL)	R10 & R17 BLOCKS CUM OIL PRODUCTION (MMBBL)	PRODUCING WATER CUT (%)	WATER INJECTION RATE (BWPD)	CUMULATIVE WATER INJECTION (MMBBL)	ASSOCIATED GAS PRODUCTION RATE (MMm3/D)	FREE GAS PRODUCTION RATE (MMm3/D)	TOTAL GAS SALES RATE (MMm3/D)
EARLY YEARS BY QUARTER -												
1Q93	0	0	0	0.00	0.00	0.00	n.a.	0	0.00	0.000	0.000	0.000
2Q93	0	3,000	3,000	0.00	0.27	0.27	0.0%	0	0.00	0.038	0.000	0.000
3Q93	0	3,000	3,000	0.00	0.55	0.55	0.0%	0	0.00	0.038	0.000	0.000
4Q93	1,500	1,500	3,000	0.14	0.68	0.82	0.0%	0	0.00	0.038	0.000	0.000
1Q94	1,500	1,500	3,000	0.27	0.82	1.10	0.0%	0	0.00	0.038	0.000	0.000
2Q94	1,500	1,500	3,000	0.41	0.96	1.37	0.0%	0	0.00	0.038	0.000	0.000
3Q94	1,500	1,500	3,000	0.55	1.10	1.64	0.0%	0	0.00	0.038	0.000	0.000
4Q94	4,082	1,500	5,582	0.82	1.33	2.15	0.0%	0	0.00	0.071	0.000	0.000
1Q95	13,030	1,500	14,530	2.11	1.37	3.48	0.0%	0	0.00	0.185	0.000	0.000
2Q95	14,311	8,188	23,491	3.41	2.21	5.62	0.0%	20,000	1.83	0.299	0.000	0.000
3Q95	20,718	8,188	29,803	5.30	3.05	8.35	0.0%	38,000	5.29	0.381	0.469	0.700
4Q95	23,274	8,188	32,485	7.43	3.88	11.31	0.0%	43,078	9.22	0.414	0.436	0.700
FULL FORECAST BY YEAR -												
1993	375	1,875	2,250	0.14	0.68	0.82	0.0%	0	0.00	0.028	0.000	0.000
1994	2,141	1,500	3,641	0.82	1.33	2.15	0.0%	0	0.00	0.048	0.000	0.000
1995	17,634	7,265	25,099	7.43	3.66	11.31	0.0%	25,289	9.22	0.320	0.228	0.350
1996	23,127	16,873	40,000	15.87	10.04	25.91	0.0%	52,000	28.20	0.510	0.340	0.700
1997	23,127	16,873	40,000	24.31	16.20	40.51	0.0%	52,000	47.18	0.510	0.340	0.700
1998	23,127	16,873	40,000	32.75	22.36	55.11	0.0%	52,000	66.16	0.510	0.340	0.700
1999	23,375	16,337	39,813	41.34	28.29	69.57	6.6%	54,310	85.99	0.505	0.343	0.700
2000	16,608	12,448	29,057	47.35	32.83	80.16	34.5%	55,068	108.41	0.370	0.480	0.700
2001	10,304	6,068	16,382	51.11	35.78	86.89	60.6%	52,207	125.47	0.234	0.616	0.700
2002	8,551	5,243	13,784	53.50	37.70	91.18	73.2%	51,070	144.11	0.150	0.700	0.700
2003	4,443	3,703	8,146	55.13	38.05	94.17	82.6%	49,230	162.08	0.104	0.748	0.700
2004	3,163	2,751	5,914	56.21	40.05	96.33	87.3%	48,941	180.31	0.075	0.775	0.700
2005	2,484	2,171	4,655	57.16	40.84	98.02	88.8%	47,823	198.84	0.058	0.358	0.350
2006	1,585	1,533	3,178	57.76	41.40	99.17	88.8%	10,306	199.70	0.040	0.000	0.000
2007	1,287	847	2,244	58.27	41.71	99.86	73.2%	8,187	203.08	0.029	0.000	0.000
2008	847	478	1,325	58.56	41.89	100.47	65.0%	8,220	206.42	0.017	0.000	0.000
2009	478	283	762	58.76	41.99	100.75	91.4%	8,051	209.33	0.010	0.000	0.000

NOTES 1) SOLUTION GAS ASSUMED 450 SCF/STB (~80 VOL/VOL)
2) FUEL GAS ASSUMED 3.3 MMSCFD (~0.15 MMm3/D)
3) INDICATIVE SALES GAS VOLUME OF 0.7 MMm3/D FOR 10 YEARS SHOWN

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Table 2

RAVVA FIELD, OIL/GAS/WATER PRODUCTION, WATER INJECTION FORECAST

50,000 BOPD PLATEAU, 100 MMBBL RESERVES

PERIOD	R10 BLOCK OIL PRODUCTION RATE (BOPD)	R17 BLOCK OIL PRODUCTION RATE (BOPD)	R10 & R17 BLOCKS OIL PRODUCTION RATE (BOPD)	R10 BLOCK CUMULATIVE OIL PRODUCTION (MMBBL)	R17 BLOCK CUMULATIVE OIL PRODUCTION (MMBBL)	R10 & R17 BLOCKS CUM OIL PRODUCTION (MMBBL)	PRODUCING WATER CUT (%)	WATER INJECTION RATE (BWPD)	CUMULATIVE WATER INJECTION (MMBBL)	ASSOCIATED GAS PRODUCTION RATE (MMm3/D)	FREE GAS PRODUCTION RATE (MMm3/D)	TOTAL GAS SALES RATE (MMm3/D)
EARLY YEARS BY QUARTER -												
1Q93	0	0	0	0.00	0.00	0.00	n.a.	0	0.00	0.000	0.000	0.000
2Q93	0	3,000	3,000	0.00	0.27	0.27	0.0%	0	0.00	0.036	0.000	0.000
3Q93	0	3,000	3,000	0.00	0.55	0.55	0.0%	0	0.00	0.036	0.000	0.000
4Q93	1,500	1,500	3,000	0.14	0.68	0.82	0.0%	0	0.00	0.036	0.000	0.000
1Q94	1,500	1,500	3,000	0.27	0.82	1.10	0.0%	0	0.00	0.036	0.000	0.000
2Q94	1,500	1,500	3,000	0.41	0.96	1.37	0.0%	0	0.00	0.036	0.000	0.000
3Q94	1,500	1,500	3,000	0.55	1.10	1.64	0.0%	0	0.00	0.036	0.000	0.000
4Q94	5,260	1,500	6,760	1.03	1.23	2.26	0.0%	0	0.00	0.066	0.000	0.000
1Q95	18,420	1,500	19,920	2.71	1.37	4.08	0.0%	0	0.00	0.254	0.000	0.000
2Q95	20,300	12,780	33,080	4.56	2.53	7.10	0.0%	20,000	1.63	0.422	0.000	0.000
3Q95	28,700	12,780	42,480	7.27	3.70	10.97	0.0%	36,000	5.28	0.541	0.309	0.700
4Q95	33,460	12,780	46,240	10.32	4.87	15.18	0.0%	43,333	9.25	0.588	0.261	0.700
FULL FOREGAST BY YEAR -												
1993	375	1,875	2,250	0.14	0.68	0.82	0.0%	0	0.00	0.029	0.000	0.000
1994	2,440	1,500	3,940	1.03	1.23	2.26	0.0%	0	0.00	0.050	0.000	0.000
1995	25,470	9,860	35,430	10.32	4.87	15.18	0.0%	25,333	9.25	0.451	0.142	0.350
1996	30,000	20,000	50,000	21.37	12.17	33.44	0.0%	56,000	30.42	0.837	0.313	0.700
1997	27,543	19,520	47,063	31.33	18.28	50.82	0.4%	60,000	52.32	0.800	0.250	0.700
1998	16,817	15,899	34,316	36.12	25.02	83.14	24.8%	60,000	74.22	0.437	0.413	0.700
1999	14,021	11,050	25,071	43.24	29.08	72.30	43.1%	60,000	96.12	0.319	0.531	0.700
2000	10,214	8,456	18,670	48.87	32.14	78.11	57.9%	57,366	117.08	0.238	0.812	0.700
2001	7,810	6,543	14,353	49.62	34.53	84.35	67.8%	48,844	134.88	0.183	0.967	0.700
2002	8,075	5,151	11,227	52.04	36.41	88.45	75.1%	46,432	152.58	0.143	0.707	0.700
2003	4,835	4,026	8,863	53.80	37.86	91.66	80.8%	46,238	170.17	0.113	0.737	0.700
2004	3,638	3,341	7,266	55.24	39.10	94.34	84.4%	46,787	187.87	0.093	0.757	0.700
2005	3,178	2,666	5,844	56.40	40.08	96.47	88.2%	51,238	208.68	0.074	0.388	0.350
2006	2,504	1,976	4,480	57.31	40.80	98.11	90.9%	50,341	225.05	0.057	0.000	0.000
2007	1,688	1,445	3,333	58.00	41.32	99.33	93.2%	49,864	243.18	0.042	0.000	0.000
2008	637	888	1,725	58.31	41.65	99.96	94.8%	20,959	250.83	0.022	0.000	0.000

NOTES 1) SOLUTION GAS ASSUMED 450 SCF/STB (=80 VOL/VOL)
2) FUEL GAS ASSUMED 5.3 MMSCF/D (=0.15 MMm3/D)
3) INDICATIVE SALES GAS VOLUME OF 0.7 MMm3/D FOR 10 YEARS SHOWN

EB C:\OPW\RAVVA\T850_100.WK1

Table 2

RAVVA FIELD DEVELOPMENT

PROJECT COSTS

	Estimated Cost	Import Duty	Total
1. DEVELOPMENT OF R-10 AND R-17 BLOCKS			
- Drilling	44.54	4.90	49.44
- Platforms	33.95	8.67	42.62
- SPM	9.24	2.26	11.50
- Tanker Loading Line	9.55	1.71	11.25
- Flowlines	15.45	2.16	17.61
- Barge Mob/Demob	3.52	-	3.52
- Onshore Process Facilities	4.50	1.15	5.65
- Onshore Storage	23.31	1.51	24.82
- Water Injection Facilities	3.85	1.16	5.01
- Gas Plant (associated gas)	7.00	1.79	8.79
- Onshore Gas Pipeline	1.65	0.25	1.90
- Shore Base	1.10	-	1.10
- Environmental Studies	1.10	-	1.10
- Project Management	5.50	-	5.50
- Insurance	2.16	-	2.16
Sub-total	*166.42*	*25.56*	*191.98*
2. APPRAISAL EXPLORATION PROGRAMME			
- 3D Seismic Reprocessing	0.30	-	0.30
- Appraisal Drilling	19.01	2.09	21.10
Sub-total	*19.31*	*2.09*	*21.40*
3. GAS PROJECT (Non-Associated Gas)			
- Gas Plant	1.88	0.49	2.37
- Monopod Tower	2.20	0.35	2.55
- Gas Production Wells	4.00	0.44	4.44
- Offshore gas pipeline	6.49	1.04	7.53
Sub-total	*14.57*	*2.32*	*16.89*
4. GAS LIFT			
- Gas Compressor	3.31	0.99	4.30
- 4 inch Gas Lift Line	4.38	0.43	4.81
Sub-total	*7.69*	*1.42*	*9.11*
5. ABANDONMENT.	*18.00*	*0.00*	*18.00*
TOTAL PROJECT COST	*225.99*	*31.39*	*257.38*

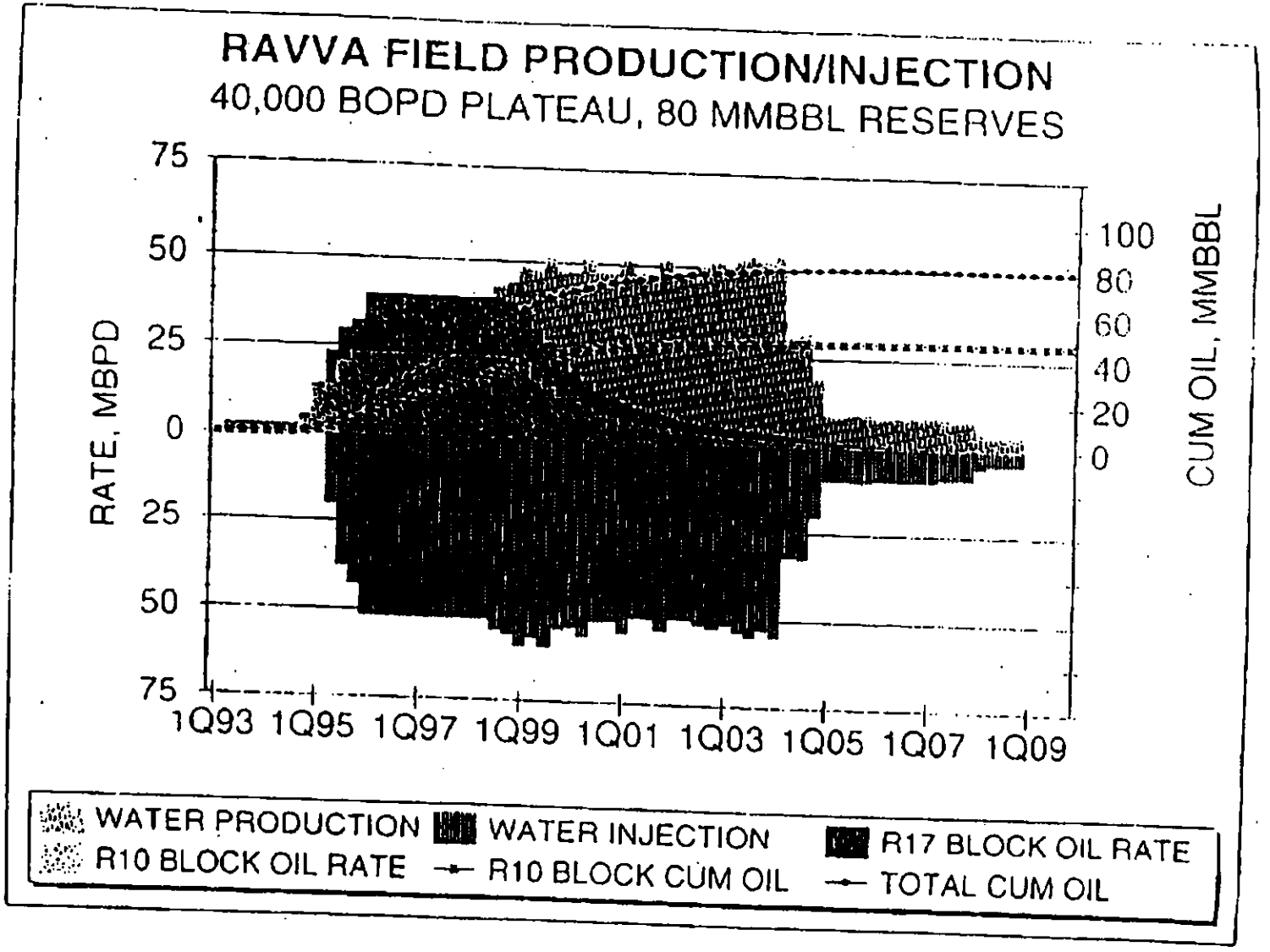
RAVVA FIELD DEVELOPMENT

DEVELOPMENT OPTION COST COMPARISON

(Excluding well costs and import duty)

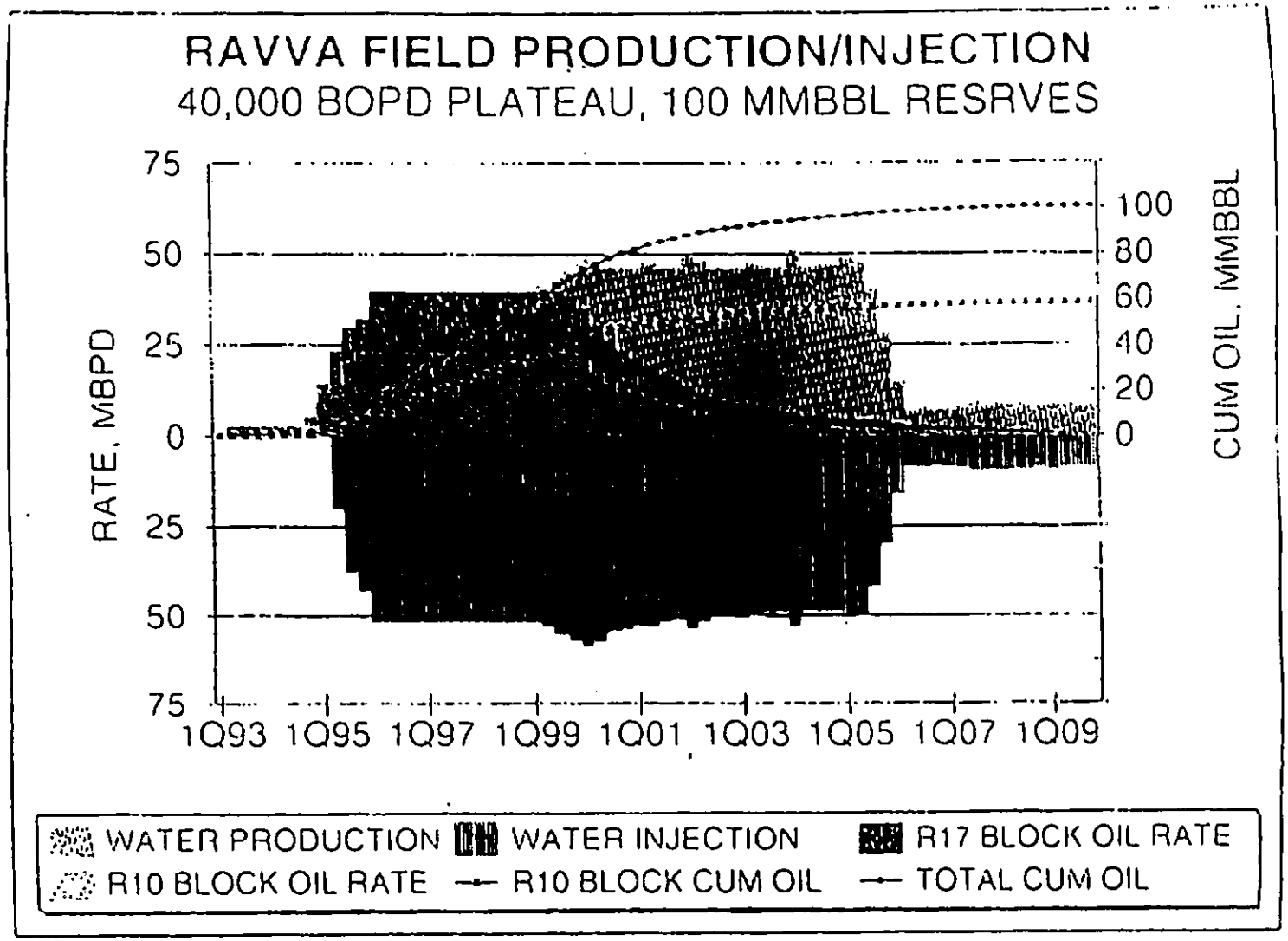
Option	Wellhead Towers	Production Processing Platform	Pipelines	Onshore Storage	Onshore Processing	Offshore Storage	FPSO Including mooring	Tanker Loading Facilities	Insurance	Total	Annual [illegible]
1	33.95	-	[illegible]	[illegible]	[illegible]		-	18.79	2.32	118.49	12.00
2	33.95	-					-	15.16	2.38	121.60	14.00
3	25.34	100.00					-	18.79	3.57	182.31	20.00
4	25.34	100.00	10.32			30.00		8.40	3.48	177.54	22.00
5	33.95	-	13.24				100.00		2.94	150.13	20.00
6	30.60	56.50	10.32			30.00		8.40	2.72	138.54	22.00

FIGURES



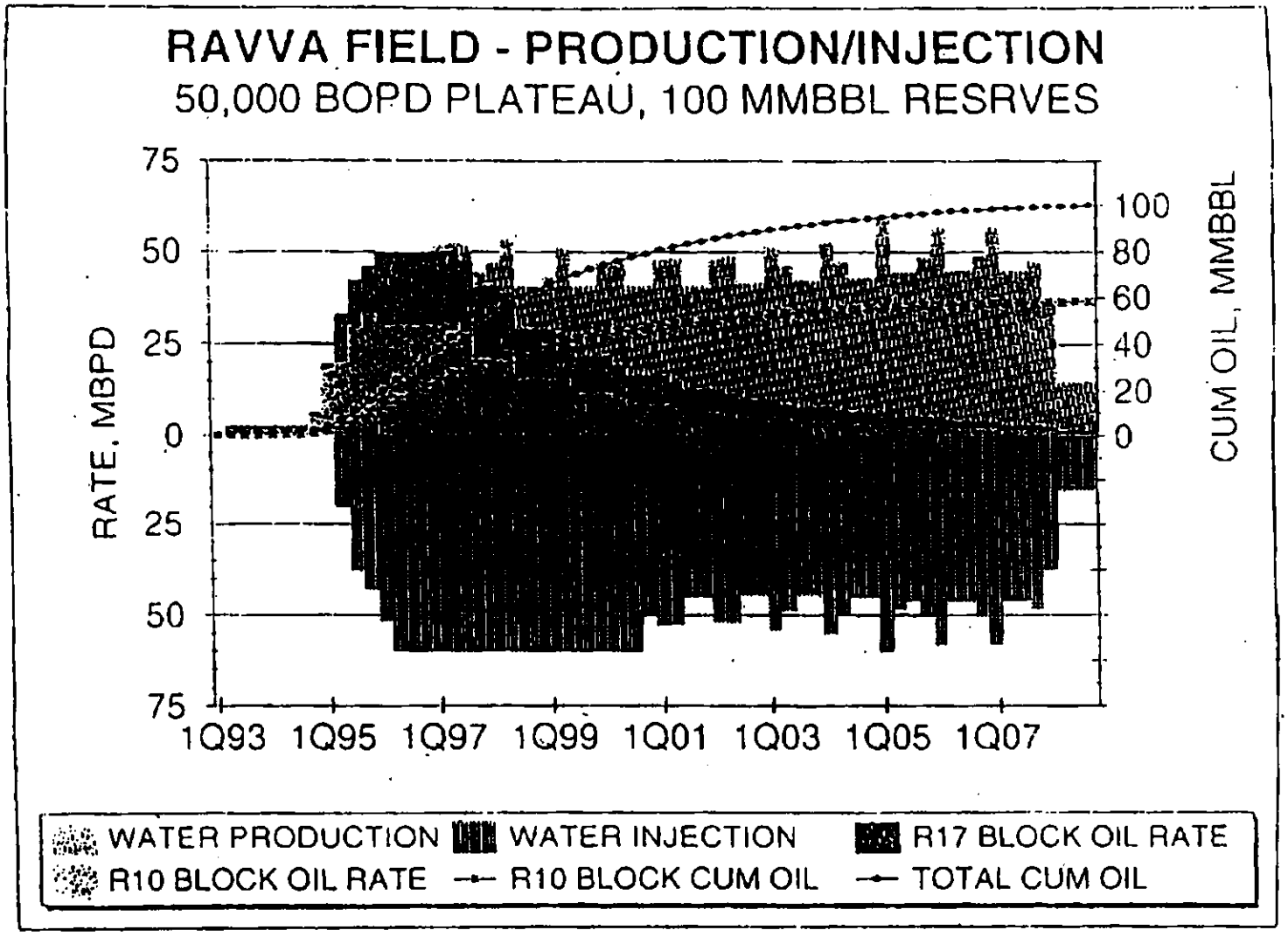
Command Petroleum, August [illegible]

FIGURE



Command Petroleum, August 1993

FIGURE 2



Command Petroleum, August 1993

FIGURE 3

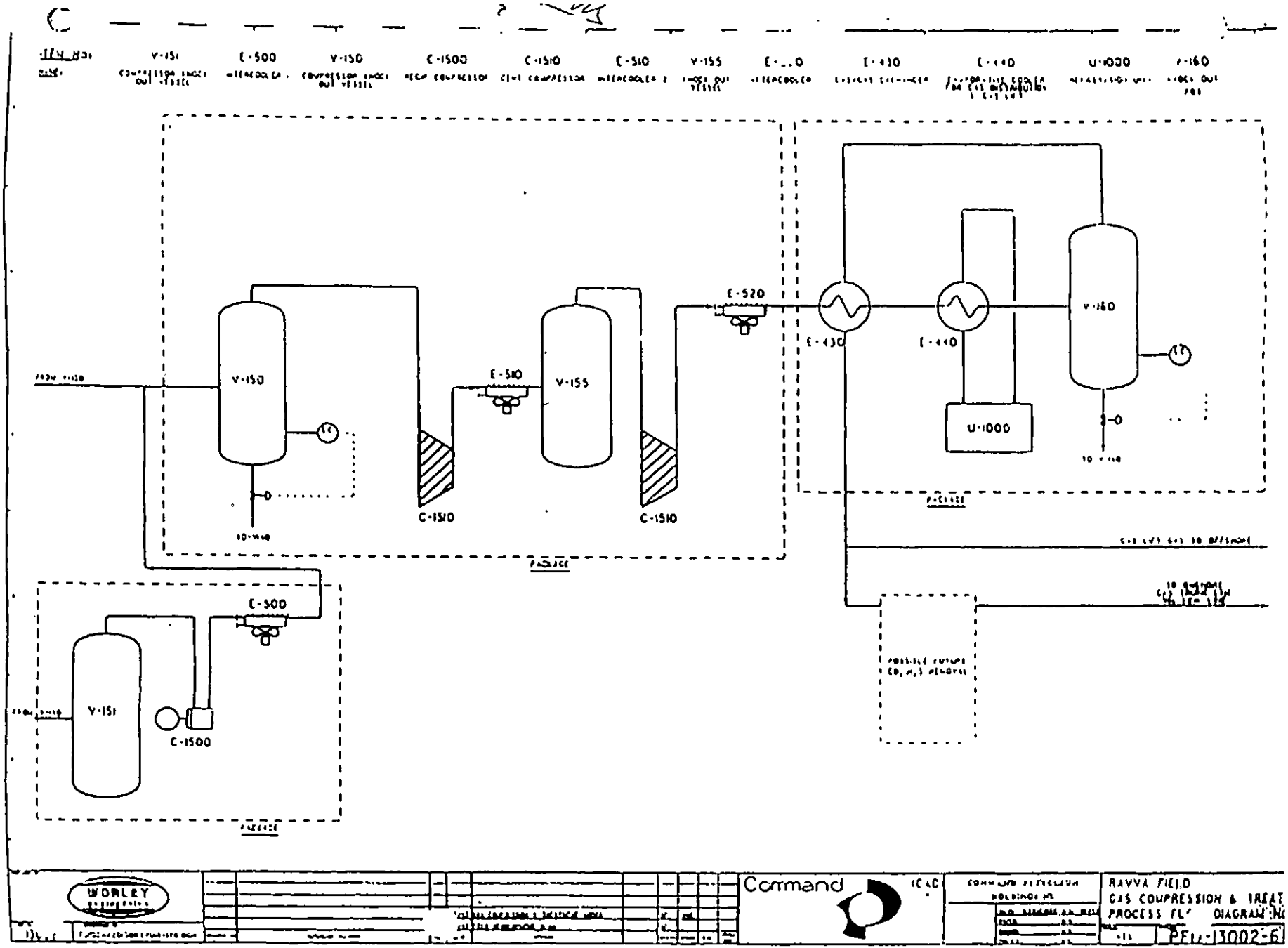

V-150
V-155
V-160
V-151
E-500
E-510
E-520
E-430
E-440
C-1500
C-1510
C-1510
U-1000
WORLEY
Command
RAVVA FIELD
GAS COMPRESSION & TREAT
PROCESS FL DIAGRAM
PFD-13002-6

FIGURE 4

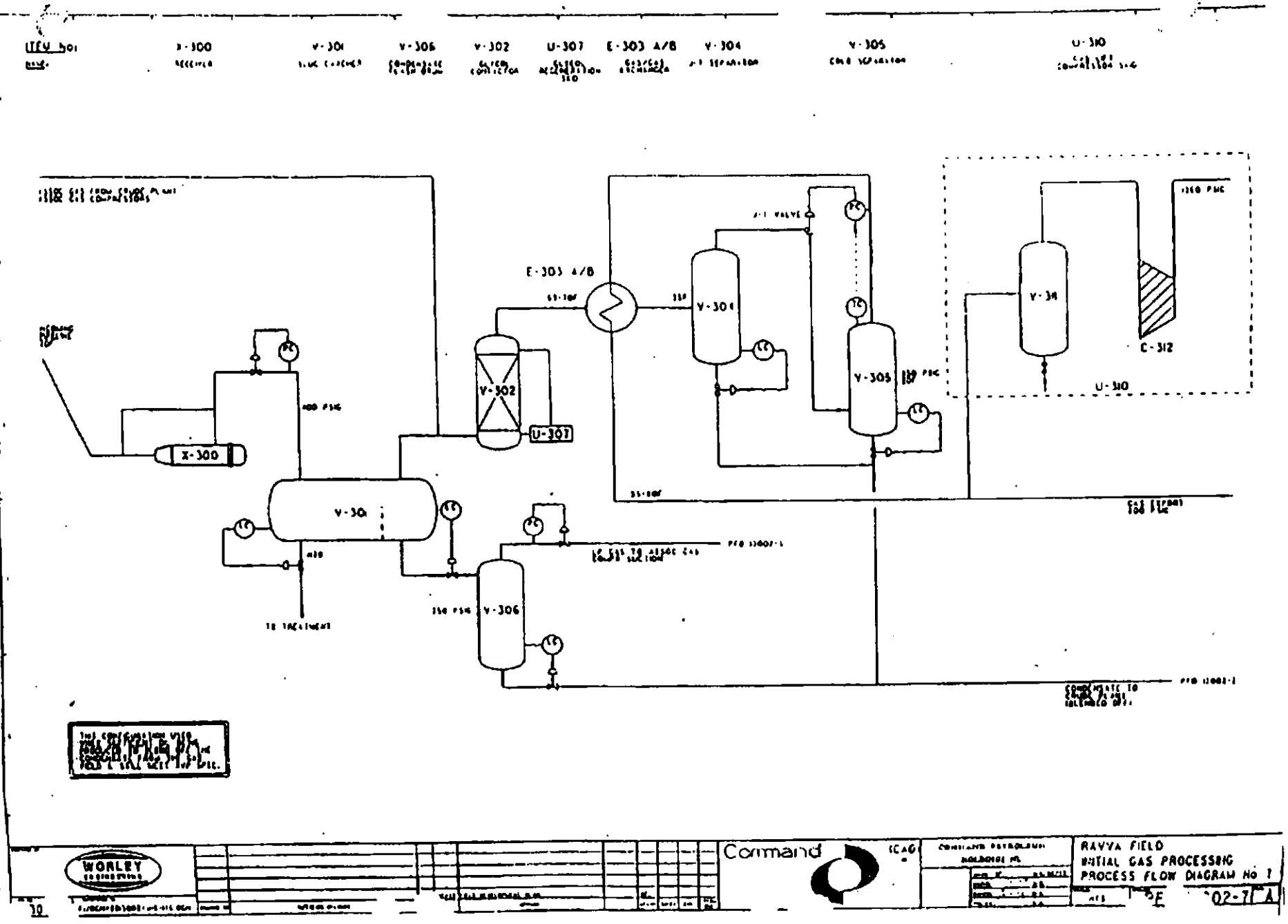

V-300
V-301
V-306
V-302
U-307
E-303 A/B
V-304
V-305
U-310
E-303 A/B
V-304
V-305
V-302
U-307
X-300
V-301
V-306
C-312
U-310
WORLEY
Command
RAVVA FIELD
INITIAL GAS PROCESSING
PROCESS FLOW DIAGRAM NO 1
02-7
A

FIGURE 5

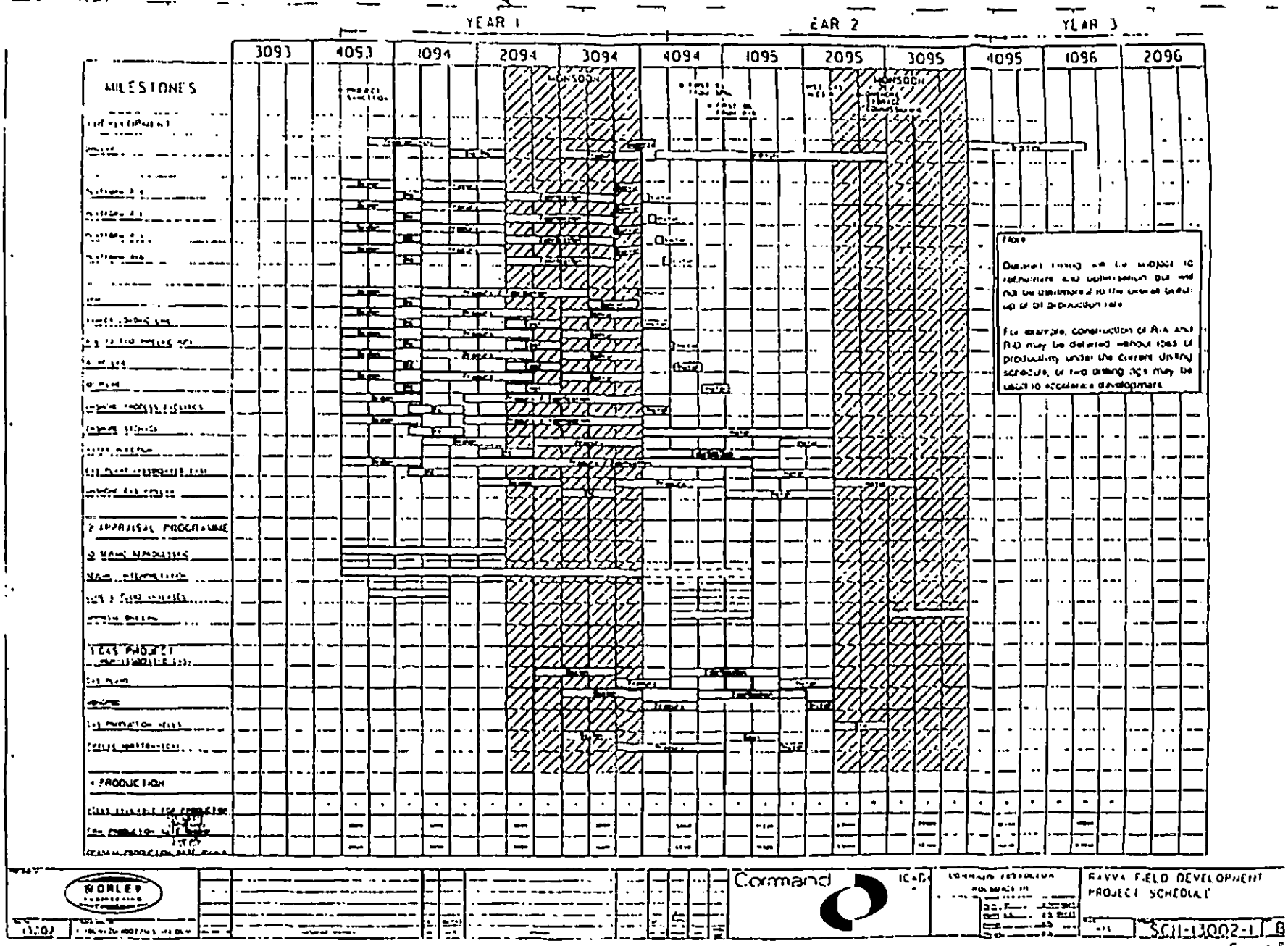

YEAR 1
YEAR 2
YEAR 3
3093
4093
1094
2094
3094
4094
1095
2095
3095
4095
1096
2096
MILESTONES
APPRAISAL PROGRAMME
TEAS PROJECT
PRODUCTION
Note
For example, construction of R/A and R/D may be delayed without loss of productivity under the current drilling schedule, or two drilling rigs may be used to accelerate development.
WORLEY
Command
RAVVA FIELD DEVELOPMENT
PROJECT SCHEDULE
SCH-1302-1
B

Figure 6

Command Petroleum Holdings N.L.

A.N.C. 001 695 398



Addendum 2 to

PROPOSED DEVELOPMENT PLAN

for the

RAVVA FIELD

by

COMMAND PETROLEUM HOLDINGS N.L.

for and on behalf of the

VIDEOCON-COMMAND JOINT VENTURE

Report No: 1993/040

October 1993

SUMMARY

This Addendum 2 to the Proposed Development Plan for the Ravva Field should be read in conjunction with both the full version of that Plan, which was submitted to the Government of India on 16 July 1993 and discussed in detail with Government representatives on 26-27 July 1993 in New Delhi, and Addendum 1 to that Plan, which was submitted in August 1993.

Addendum 2 is a copy of letter submitted to the Excom Group of ONGC in response to questions on the original bid and Development Plan.

The contents of the letter can be summarised as:

- **Financial Details**
  The members of the Videocon-Command-Marubeni Joint Venture are all well placed to fund their respective shares of the Ravva Field development costs.

- **Plateau Production Rate**
  The Joint Venture agrees to produce Ravva at a plateau rate of 35,000 BOPD. Command, as Operator of the Joint Venture, would not in any case produce the field at a rate in excess of that dictated by good reservoir management practices. We expect that the lower production rate will lengthen plateau duration and may delay the onset of water production, but we do not believe that capital costs will be affected or that ultimate recovery will necessarily be improved.

- **Exploration/Appraisal Programme**
  The Joint Venture will commit to nine firm exploration and appraisal wells outside the known R10 and R17 Blocks during Years 2 and 3 of the licence. A further three wells in that period will be contingent upon results of the firm wells.

- **Gas Development**
  The Joint Venture will pursue appraisal and development of non-associated gas reserves in the licence area, initially in the area of wells Ravva-1, -7 and -9.

- **Capital Expenditure Recovery Limit**
  The Joint Venture confirms its belief in its capital cost estimates by accepting that capital expenditures over and above 105% of the capital cost estimates will not be recoverable from cost oil.

Command Petroleum Holdings NL

A.C.N. 001 695 398

Sydney & Registered Office: Level 1 191 New South Head Road
Edgecliff NSW 2027 Australia
Phone 02 362 4233 Facsimile 02 362 4248 Int Tel 61 2 362 4233

26 October 1993

Mr R N Desai
General Manager (Geology)
Oil & Natural Gas Commission (Excom Group)
7th Floor, Bank of Baroda Building
16, Parliament Street
NEW DELHI 110 001
I N D I A

Dear Mr Desai,

RAVVA FIELD DEVELOPMENT APPLICATION

Further to your letter of 19 October addressed to Mr R N. Dhoot of Videocon International Limited (Videocon), Command Petroleum Holdings NL (Command) is pleased to take this opportunity to respond to your queries in a manner which we trust you will find satisfactory.

As you are aware, since the initial Application was lodged, Videocon and Command have been joined in the Application by Marubeni Corporation (Marubeni) to form the Videocon Command Marubeni Joint Venture (the Joint Venture). In July 1993 the Joint Venture submitted a report "Proposed Development Plan for the Ravva Field" and in August issued an Addendum to that report these reports are jointly referred to as the Development Plan and form the basis for our responses to your questions

1. FINANCIAL DETAILS

As stated in previous correspondence and discussions, if the Joint Venture's Application to develop the Ravva Field is successful the Joint Venture will be required to fund its share of a total US$236 million estimated project capital cost. This total cost includes development of the R10 and R17 Block oil and associated gas, the development of a non-associated gas pool and field abandonment costs, as detailed in the Development Plan and is inclusive of estimated Import Duty Further costs will be incurred by way of Signature and Production Bonuses operating expenses and appraisal and exploration activities Some of the costs will be funded from production revenue and the Joint Venture is well placed to fund the balance of the cost of the project

In the Development Plan, the Joint Venture indicated that in Years 1 and 2 it would commit to spend in the order of US$21.4 million (including Import Duty) outside the R10 and R17 Blocks, mainly on Year 2 drilling activity. Additional drilling was also anticipated in Year 3

Command is pleased to provide herewith further details of the Joint Venture's proposed appraisal and exploration programme in the form of Attachments 5 to 9 These attachments confirm a programme of six firm wells in Year 2 and three firm and three contingent wells in Year 3. The total cost of this programme is estimated to be US$42.9 million.

With regard to the foregoing comments and the associated attachments, it is important to note that

- No allowance has yet been made for the fact that licence award will, in all probability, be later than anticipated in the Development Plan.
- The programmes will necessarily retain flexibility so that their future direction may be modified to take into account the results of the drilling.

(b) Non-Associated Gas Development

The Joint Venture will pursue appraisal and development of non-associated gas reserves in the licence area, initially in the area of the R1,7,9 wells Following two early appraisal wells, two development wells are planned, giving a total of four producers. The Joint Venture believes that to meet contractual gas delivery requirements four producers will be necessary A pipeline to shore will be built and gas processing facilities will be installed sufficient to process 0 7 MMm3/D gas for sale

This non-associated gas development is as detailed in the Development Plan Anticipated cost is US$16.9 million, which will be spent mainly in Year 2.

4. LIMIT OF CAPITAL EXPENDITURE RECOVERY

Although your letter did not seek our response on this matter, Command would like to take this opportunity to comment.

The Joint Venture accepts that capital costs in excess of 5% above the budgeted capital costs of $218.0 million for carrying out the development (as detailed in the Development Plan and Attachment 10 to this letter) will not be recoverable from cost oil. Abandonment costs are excluded from this figure. Customs Duty is included

The quoted cost covers development of the oil and associated gas reserves in the R10 and R17 Blocks and the development of the non-associated gas reserves in the R1,7,9 area as presented in the Development Plan. It does not include the development of reserves in the upper "1600m" sand discovered by Ravva-34 or the development of possible reserves in the fault block east of Ravva-17 The development does include specified facilities through to point-of-sale of oil within the onshore terminal or at the offshore loading buoy and of gas at the plant outlet.

Videocon and Marubeni have both provided independent responses to your enquiry as to how they intend to fund their share of the Ravva Field Development. Videocon's response is contained in the covering note which accompanies this letter, while Marubeni's response has already been sent to you under separate cover, dated 21 October 1993

As far as Command is concerned, the company has a number of options available to fund its project cost obligations At this point in time, Command is yet to choose its preferred alternative but it is likely to be one, or a combination of the following :

- Balance Sheet
  With approximately US$26 million[1] in cash, absolutely no debt and a gross annual sales revenue of approximately US$18 million, Command's financial position is strong. This position will strengthen further when the company's November 1994 35 cent options fall due, injecting a further US$12 million cash into the company. Command could, therefore, utilise the strength of its balance sheet to fund a significant part of its share of the project

- Recourse to Corporate Parent
  As you know, Command is the international exploration and production arm of the US$1 billion-plus Snyder Oil Corporation (SOCO) which, earlier this year, raised US$105 million through a capital issue which was over subscribed ten times SOCO is also largely debt free and its balance sheet is very strong The company recently increased its undrawn bank credit facility from US$150 million to US$300 million in order to be well placed to fund new oil and gas projects. Thus, Command could draw upon the financial strength of its corporate parent with regard to financing part, or all, of its share of the project

- Third Party Project Finance
  Command has made enquiries with a select number of large international banks with regard to funding part of the cost of the Ravva Field Development via a limited recourse project loan. Although discussions are still at an early stage, Command has received a number of firm expressions of interest as evidenced by Attachment 1, which is a letter from ABN-AMRO, the fourteenth largest bank in the world. ABN-AMRO holds joint business interests with Command in The Netherlands.

- Capital Raising
  Command could issue new capital in one of two ways through an instant private placement of up to 10% of its stock to any one of a number of large institutions which are currently seeking to acquire more equity in the company, or through a fully underwritten Rights Issue Depending upon the option chosen and pricing details, such an issue could raise 100% of the funds required

- Marubeni Finance Facility
  As Marubeni states in its letter of 21 October, it could provide funding support to other Joint Venture parties As you know, there is no doubt as to Marubeni's financial strength and its ability to arrange the necessary finance

[1] US$ conversion at A$1 = US$0.65.

Therefore, you may be assured that if the Videocon-Command-Marubeni Joint Venture's Application is successful, all of the joint venturers will be well placed to fund their share of the Ravva Field Development cost.

2. IMPLICATION OF A REDUCTION OF THE 40,000 BOPD PLATEAU PRODUCTION RATE

Command has previously expressed its firm view that development drilling of the Ravva Field will confirm its ability to produce at a plateau rate of 40,000 BOPD via the planned wells and facilities. It has also always been emphasised that we would never produce the field in a manner which might have any detrimental effect on the reservoir, the wells or any of the surface equipment.

The Joint Venture recognises that some concerns could exist within ONGC that it might be impossible or unwise to produce at this rate. If this is the case and if, after the results of the the programme of development drilling, completion and testing are available, ONGC's still has valid concerns, the Joint Venture assures the Government of India that it will agree to produce the field at a plateau rate as low as 35,000 BOPD. We would expect any rate restriction to be reviewed at regular intervals with due regard to field performance

A plateau rate of 35,000 BOPD would be comfortably achievable under the Development Plan. The Joint Venture's oil production and water injection programme is planned to maintain reservoir pressure and provide efficient sweep and we believe the 35,000 BOPD plateau rate could be maintained for more than 4 years and produce almost two-thirds of the estimated recoverable reserves of 100 MMBO. Attachment 2 compares the production forecasts for the 35,000 and 40,000 BOPD plateau rate cases. Attachments 3 and 4 show, for a 35,000 BOPD plateau rate, the forecast of field oil and water production rates and the water injection necessary to maintain reservoir pressure

As you know, the Joint Venture's Development Plan involves drilling 19 new wells, 11 of which may be dual completions. When the four existing producing wells are taken into account, 20 production completions and 14 injection completions are anticipated. If more wells are necessary to achieve the plateau rate of 35,000 BOPD (which is actually less than 2,000 BOPD per completion) the Joint Venture will have the capacity to drill more wells from the platforms or, at very low cost, to install further platforms from which additional wells may be drilled.

There are both technical and commercial implications to producing the R10 and R17 Blocks at a plateau rate of 35,000 BOPD instead of 40,000 BOPD

- Production Plateau Prolonged by 9 months (20%)
  Attachment 2 compares the estimated production profiles for plateau production rates of 35,000 and 40,000 BOPD. As would be expected, a longer plateau life is forecast for the lower production rate.

- Possible Delay to Onset of Water Production
  A lower plateau rate may delay the onset of water production at crestal wells, as gravity fluid segregation will be slightly more efficient. Oil recovery at breakthrough is not expected to be significantly different

- Ultimate Recovery Unaffected
  A lower well plateau rate is not expected to increase ultimate recovery from the R10 and R17 Blocks.

- Importance of Non-Associated Gas to Gas Sales
  A non-associated gas development is planned to complement the production of gas associated with the R10 and R17 Block oil. With the lower oil rate the contribution to sales from associated gas would be correspondingly smaller. Thus, the significance of early appraisal and development of non-associated gas, in terms of both reserves and deliverability, assumes a greater importance. This is reflected in Command's appraisal and development drilling programme detailed elsewhere in this letter.

- Participants' Project Economics Downgraded
  The lower plateau oil rate would have an adverse impact on the project economics. Participants' capital exposure would increase, the project payback period would be longer and the Rate of Return to all participants would be lower. Despite this economic downgrading of the project, the Videocon-Command-Marubeni Joint Venture hereby assures the Government of India that it would still enthusiastically pursue the work programme described in the Development Plan as well as the associated aggressive appraisal and exploration programme.

- Capital Expenditure Unaffected
  Even if, for whatever reason, the plateau rate for the R10 and R17 Block development was restricted to 35,000 BOPD, Command would still intend to carry out the development activities as detailed in the Development Plan, including the installation of onshore storage of 500,000 barrels and an onshore oil processing capacity in excess of 50,000 BOPD. This would allow for the early development of satellite oil pools in a timely manner, since development would not have to wait until the end of the R10 and R17 Block plateau period.

3. WORK PROGRAMME AND INVESTMENT OUTSIDE THE R10 AND R17 BLOCKS

(a) Appraisal and Exploration Activities

As Command stated in the Development Plan, it is the Joint Venture's intention to aggressively explore and appraise other parts of the Ravva Licence Area beyond the R10 and R17 Blocks. The objective of the Joint Venture's exploration and appraisal efforts in these areas is to identify and develop additional oil and gas reserves as quickly as possible so as to optimise use of the proposed facilities and, in the case of gas, to develop appropriate gas markets. These activities would enhance the project economics, thereby also providing the Government with a greater income from the project.

Our evaluation of the potential of the Ravva Licence Area beyond the R10 and R17 Blocks - presented to you in various reports and discussions during the last several months - suggests that these additional reserves could be commercially quite significant, particularly since the threshold for development of isolated oil pools is expected to be as low as 2 MMBO recoverable oil.

ATTACHMENTS

1. ABN-AMRO Letter
2. Rate/Cumulative Comparison - 35,000 BOPD vs 40,000 BOPD
3. Ravva Oil - Water Production & Injection Forecast (Figure)
4. Ravva Oil - Water Production & Injection Forecast (Table)
5. Year 2 Drilling Schedule
6. Years 2 and 3 Drilling Schedule
7. Years 1 to 3 Appraisal and Exploration Drilling Programme/Locations
8. Schematic Ravva E Gas Development, R1, 7, 9 Blocks
9. Tabulation of Proposed Exploration and Appraisal Programme
10. Development Capital Costs

5. FINAL COMMENTS

The Videocon-Command-Marubeni Joint Venture trusts that the foregoing comments satisfactorily address your queries.

As you are aware, the Joint Venture very much wishes to be granted the opportunity to develop the Ravva Field, in conjunction with ONGC as a co-venturer, for the mutual benefit of all parties, particularly the Government and people of India.

Yours sincerely,
COMMAND PETROLEUM HOLDINGS NL
A C N 001 693 390

DR. JOHN DORAN
Managing Director

ABN·AMRO

STRICTLY PRIVATE & CONFIDENTIAL

Mr John P. Gracey
General Manager
Command Petroleum Holdings NL
191 New South Head Road, Level 1
Edgecliff NSW 2027

Department: Project Finance
Telephone: 223 3000
Fax: 223 4310
Reference: MSS/CW:jc
Date: 6 August 1993

Re: Joint Venture Development of the
Ravvi Oilfield
Bay of Bengal, India

Dear John,

In relation to the abovementioned development and your finance requirement proposed in support of this project, you have requested us to confirm our support for Command Petroleum Holdings NL's bid. ABN AMRO Australia Limited ("ABN AMRO") has examined information supplied by yourselves and, based on our preliminary review of this information, we believe that the general terms described appear to form a sound basis upon which your portion of the development may be financed

We note that a comprehensive solution to address the project's total cost may also be a basis for raising finance In addition there may be opportunities to optimise a financing plan based on local, offshore, export credit agency and other sources which may be applicable At this early stage, we have not investigated these alternatives or the financing requirements of the other sponsors but believe with further involvement such financial arrangements may show some merit

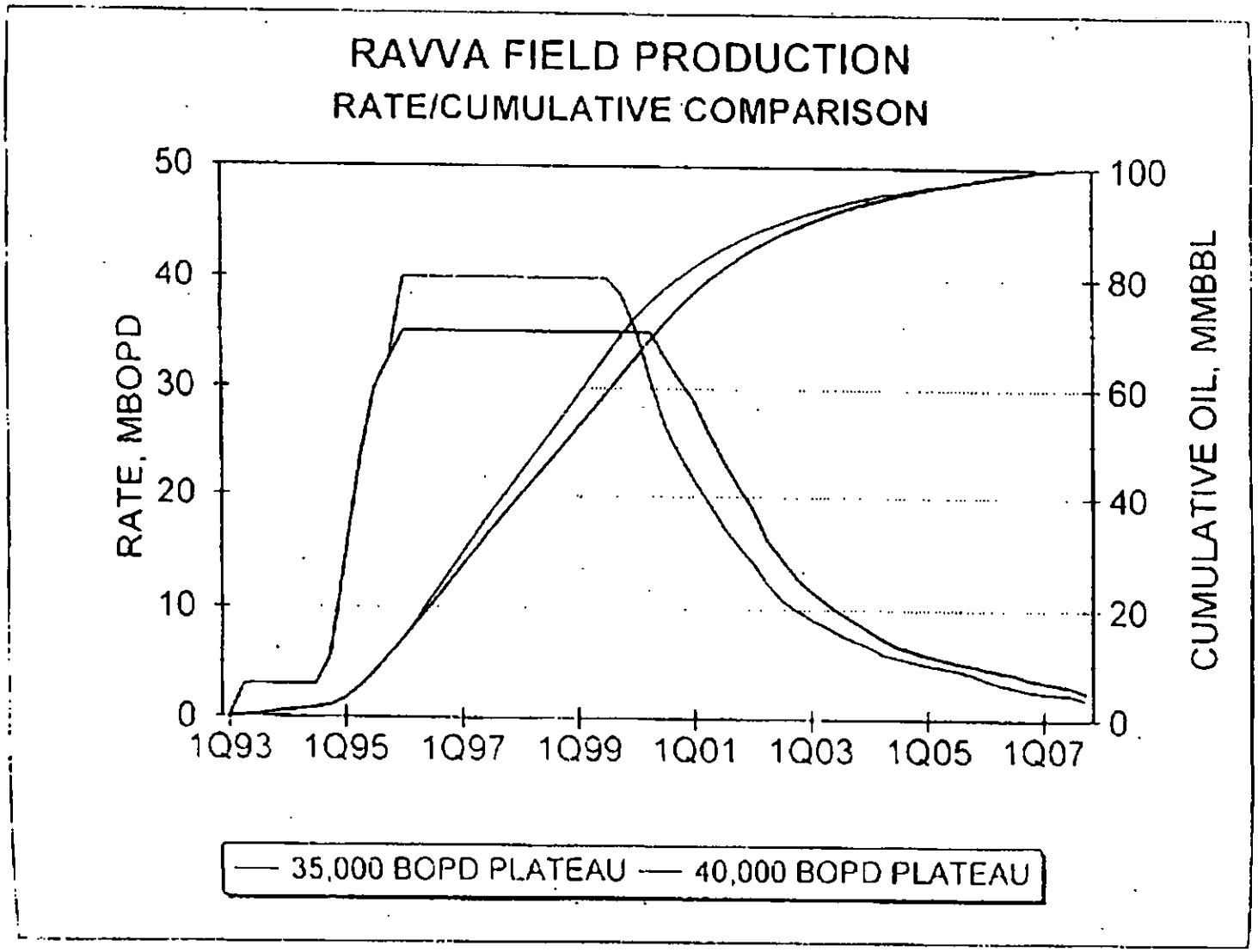
Attachment 1

ABN AMRO has demonstrated its commitment to project and oil and gas financing throughout the world. In 1992, the bank was the sixth largest project finance underwriter and remains one of the world's top energy banks

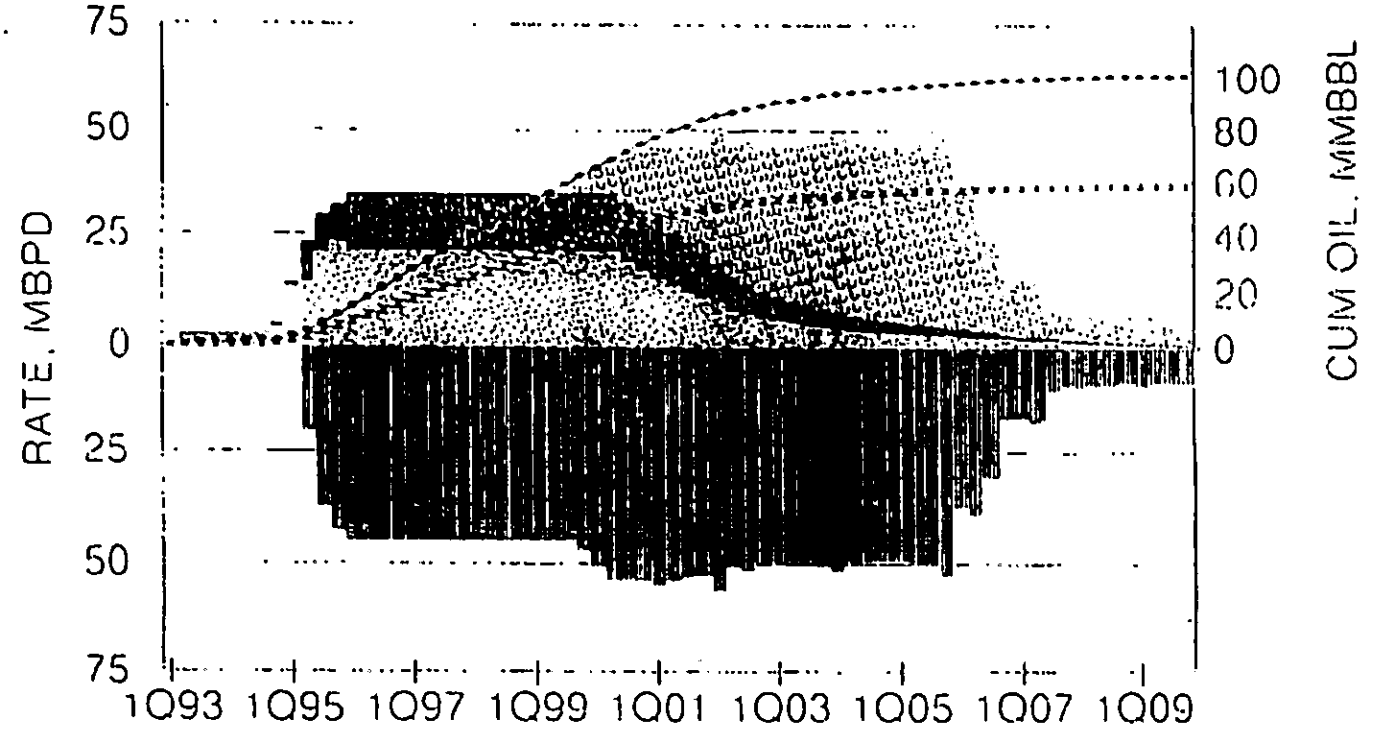
As you will appreciate, this letter is not a commitment to lend Any commitment by ABN AMRO to provide a financial undertaking is subject satisfactory assessment of the commercial features of the tender, customary due diligence, further evaluation of the project financials, an independent technical review of the project, no material adverse change to the project or its sponsors and negotiation of satisfactory documentation with major parties (inter alia ONGC, Command Petroleum, Videocon etc.) all on terms and conditions satisfactory to ABN AMRO.

This letter is exclusively in support of Command Petroleum's bid and should not be interpreted as being available in support of any other bid. We wish you every success in your negotiations and look forward to satisfactory resolution of all issues.

Yours faithfully,
ABN AMRO AUSTRALIA LIMITED


RAVVA FIELD PRODUCTION
RATE/CUMULATIVE COMPARISON
RATE, MBOPD
CUMULATIVE OIL, MMBBL
50
40
30
20
10
0
100
80
60
40
20
0
1Q93
1Q95
1Q97
1Q99
1Q01
1Q03
1Q05
1Q07
35,000 BOPD PLATEAU
40,000 BOPD PLATEAU

RAVVA FIELD PRODUCTION/INJECTION
35,000 BOPD PLATEAU, 100 MMBBL RESRVES



Attachment 3

COMMAND PETROLEUM HOLDINGS NL

RAVVA FIELD, OIL/GAS/WATER PRODUCTION, WATER INJECTION FORECAST

35,000 BOPD PLATEAU, 100 MMBBL RESERVES

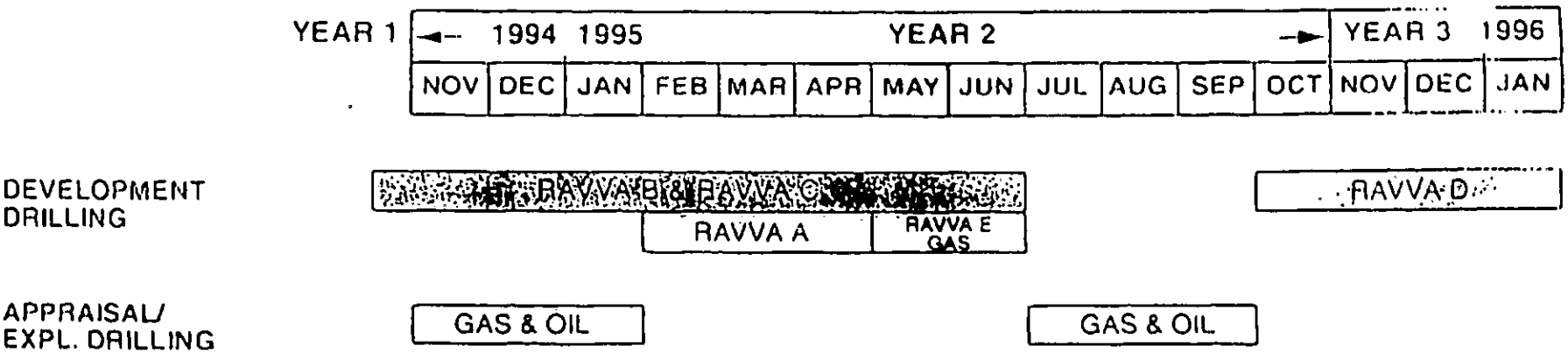
PERIOD	R10 BLOCK OIL PRODUCTION RATE (BOPD)	R17 BLOCK OIL PRODUCTION RATE (BOPD)	R10 & R17 BLOCKS OIL PRODUCTION RATE (BOPD)	R10 BLOCK CUMULATIVE OIL PRODUCTION (MMBBL)	R17 BLOCK CUMULATIVE OIL PRODUCTION (MMBBL)	R10 & R17 BLOCKS CUM OIL PRODUCTION (MMBBL)	PRODUCING WATER CUT (%)	WATER INJECTION RATE (BWPD)	CUMULATIVE WATER INJECTION (MMBBL)	ASSOCIATED GAS PRODUCTION RATE (MMm3/D)	FREE GAS PRODUCTION RATE (MMm3/D)	TOTAL GAS SALES RATE (MMm3/D)
EARLY YEARS BY QUARTER												
1Q93	0	0	0	0 00	0 00	0 00	n a	0	0 00	0 000	0 000	0.000
2Q93	0	3 000	3 000	0 00	0 27	0 27	0 0%	0	0 00	0 038	0 000	0.000
3Q93	0	3 000	3 000	0 00	0 55	0 55	0 0%	0	0 00	0 038	0 000	0 000
4Q93	1 500	1 500	3 000	0 14	0 68	0 82	0.0%	0	0 00	0 038	0.000	0.000
1Q94	1 500	1 500	3 000	0 27	0 82	1 10	0.0%	0	0.00	0 038	0 000	0.000
2Q94	1,500	1,500	3,000	0 41	0 96	1.37	0.0%	0	0 00	0 038	0 000	0.000
3Q94	1,500	1,500	3,000	0 55	1 10	1.64	0.0%	0	0 00	0 038	0.000	0.000
4Q94	4,062	1,500	5,562	0 92	1 23	2.15	0.0%	0	0.00	0 071	0 000	0.000
1Q95	13 030	1 500	14 530	2 11	1 37	3.48	0.0%	0	0 00	0 185	0 000	0.000
2Q95	14 311	9,186	23,497	3 41	2 21	5.62	0.0%	20,000	1 83	0 299	0.000	0 000
3Q95	20,718	9 186	29,903	5 30	3 05	8 35	0.0%	38,000	5.29	0 381	0 469	0 700
4Q95	23 279	9 186	32,465	7 43	3 88	11 31	0 0%	43,078	9 22	0 414	0 436	0 700
FULL FORECAST BY YEAR												
1993	375	1,875	2,250	0 14	0 68	0 82	0.0%	0	0 00	0 029	0 000	0 000
1994	2 141	1,500	3,641	0 92	1 23	2.15	0.0%	0	0.00	0 046	0 000	0.000
1995	17,834	7,265	25 099	7.43	3 88	11 31	0 0%	25,269	9 22	0 320	0 226	0.350
1996	21,000	14,000	35 000	15 09	8 99	24.09	0 0%	45,500	25 83	0 446	0 404	0 700
1997	21,000	14,000	35,000	22 76	14.10	36.86	0 0%	45,500	42 44	0 446	0 404	0 700
1998	21,000	14,000	35 000	30 42	19 21	49 64	0 0%	45,500	59 05	0 446	0 404	0 700
1999	21,000	14,000	35,000	38 09	24 32	62 41	1 1%	45,873	75 79	0 446	0 404	0.700
2000	19,401	14,000	33,401	45 17	29 43	74 60	22.8%	53,264	95 23	0 426	0 424	0.700
2001	12,838	11 934	24,812	49 88	33 79	83 67	46 5%	53 858	114 89	0 316	0.534	0 700
2002	7 939	7,821	15 561	52 77	36 57	89 35	67 5%	52,481	134.04	0 198	0.652	0.700
2003	5,310	4 988	10 298	54 71	38 39	93 10	78 1%	50 016	152 30	0 131	0 719	0.700
2004	3,606	3 511	7 116	56 03	39 67	95 70	85.2%	50,161	170 61	0 091	0 759	0 700
2005	2 774	2 666	5 440	57 04	40 65	97 69	88 9%	50 637	189 09	0 069	0 356	0 350
2006	2,004	2 010	4 015	57 77	41 38	99 15	90 8%	31,551	200 61	0 051	0 000	0.000
2007	1,397	1 038	2 436	58 28	41 76	100 04	81 2%	13,652	205 59	0 031	0 000	0.000
2008	847	478	1,325	58 59	41 93	100 53	85 0%	9 220	208.96	0 017	0 000	0 000
2009	478	283	762	58 77	42 04	100 80	91 4%	9 051	212 26	0 010	0 000	0.000

NOTES
1) SOLUTION GAS ASSUMED 450 SCF/STB (=80 VOL/VOL)
2) FUEL GAS ASSUMED 5 3 MMSCF/D (=0 15 MMm3/D)
3) INDICATIVE SALES GAS VOLUME OF 0 7 MMm3/D FOR 10 YEARS SHOWN
4) ASSUMED RAVVA TO PLATFORM TIE IN COMPLETED SEPTEMBER 1993

Attachment 4

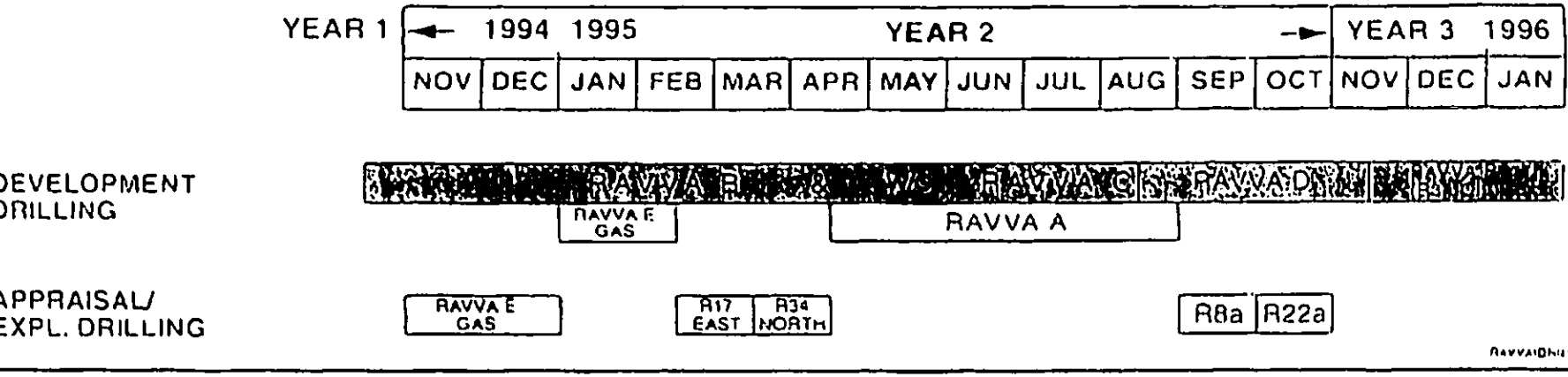
YEAR 2 DRILLING SCHEDULE

ORIGINAL*



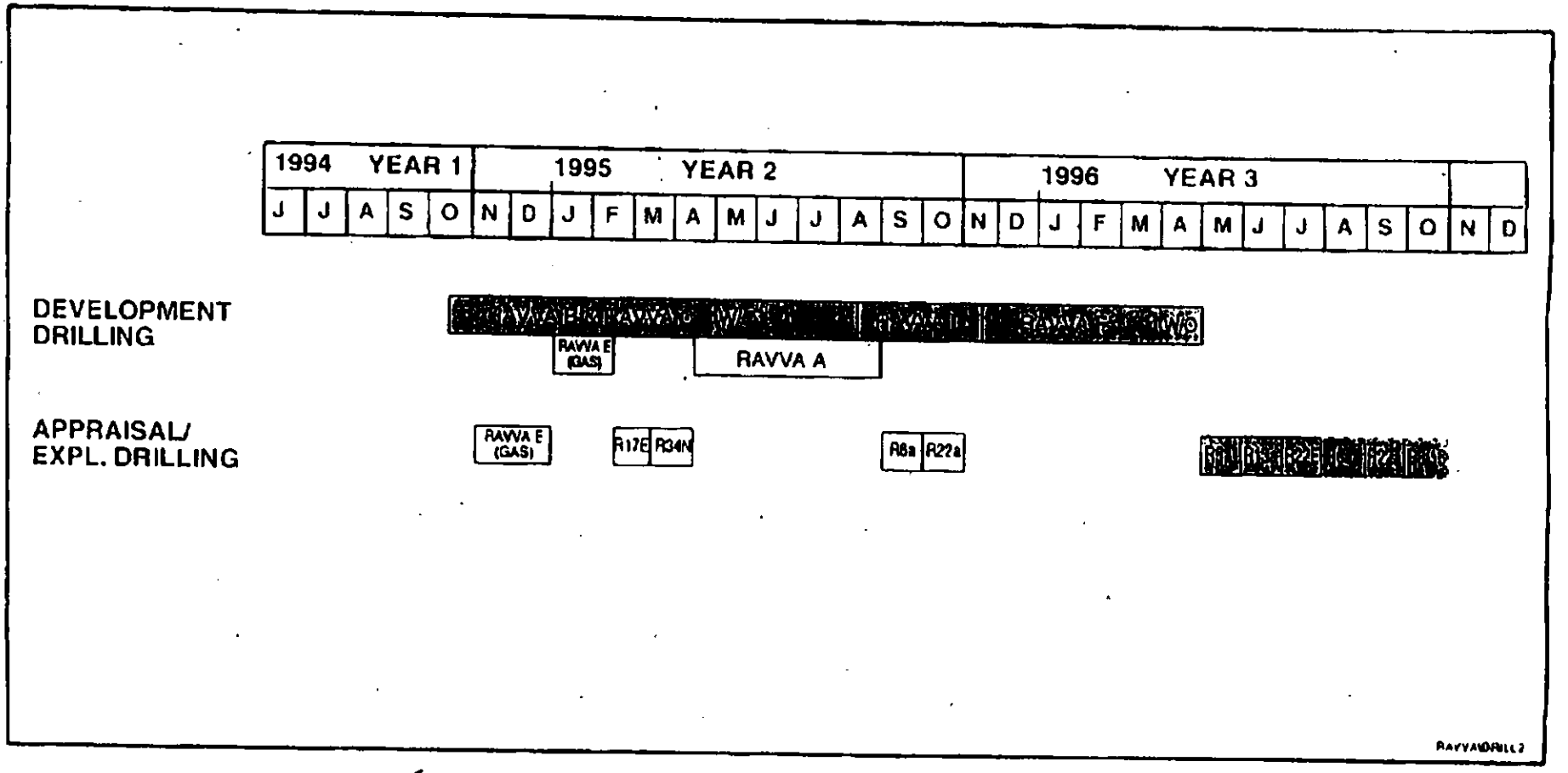
* Extracted from Figure 6, August Addendum to Ravva Development Plan

CURRENT PROPOSAL

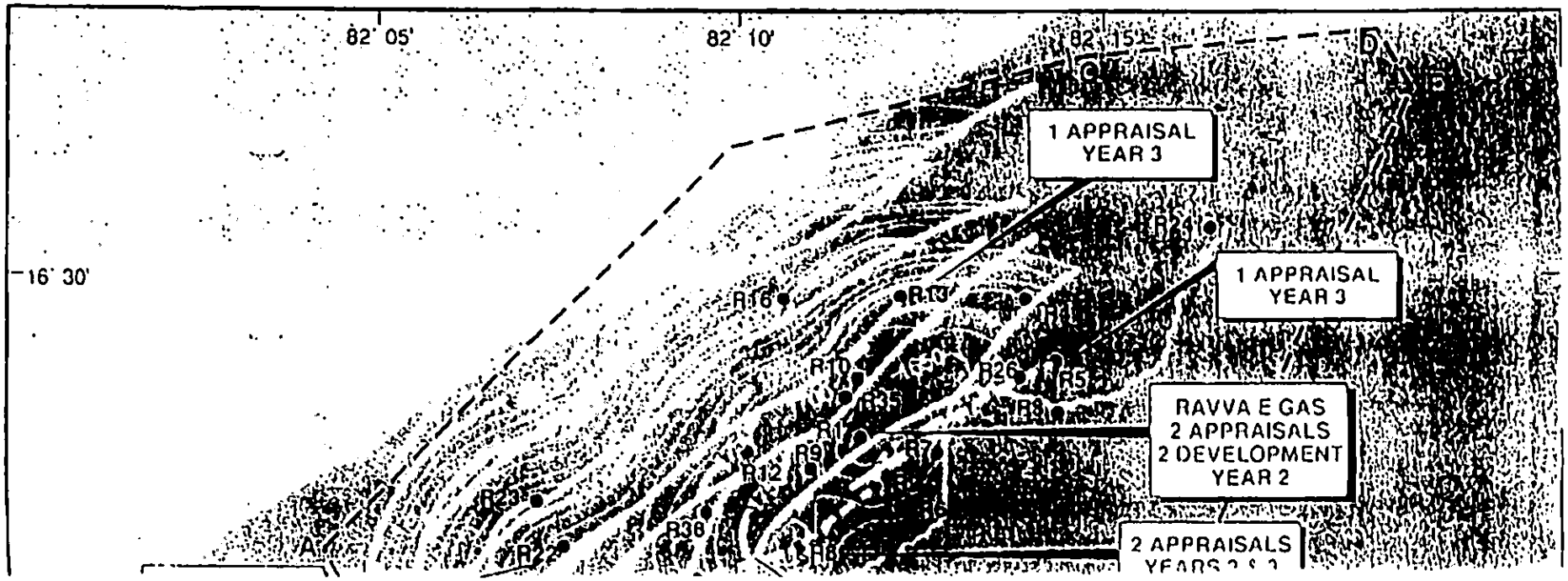


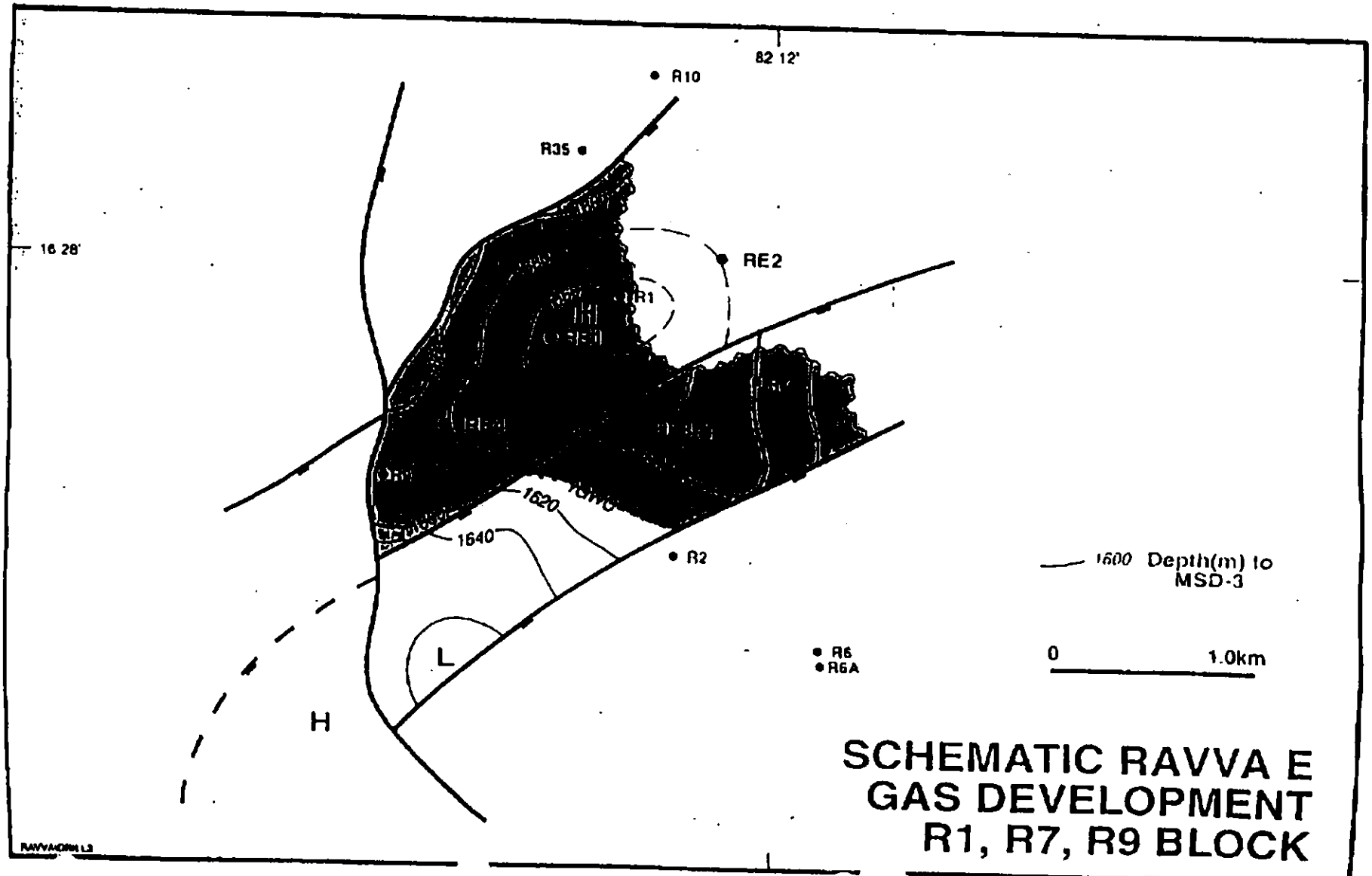
Attachment 5

YEARS 2 AND 3 DRILLING SCHEDULE



Attachment 6


82° 05'
82° 10'
82° 15'
16° 30'
1 APPRAISAL
YEAR 3
1 APPRAISAL
YEAR 3
RAVVA E GAS
2 APPRAISALS
2 DEVELOPMENT
YEAR 2
2 APPRAISALS
R16
R13
R10
R35
R1
R9
R12
R23
R36
R2
R24
B26
R5
R8
R7



Attachment A

ATTACHMENT 9

TABULATION OF PROPOSED EXPLORATION & APPRAISAL PROGRAMME

YEAR	WORK PROGRAMME	COST US$ million
1	Studies : Geological & Geophysical • Reprocess 800 kms 2D data (including 613 kms within the Licence) • Reprocess 4,400 kms 3D data • Development geophysics, including · amplitude and phase displays · seismic inversion · seismic modelling · AVO analyses • Core and fluid analyses to calibrate log analyses	21.4
2	Studies : Geological & Geophysical - Ongoing Firm Drilling Programme RE1 Appraisal of Ravva 1,7,9 gas pool, drilled through a template to be used in the Ravva E platform, see Attachment 8. RE2 Appraisal of northern part of the Ravva 1,7,9 structure. Deviated well drilled from template, see Attachment 8 R17E Exploration well in the fault block east of the Ravva 17 pool R34N Appraisal well north of R34 to define the extent and hydrocarbon content of the "1600m" sand which lies above the main reservoir unit in the R-17 Block. It was encountered for the first time in R34 R8a Appraisal of gas and oil intersected in R8 R22a Appraisal of gas intersected in R22.	
3	Geological & Geophysical Studies - Ongoing Firm Driling Programme R5a Appraisal of oil pool in R5. R13a Appraisal of several oil and gas pools intersected in R13 R22E Exploration well south-east of R22, targetting sandstones truncated beneath a major unconformity	11.0
	Contingent Drilling Programme R8a Appraisal of R8 oil and gas R22a Appraisal of R22 gas R8/15 Exploration well, targetting a sub-unconformity structural stratigraphic play between R8 and R15	10.5
	TOTAL	42.9

Refer also Attachments 5 to 8

ATTACHMENT 10

RAVVA FIELD DEVELOPMENT CAPITAL COSTS

ITEM	COST US$ million
Development of R10 and R17 Blocks Oil and Associated Gas Reserves Drill and Complete 19 Wells SPM and Tanker Loading Line Four Platforms Production/Injection Pipelines to/from Shore Infield Flowlines Onshore Oil Process Facilities Onshore Oil Storage Gas Treatment and Compression Water Injection Gas Lift Pipeline and Compression Project Management, etc.	201.1
Development of R1,7,9 Non-Associated Gas Reserves Drill and Complete 2 Wells One Monopod Tower Production Pipeline to Shore Onshore Gas Treatment Plant	16.9
TOTAL	218.0

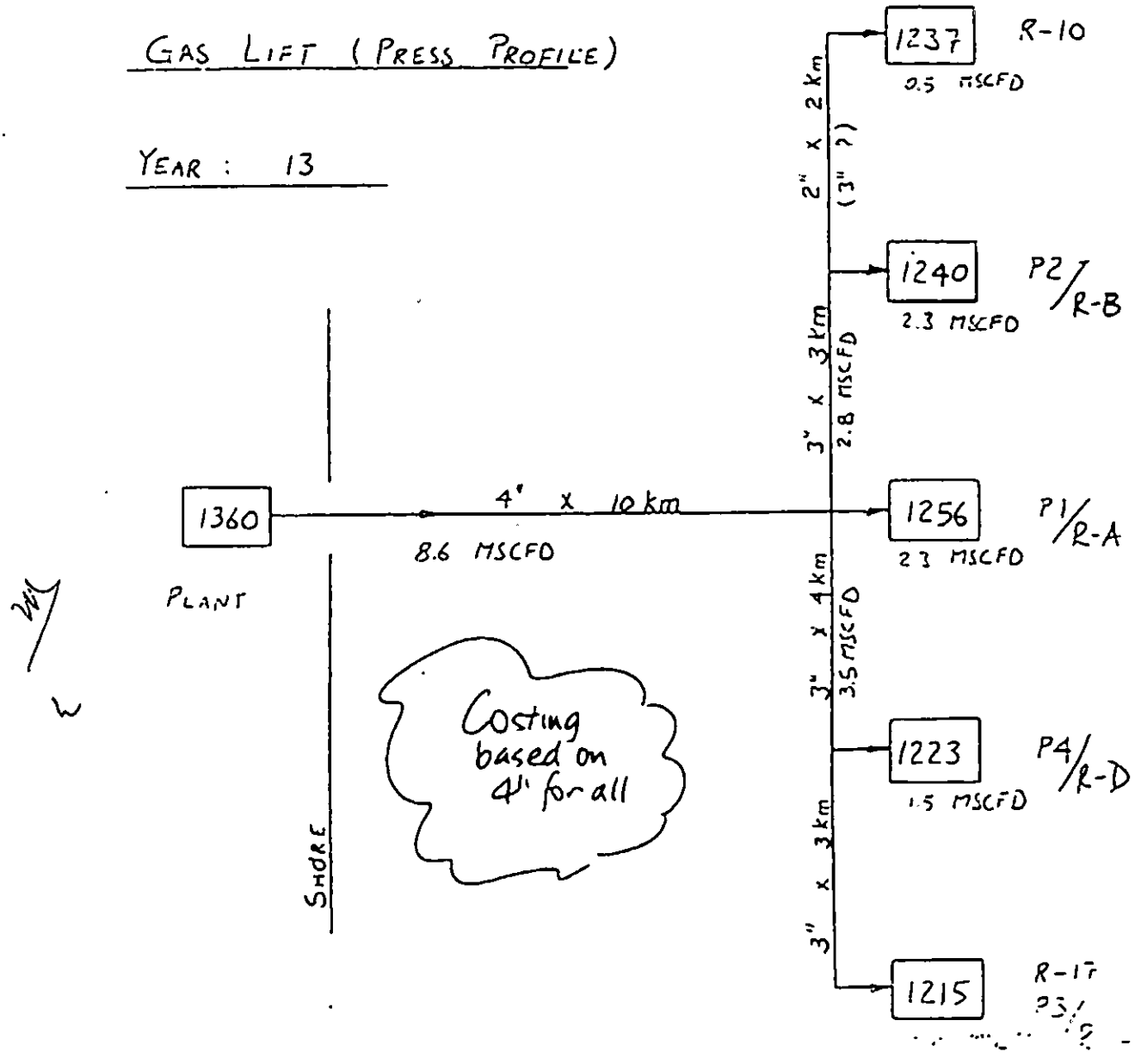
Note This would be the project, as further defined in the Development Plan, which would be the subject of the cost variation condition. The cost stated includes Import Duty but does not include expenditures related to exploration and appraisal or field abandonment. The difference between the US$218 million total and the estimated US$236 million total project capital cost quoted in Section I of the accompanying letter is the US$18 million abandonment cost

WORLEY ENGINEERING AUSTRALIA

Job No. 20192 Date 18 - 6 - 93
Client
Project RAVVA PRODUCTION SYSTEM
Subject LINE SIZING
Sheet ____ of ____ By S.V Check

GAS LIFT (PRESS PROFILE)

YEAR : 13



NOTES :

ALL PRESS. IN PSIA

PIPE LINE CLASS 600#

EXPERIENCE OF KEY PERSONNEL

HUGH WHITE, Operations Advisor, Command Petroleum Holdings N.L.

Mr. White has a total of 22 years active experience in the upstream oil business. In this time he has worked in Australia, U.K. sector of the North Sea and Malaysia, and has occupied positions from Drilling Engineer to General Manager.

Of particular relevance to the development of the Ravva Field is his experience in developing oilfields off the Northwest coast of Australia. In 1987 Mr. White managed the Airlie project which involved the development of two small oilfields in 18 metres of water and 25 km from the nearest land. Two small wellhead towers were designed and installed, a jack-up converted to a production platform, onshore storage built, and an offshore tanker loading facility installed. Production from the fields commenced within six months of obtaining project approval.

The success of the project resulted in a third field being developed and tied into the existing facilities, and the adoption of these techniques by other Operators developing small oilfields in this area.

SID FRENCH, Director, Worley Engineering

Mr. French has more than 20 years engineering experience which includes a Doctorate in structural analysis. His offshore experience ranges from field development and other feasibility studies through to project management of new designs and remedial works to existing facilities.

For the last several years he has been extensively involved in minimum cost field developments. He project managed the preliminary and detailed design phases of the Perch and Dolphin platforms - the first monotower structures in Bass Strait, Australia. These were the first gravity based monotowers and proved very cost effective. At the same time he was involved in pipeline cost reduction studies and other areas of cost minimisation for field developments.

Also during that period Mr. French has led teams carrying out feasibility studies for several other fields in Australia and offshore China. These have all followed the theme of structural simplicity, ease of fabrication and flexibility of installation. By applying a rigorous approach of minimising offshore process facilities, savings not only in installed cost but also ongoing offshore maintenance are achieved.

RICHARD WHILLAS, Engineering Manager, Worley Engineering

Mr. Whillas has 24 years experience which covers work in the offshore industry in the North Sea, South East Asia and Australia. As project manager for multidisciplinary teams he has lead feasibility studies and detailed designs for projects ranging up to major platforms such as BYR-A and BYB-A for Sarawak Shell Berhad. His years spent in Brunei and Malaysia have given him broad

experience in the scale and logistics of small field developments in areas remote from existing offshore infrastructure.

At present Mr. Whillas is carrying out feasibility work for a gas project offshore India as well as leading the team which has assisted BHPP in the Dai Hung development plans off Vietnam. With this ongoing involvement with offshore developments in shallow water areas and his regional experience Mr Whillas has the correct mix of skills to ensure that structural and process facilities are designed to suit the scale of the proposed development at Ravva.

HAL CORBOULD, Manager, Sydney Office, Worley Engineering

has over 20 years experience in the oil and gas industry, most of which has been with Esso in Australia and U.K. His last position in Australia with Esso was General Manger of the Bass Strait oil and gas production and processing facilities - producing 400 kb/d and 450 Mcf/d, with 1,200 staff.

Mr. Corbould has had a wealth of experience in planning the development of a wide range of oil and gas installations offshore and onshore, and is particularly familiar with cost reduction approaches to reduce initial and ongoing operating costs for oil and gas facilities. In the late 1980s Mr. Corbould managed the design, installation and drilling of unmanned facilities for Bass Strait which were similar to the additional facilities proposed for the Ravva Field

Mr. Corbould has previously had experience with design and contracting organisation, namely Bechtel and Fluor.

1. SCOPE OF WORK

1.1 Exploration

All data pertaining to the licence area will be collected and assimilated for the purposes of compiling a geological model and for identifying targets for exploration and appraisal drilling in subsequent years. The existing 2D and 3D seismic data will be reviewed, some re-processing trials conducted, and if thought appropriate, will be re-processed. Re-processing of seismic will be commenced in this year, and completed in the 1995/96 budget year

1.2 Development

Implementation of the Ravva Development Plan will be commenced. Preliminary engineering of all offshore and onshore facilities will be completed for the purposes of defining the facilities for tendering. Provision of all facilities is to be conducted under lump sum turnkey contracts, and these contracts will be awarded during the second calendar quarter of 1995, for installation during the 1995/96 weather window.

A thorough review of all geological and reservoir properties will be conducted with the objective of building a reservoir model to be used for simulation purposes. This model will be updated each time a well is drilled.

A review of all drilling data will be conducted in order to optimise the drilling and completion programmes.

To ensure efficient servicing of the offshore platforms it will be necessary to have fast boat access to the platforms from the site. To facilitate this, it will be necessary to have a jetty constructed adjacent to the pipeline landfall area. This jetty will be designed and constructed during the 1994/95 budget year.

1.3 Production

Command will assume the Operatorship of the Production Operations on the date of signing the PSC. During the first 90 days ONGC will continue to provide personnel and other services to assist Command during this period. ONGC will be reimbursed the costs incurred by them in providing this assistance.

Production from the existing wells will be maintained at 3,000 bopd (400 tonnes/day) and trucked to the refinery at Vishakhapatnam.

2. SUMMARY

	1994 US dollars
Exploration	560,000
Development	4,560,000
Production	2,540,000
Total Budget	**7,660,000**

Appendix G1

RAVVA OIL AND GAS FIELD

1994/95

WORK PROGRAMME AND BUDGET

for the period

November 1994 through March 1995

Command Petroleum (India) Pty Ltd

October 1994

WORK PROGRAMME AND BUDGET

November 1994 through March 1995

1. Scope of Work
2. Summary
3. Exploration
4. Development
5. Production
6. Forecast of Production
7. Security for Abandonment Costs
8. Total Monthly Budget

3. EXPLORATION

	TASK	DESCRIPTION	COST (millions 1994 US dollars)
3 1	Reprocess 2D and 3D seismic	Improvements in data processing techniques since the original processing indicates that the data set can be improved.	0.30
3 2	Geological and geophysical interpretation	Acquire and inventory existing data. Interpret original and reprocessed seismic, log, core, age and pressure data. Analyse data and create a geological model, integrated with seismic mapping. Evaluate potential exploration and appraisal well locations.	0 25
3.3	Drilling	No drilling is planned for the 1994/95 year.	-
3 4	Overheads		0.01
	Sub Total	**Exploration**	**0.56**

Note: Items 3 1 and 3.2 will not be completed in the 1994/95 year
Additional costs will be incurred by these tasks in 1995/96

4. DEVELOPMENT

TASK	DESCRIPTION	COST (millions 1994 US dollars)
Geological Studies	Interpretation of all geological and geophysical data. Preparation of geological model for hydrocarbon in place calculations and for input into simulation models. Commencement of preparation of development well locations.	0.34
Petroleum Engineering	Evaluate existing data. Conduct fluid and core analyses. Review well test data. Establish production data base and reporting system Evaluate sanding potential and remedies. Build and run reservoir simulation model.	0.49
Project Management	Management and supervision of project, including legal, tendering, accounting, contract negotiation and project execution.	0.65
Environmental Studies	Review previous environmental studies. Conduct baseline study. Prepare new EIS to reflect increased scope of development plan. Prepare Environmental Management Programme and Oil Spill Contingency Plan.	0.24
Jetty Construction	A jetty built adjacent to the pipeline landfall is required to allow efficient servicing of the offshore platforms. The site will be surveyed and, if suitable, tenders will be called for its construction.	1.10
Barge Mob/Demob	No offshore barges will be mobilised during the 1994/95 year.	
Tanker Mooring (SPM)	Design of, and identification of suitable location for, an SPM will be conducted. Allowance for additional geotechnical work is provided. A contract for the supply and installation of the mooring will be tendered and awarded.	0 17
Tanker Loading Line	Sizing and design of the line will be carried out. Particular emphasis will be placed on the design of pigging facilities in view of the high pour point crude.	0 15

TASK	DESCRIPTION	COST (millions 1994 US dollars)
Oil Platforms	Preliminary engineering will be carried out and a design document and scope of work prepared for tendering purposes. A contract for the detailed design, fabrication and installation of the platforms will be tendered and awarded. Allowance is included for additional geotechnical work.	0.27
Gas Platform	A design document and scope of work will be prepared for tendering purposes, and a contract for the detailed design, fabrication and installation will be tendered and awarded.	0.16
Flowlines	Sizing and design of oil and gas flowlines and water injection line will be carried out including determination of pigging requirements. Allowance is included for additional geotechnical work. A contract for the detailed design, procurement and installation of the flowlines will be tendered and awarded.	0.15
Onshore Oil Process	Design of an additional processing capacity for 40,000 barrels of oil per day will be conducted. A contract for the detailed design, fabrication and installation will be tendered and awarded.	0.13
Associated Gas Process	Preliminary design and engineering will be conducted for a plant to process the associated gas for sale. A contract for the detailed engineering, procurement, fabrication and installation will be awarded.	0.06
Non-Associated Gas Process	Preliminary engineering will be carried out. A contract for the detailed design, procurement, fabrication and installation of facilities to process the non-associated gas for sale will be tendered and awarded.	0.05
Water Injection	Preliminary design and engineering will be carried out, including analysis of available water supplies. A contract for the detailed design, fabrication and installation of these facilities will be tendered and awarded.	0.05
Onshore Oil Storage	Preliminary design of two 300,000 bbl floating-roof tanks will be conducted including, if necessary, geotechnical work for the design of foundations. A contract for the detailed design, fabrication and commissioning of the tanks, shipping pumps and onshore pipelines will be tendered and awarded.	0.10

TASK	DESCRIPTION	COST (millions 1994 US dollars
Drilling Development Wells	Review of past drilling records and preparation of drilling and completion programmes will be carried out. Orders for the purchase of long-lead items such as wellheads and tubulars may be placed.	0 40
Gas Wells	No gas wells will be drilled in 1994/95.	
Overheads		0.05
Sub Total	**Development**	**4.56**

5. PRODUCTION

ITEM		DESCRIPTION	COST (millions 1994 US dollars)
5.1	Madras Office	An office will be established in Madras. The funds include the cost of refurbishing an office and the cost of all labour and running costs.	1.06
5.2	Field Labour	Covers the cost of providing all labour, including accommodation, to operate the production facilities.	0.39
5.3	Helicopter	Covers the cost of chartering a helicopter on an "ad hoc" basis for the purpose of visits to the existing offshore platforms.	0.28
5.4	Service Vessel	It is envisaged that no service vessel will be utilised during this period. However, a contract will be awarded for a multi-purpose service vessel to commence operations in August 1995.	-
5.5	Repair and Maintenance	Covers the cost of carrying out repairs and maintenance to the existing offshore and onshore facilities.	0.21
5.6	Consumables	Covers the cost of chemicals, fuel and other items consumed during production operations	0.11
5.7	Insurance	Covers the cost of insuring the existing facilities and oil in store.	0.25
5.8	Reservoir Management	This function will be covered in the Sydney office by the Development team. Eventually, it will be transferred to the Madras office once personnel and facilities have been established there.	-
5.9	Wireline Surveys	It is proposed to conduct some wireline surveys in existing wells for the purposes of measuring reservoir pressure and evaluating the sand production potential of existing wells.	0.15
5.10	Environmental Protection	This will cover the cost of monitoring the operations and ensuring that they are in compliance with current environmental clearances.	0.03
5.11	Inspections	It is intended to inspect the existing offshore facilities to determine their condition and the presence of scouring around platforms and pipelines.	0.03
5.12	Overheads		0.03
	Sub Total	Production	2.54

6. FORECAST OF PRODUCTION

Year	Month	Daily Rate (barrels)	Monthly Rate (tonnes)	Cumulative (tonnes)
	November	3,000	11,550	11,550
	December	3,000	11,940	23,490
1995	January	3,000	11,940	35,430
	February	3,000	10,780	46,210
	March	3,000	11,940	58,150

Note: Crude oil density assumed to be 7.4 barrels per tonne.

7. SECURITY FOR ABANDONMENT COSTS

Schedule of Annual Production and Provision for Abandonment Costs

YEAR	PRODUCTION (millions of bbls)	ABANDONMENT COSTS (US dollars)
1994	0.06	12,000
1995	1.88	373,000
1996	12.78	2,537,000
1997	12.78	2,537,000
1998	12.78	2,537,000
1999	12.78	2,537,000
2000	12.78	2,537,000
2001	12.02	2,386,000
2002	8.12	1,612,000
2003	5.22	1,036,000
2004	2.97	590,000
2005	2.16	429,000
2006	1 70	337,000
2007	1.14	226,000
2008	0.82	163,000
2009	0 48	95,000
2010	0.28	56,000
TOTAL	100.75	20,000,000

Comme ... Petroleum Holdings Pt

RAVVA OIL AND GAS FIELD DEVELOPMENT

		CATEGORY	NOVEMBER 94	DECEMBER 94	JANUARY 95	FEBRUARY 95	MARCH 95	SUB TOTAL 94/95
EXPLORATION	Reprocess seismic	Firm		0.15		0.15		0.30
	Geological review	Firm	0.07	0.04	0.05	0.04	0.05	0.25
	Drill Exploration/Appraisal Wells	To mature						0.00
	Overheads @	1.9%	0.00	0.00	0.00	0.00	0.00	0.01
	Sub Total - Exploration		0.07	0.19	0.05	0.19	0.05	0.56
DEVELOPMENT	Geological Studies	Firm	0.10	0.08	0.08	0.08	0.08	0.34
	Petroleum Engineering	Firm	0.13	0.08	0.08	0.08	0.08	0.45
	Project Management	Firm	0.24	0.11	0.10	0.10	0.10	0.65
	Environmental Studies	Firm	0.01	0.07	0.07	0.07	0.02	0.24
	Jetty Construction	Firm	0.01	0.25	0.09	0.25	0.30	1.10
	Barge Maintenance	Firm						0.00
	Tanker Mooring (SPM)	Firm	0.08	0.11				0.17
	Tanker Loading Line	Firm	0.05	0.10				0.15
	Oil Platforms	Firm	0.17	0.10				0.27
	Gas Platform	Firm	0.03	0.11	0.02			0.16
	Flowlines	Firm	0.05	0.10				0.15
	Onshore Oil Process	Firm	0.03	0.05	0.03			0.13
	Associated Gas Process	Firm	0.01	0.03	0.02			0.06
	Non-associated Gas Process	Firm		0.03	0.02			0.05
	Water Injection	Firm	0.05					0.05
	Onshore Oil Storage	Firm	0.05	0.02	0.03			0.10
	Drill Oil Production/Injection Wells	Firm	0.08	0.08	0.08	0.08	0.08	0.40
	Drill Gas Wells	Firm						0.00
	Overheads @	1.9%	0.01	0.01	0.01	0.01	0.01	0.05
	Sub Total - Development		1.10	1.53	0.82	0.88	0.68	4.56
PRODUCTION	Marine Office	Firm	0.33	0.23	0.20	0.13	0.13	1.06
	Field Labour	Firm	0.11	0.07	0.01	0.07	0.07	0.39
	Helicopter	Firm	0.06	0.06	0.05	0.06	0.06	0.28
	Service Vessel	Firm						0.00
	Repair and Maintenance	Firm	0.05	0.04	0.04	0.04	0.04	0.21
	Consumables	Firm	0.03	0.02	0.02	0.02	0.02	0.11
	Insurance	Firm	0.25					0.25
	Reservoir Management	Firm						0.00
	Welsite Surveys	Firm	0.05		0.05		0.05	0.15
	Environmental Protection	Firm	0.01	0.01		0.01		0.03
	Inspections	Firm	0.01		0.01		0.01	0.03
	Overheads @	1.9%	0.01	0.00	0.00	0.00	0.00	0.01
	Sub Total - Production		0.92	0.43	0.48	0.33	0.37	2.54
TOTAL COSTS	(UNESCALATED)		2.10	1.94	1.15	1.17	1.26	7.65

Appendix G2

RAVVA OIL AND GAS FIELD

1995/96

WORK PROGRAMME AND BUDGET

for the period

April 1995 through March 1996

Command Petroleum (India) Pty Ltd October 1994

WORK PROGRAMME AND BUDGET

April 1995 through March 1996

1. Scope of Work

2. Summary

3. Exploration

4. Development

5. Production

6. Forecast of Production

7. Security for Abandonment Costs

8. Monthly Budget Schedule

1. SCOPE OF WORK

1.1 Exploration

Interpretation of re-processed seismic and preparation of a geological model (commenced in 1994/95) will be completed. To ensure that the first phase of exploration/appraisal drilling is completed as per the committment and without interfering with development drilling, it may be necessary to bring forward the exploration/appraisal programme. Exploration work will, therefore, be focused on identifying suitable locations for the drilling of these wells.

In order to get additional core and fluid data, and for Command to become familiar with drilling conditions prior to commencement of the development drilling programme, consideration will be given to an Early Drilling Programme commencing in the third calendar quarter, 1995.

1.2 Development

During the year the implementation of the Ravva Development Plan will be completed. At this time it is not intended to install the gas lift facilities; however consideration will be given to installing them with the other facilities if it can be demonstrated to be cost effective to do so. All offshore and onshore facilities will be installed and commissioned, and production rates will, dependent on the number of wells actually completed, increase and, by the end of the budget year, will be approaching the target rate of 35,000 barrels of oil per day. In addition, it is intended that, subject to negotiation of a mutually agreeable sales contract, gas processing facilities will be installed and that, after drilling of some gas production wells, gas sales will commence in June 1996.

1.3 Production

Until the additional offshore and onshore facilities have been installed (and in particular the offshore tanker loading facilities) production from the field will remain at 3,000 bopd (400 tonnes/day) with all production being trucked to the refinery at Vishakhapatnam.

During this time, focus will be on maintaining the existing facilities, training of personnel for the new facilities and implementing procedures that will ensure their safe and efficient operation.

2. SUMMARY

1995/96 Budget Year

	1994 US dollars
Exploration	9,970,000
Development	147,070,000
Production	5,570,000
Total Budget	162,610,000

3. EXPLORATION

	TASK	DESCRIPTION	COST (millions 1994 $US)
3.1	Reprocessing Seismic	Re-processing of all 2D and 3D seismic (initiated in 1994/95).	0.33
3.2	Geological Review	Interpretation of seismic and compilation of a geological model for the Ravva field and surrounding area will be completed.	0.54
3.3	Drilling	Three exploration/appraisal wells will be drilled during the year to partially meet a commitment to drill six exploration/ appraisal wells in the second licence year.	9.00
3.4	Overheads		0.10
	Sub Total	**Exploration**	**9.97**

4. DEVELOPMENT

	TASK	DESCRIPTION	COST (millions 1994 $US)
4.1	Geological Studies	The work implemented in 1994/95 will be completed and results from the drilling of appraisal and development wells will be incorporated into the geological model of the Ravva field.	0.72
4.2	Petroleum Engineering	The preparation of a reservoir model for simulation purposes will be completed and the results of drilling will be incorporated into it. Conduct of well tests and analysis of new core material will be carried out.	0.96
4.3	Project Management	Covers the cost of managing the project including the execution and supervision of all contracts. Included in this cost is the cost of insuring the development works ($2.16m).	3.36
4.4	Environmental Studies	The budget assumes that some environmental studies, commenced in the 1994/95 year will be carried over into the 1995/96 year.	0.10-
4.5	Jetty Construction	The budget assumes that the jetty construction is completed in 1994/95.	-
4.6	Barge Mob/Demob	Covers the cost of mobilising and demobilising offshore construction vessels.	3.52
4.7	Tanker Mooring (SPM)	Covers the cost of procuring and installing an SPM, rated for 120,000 DWT tankers in 20 to 25 metres of water.	9.11

	TASK	DESCRIPTION	COST (millions 1994 $US)
4.8	Tanker Loading Line	Covers the cost of installing a loading line of sufficient capacity to allow loading of crude oil at a rate of 30,000 bbls per hour.	9.43
4.9	Oil Platforms	Covers the cost of fabrication and installation of four platforms complete with topsides containing well test facilities.	33.78
4.10	Gas Platform	Covers the cost of fabrication and installation of a three well gas platform in 12 metres of water close to the R-9 well location.	2.75
4.11	Flowlines	Covers the cost of installing oil and gas production lines and water injection lines.	21.82
4.12	Onshore Oil Process	Covers the cost of fabricating and installing a crude stabilisation unit with capacity of 40,000 bopd.	4.42
4.13	Associated Gas Process	Covers the cost of installing a facility which will process associated gas for sale, including compression.	6.96
4.14	Non-Associated Gas Process	Covers the cost of processing non-associated gas for sales purposes.	1.84
4.15	Water Injection	Covers the cost of fabricating and installing facilities for the injection of water into the reservoir for the purpose of pressure maintenance.	3.83

	TASK	DESCRIPTION	COST (millions 1994 $US)
4.16	Onshore Oil Storage	Two 300,000 barrel capacity floating roof storage tanks will be constructed and installed. Costs include pumps and onshore pipelines.	23.24
4.17	Drilling Development Wells	Costs assume that one development well is drilled and completed from the existing R-10 platform and that 12 wells are drilled through templates and completed after installation of the platforms.	19.77
4.18	Drilling Gas Wells	Drilling of gas wells will take place in the 1996/97 budget year.	-
4.19	Overheads		1.46
	Sub Total	**Development**	**147.07**

5. PRODUCTION

	ITEM	DESCRIPTION	COST (millions 1994 $US)
5.1	Madras Office	Cost to maintain Madras office including salaries and labour and all running costs.	1.80
5.2	Field Labour	Cost of manning the production facilities.	0.84
5.3	Helicopter	Cost of hiring a helicopter on an "ad hoc" basis. The drilling operation will have a dedicated helicopter from July and it is proposed that the production operations will use this aircraft.	0.60
5.4	Service Vessel	It is proposed that the purpose built service vessel will be in service by August 1995. Cost allows for the hire of vessel, crew and fuel.	0.88
5.5	Repair and Maintenance	Covers cost of repairing and maintaining existing facilities.	0.51
5.6	Consumables	Covers the cost of chemicals, fuel and other items required to keep the plant running.	0.47
5.7	Insurance	Covers the cost of re-insuring the existing facilities.	0.25
5.8	Reservoir Management	This function will continue to be managed in Sydney although some reservoir/production personnel will be employed in the Madras office.	-

	ITEM	DESCRIPTION	COST (millions 1994 $US)
5.9	Wireline Surveys	Some additional surveys of existing wells will be run for reservoir management purposes. Once drilling of new wells starts, no further wireline surveys are planned during the year.	0.10
5.10	Environmental Protection	Covers cost of monitoring operations and ensuring compliance with environmental clearances.	0.06
5.11	Inspections	No inspections are planned for this year.	-
5.12	Overheads		0.06
	Sub Total	**Production**	**5.57**

6. FORECAST OF PRODUCTION

Year	Month	Daily Rate (barrels)	Monthly Rate (tonnes)	Cumulative (tonnes)
1995	April	3,000	11,550	11,550
	May	3,000	11,940	23,490
	June	3,000	11,550	35,040
	July	3,000	11,940	46,980
	August	3,000	11,940	58,920
	September	3,000	11,550	70,470
	October	3,000	11,940	82,410
	November	3,000	11,550	93,960
	December	3,000	11,940	105,900
1996	January	3,000	11,940	117,840
	February	9,000	33,500	151,340
	March	26,000	103,500	254,840

Note: Crude oil density assumed to be 7.4 barrels per tonne.

7. SECURITY FOR ABANDONMENT COSTS

Schedule of Annual Production and Provision for Abandonment Costs

YEAR	PRODUCTION (millions of bbls)	ABANDONMENT COSTS (US dollars)
1994	0.60	119,000
1995	1.88	373,000
1996	12.78	2,537,000
1997	12.78	2,537,000
1998	12.78	2,537,000
1999	12.78	2,537,000
2000	12.78	2,537,000
2001	11.48	2,279,000
2002	8.12	1,612,000
2003	5.22	1,036,000
2004	2.97	590,000
2005	2.16	429,000
2006	1.70	337,000
2007	1.14	226,000
2008	0.82	163,000
2009	0.48	95,000
2010	0.28	56,000
TOTAL	100.75	20,000,000

$ TOTAL MONTHLY BUDGET

		CATEGORY	APRIL 94	MAY 94	JUNE 94	JULY 94	AUGUST 94	SEPTEMBER 94	OCTOBER 94	NOVEMBER 94	DECEMBER 94	JANUARY 95	FEBRUARY 95	MARCH 95	SUB TOTAL 94/95
EXPLORATION															
	[illegible]	Firm	0.15		0.18										0.33
	[illegible]	Firm	0.03	0.01	0.03	0.01	0.05	0.04	0.05	0.04	0.05	0.01	0.01	0.01	0.34
	Drill Exploration/Appraisal Wells	Tentative				3.00		3.00	3.00						9.00
	Overheads @	1.0%	0.00	0.00	0.00	0.03	0.00	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.16
	Sub Total - Exploration		0.20	0.01	0.21	3.07	0.05	3.07	3.08	0.04	0.05	0.01	0.01	0.01	9.83
DEVELOPMENT															
	Pre Effective Date Engineering	Firm													0.00
	[illegible]	Firm	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.72
	[illegible]	Firm	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.96
	[illegible]	Firm	0.10	0.10	0.10	2.20	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	3.30
	[illegible]	Firm	0.02	0.02	0.02	0.02	0.02								0.10
	Jetty Construction	Firm													0.00
	[illegible]	Firm									3.57				3.57
	[illegible]	Firm									0.11				0.11
	[illegible]	Firm									0.43				0.43
	[illegible]	Firm										33.76			33.76
	[illegible]	Firm										2.75			2.75
	[illegible]	Firm											31.42		31.42
	[illegible]	Firm									4.42				4.42
	[illegible]	Firm										8.96			8.96
	[illegible]	Firm									1.04				1.04
	[illegible]	Firm									3.83				3.83
	[illegible]	Firm									23.24				23.24
	[illegible]	Firm	0.04	0.04	0.04	0.04	3.00	0.04	0.04	3.24	3.24	3.24	3.24	3.24	18.72
	[illegible]	Firm													0.00
	Overheads @	1.0%	0.00	0.00	0.00	0.03	0.03	0.00	0.00	0.03	0.39	0.47	0.25	0.03	1.46
	Sub Total - Development		0.34	0.34	0.34	2.53	3.36	0.32	0.32	3.51	39.48	49.61	35.53	3.51	141.07
PRODUCTION															
	[illegible]	Firm	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.80
	[illegible]	Firm	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.84
	[illegible]	Firm	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.60
	[illegible]	Firm				0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.66
	[illegible]	Firm	0.04	0.01	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.31
	[illegible]	Firm	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.01	0.37
	Insurance	Firm					0.20								0.20
	[illegible]	Firm													0.00
	Wildlife Surveys	Firm		0.05		0.06									0.10
	Environmental Protection	Firm	0.01		0.01		0.01		0.01		0.01		0.01		0.06
	Inspections	Firm													0.00
	Overheads @	1.0%	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01
	Sub Total - Production		0.35	0.39	0.39	0.50	0.67	0.72	0.47	0.46	0.47	0.46	0.45	0.43	5.97
TOTAL COSTS	(UNESCALATED)		0.90	0.78	0.93	5.90	5.11	4.11	3.86	4.07	39.99	17.96	29.18	4.87	162.96

APPENDIX H
(Article 8.4)

PROCEDURES FOR ACQUISITION OF GOODS AND SERVICES

1. Objectives

The objectives of these procedures are to:

(a) Ensure that the goods and services acquired by the Operator for the carrying out of Petroleum Operations are acquired at the optimum cost taking into consideration all relevant factors including price, quality, timing of delivery and the reliability of potential suppliers.

(b) Ensure that goods and services are delivered in a timely manner taking into consideration the consequences on the project as a whole of delays in the acquisition of these goods and services.

(c) Ensure that the provisions of Article 24 of the Contract are implemented.

2. **Principles**

The principles upon which these procedures are based are:

(a) The Parties must be satisfied that the Operator is working to an agreed procedure for acquiring goods and services that is auditable and in accordance with the provisions of the Contract.

(b) The Operator must have the ability to acquire goods and services expeditiously so that the project schedules in respect of Approved Work Programmes are maintained.

3. **Procedures**

The procedures to be adopted by the Operator for the acquisition of goods and services shall be as follows:

(a) For contracts valued at less than US$25,000

The Operator will be at liberty to determine the preferred method of acquiring goods and services valued at less than US$25,000 with the understanding that at least three (3) quotations from selected suppliers (including at least one (1) Indian supplier) will be obtained. For items valued at greater than US$10,000, Operator is required to report to the Operating Committee if the quote accepted exceeds the lowest quote by more than 20 percent. Operator will promptly report to the

Operating Committee the Operator's reasons for not selecting the lowest quote.

(b) For contracts valued at between US$25,000 and US$500,000

Tenders will be requested from at least three (3) suppliers (including at least one (1) Indian supplier) who will bid against a tender document prepared by the Operator. An award will be made by the Operator on the basis of the best price/delivery/quality mix. The Operator will seek Operating Committee approval if it wishes to accept a tender other than the lowest price tender.

(c) For contracts valued in excess of US$500,000

The Operator shall distribute a list of suitably qualified suppliers to the other Parties at least 21 days prior to the date on which the Operator proposes to seek tenders, together with the Operator's justification for the inclusion of the nominated suppliers on the list. The Operator shall, at the same time, advertise its intention to seek such tender in at least one national Indian newspaper. Any Party may, within 10 days of receipt of such list, submit the names of other suitably qualified suppliers to the Operator and the other Parties, together with such Party's justification for the inclusion of such supplier.

The Operator shall compile a final list of suitably qualified suppliers ("the Final List") and distribute same to all Parties within 7 days of the expiration of the aforesaid 10 day period together with the reasons for including or excluding any supplier nominated by any of the other Parties.

Invitations to tender will be issued to the suppliers included in the Final List. Tenders received by the due date will be analysed by the Operator and a recommendation made to the Parties.

Such recommendation will be accompanied by a summary table of the suppliers invited to tender and the essential elements of their bids including price, equipment/service offered, delivery schedule, and any remarks which the Operator deems pertinent to the bid. Operator's analysis of the bids will be attached and will address such matters as cost versus budget, impact on schedule, and reasons for recommending a preferred bidder including reasons for the lowest bidder not being recommended as the preferred bidder where such is the case. Operator shall also attach a summary of its efforts to comply with Article 24.

Any queries by a Party in relation to Operator's recommendation shall be notified to Operator within ten (10) days of receipt of same and Operator shall promptly reply.

The Operating Committee shall vote in relation to the Operator's recommendation within fourteen '14' days of receipt of such recommendation. Such a vote shall be by telex or facsimile transmission and no Party shall be entitled to call for a meeting of the Management Committee in respect of such recommendation notwithstanding the provisions of Article 6.17(b)(ii).

(c) General

The tendering process will consist of only one stage. Consequently bidders will be required to submit both technical and commercial details with their bid. During the evaluation process the Operator will hold any necessary discussions with tenders for the purpose of clarifying a tender's bid.

4. **Authorities**

Authority of the Operator to award contracts will be as follows:

Estimated Cost US$	Tendering	Operating Committee Approval
0-25,000	No	No
25,000-500,000	Yes	No
Over 500,000	Yes	Yes

5. **Use of Local Goods and Services**

The Operator recognises the benefit of using local suppliers in accordance with Article 24. To this end every opportunity will be taken to utilise local suppliers wherever possible.

6. **Operator to Contract as Agent, Audit Rights and Assignability**

(a) The Operator shall act as an agent of the Parties in dealings with contractors and suppliers.

(b) Unless otherwise determined by the Management Committee, in negotiating contracts with third parties in excess of US$10,000, Operator shall procure the right to audit clause.

(c) Unless otherwise approved by the Management Committee, the Operator shall ensure that any

contract awarded may be freely assigned to any successor of the Operator in the event of resignation or removal of the Operator.