BLUELAKE ENERGY

Commentary on proposed Rajasthan Developments by Cairn Energy

Prepared for

National Australia Bank

CONTENTS

Summary and Conclusion

Cairn Energy Summary and Conclusion

Summary - Our Objectives in this Analysis

- The focus of this report is to look at the proposed development of Cairn's Rajasthan assets (Mangala, Ashwariyia, Saraswati Raggeshwari).
- Since Mangala represents the core of the Cairn assets (and Ashwariya is virtually identical geologically) – we have concentrated on the Mangala asset in this document.
- We will offer additional more detailed commentary on the other reserves at a later stage if necessary, although it is the opinion of Hulf Hamilton that reserves and reservoir performance are less critical than the proposed development schedule itself.
- Mangala (the main Rajasthan field) was the largest oil field discovered in the world in 2004 (428 million barrels gross[1]) with similar world class reservoir performance.
- We have assessed Cairn's overall assumptions and the likelihood of keeping within budgeted cost and time to first oil Q4 2008 for the 4 Rajasthan fields in the Borrowing Base Mangala.
- We have focused particularly on the reasonablessnes of the Cairn Field Development Plans (FDP's) and Transportation Plans.
- Based on the above, we have assessed the potential for project slippage (time and cost).
- We have commented on the reasonableness of Cairn's assessment that the Mangala to Mundra pipeline may be delayed and the ability of Cairn to scale down the development and associated processing facility; such that the project would only produce 35,000boepd (for an interim period) which would loaded onto train wagons for shipment to the port, with development recommencing to reach a production target of 150,000 boepd to be ready to come on line when the pipeline is finished.
- In the appendices we also cover similar ground for the Aishwariya field (48MMbbl Gross 2P).
- Aishwariya is a virtually identical structure to Mangala but further south and Cairn has used reasonable assumptions in its proposed development programme.
- It has less 'sandy' reservoir units to Mangala but where it is present productivity is similar to Mangala but this is why reserves are smaller, despite the top surface maps appearing similar.

Conclusion

- The main assumptions used by Cairn in planning the development of Mangala and surrounding fields is based on a substantial appraisal effort since the discovery of Mangala in January 2004 and this includes:
  - Detailed production/logging/reservoir and fluid sampling from appraisal wells
  - Independent studies of aquifer and water injectivity requirements
  - Independent studies on pipeline routing
  - Laboratory studies on core and fluid samples
  - Live well testing of water injectivity

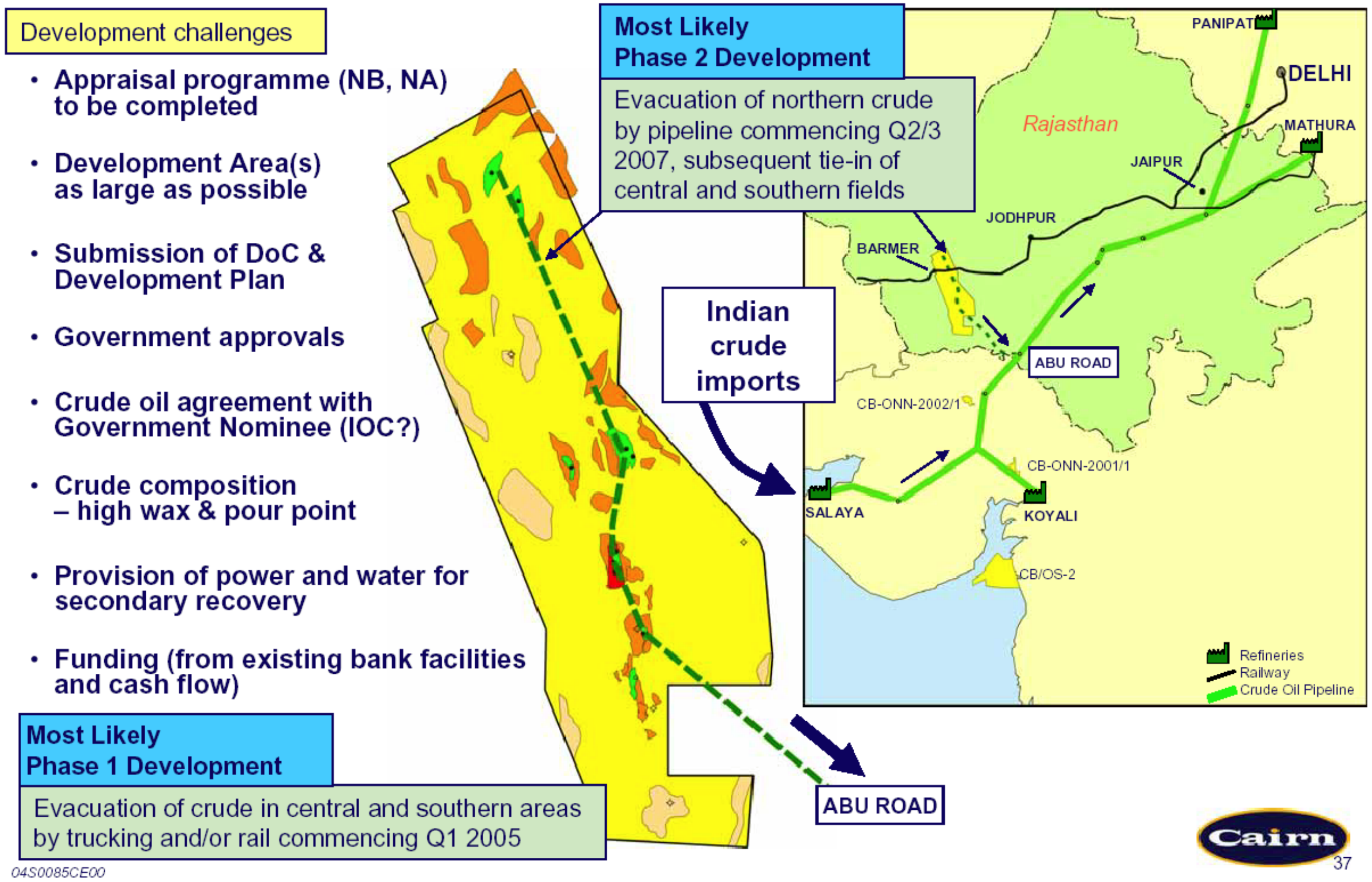
  It is our opinion that Cairn has at least met the standard requirements of field development and planning usually performed by oil companies.
- We have analyzed the likely productivity of individual wells, factoring in the heavier more waxy crude from Mangala and have found the basic prediction of a 100,000b/d gross oil production plateau to be reasonable and achievable[2].
- A similar analysis was performed on Aishwariya.
- More specifically on capital expenditures Cairn predicts gross capital expenditures of $1247MM for the 368MMbbl 2P reserves case ($3.61/bbl) and this compares to a global average of ($3.00/bbl). We think the Cairn estimate is reasonable because the higher value reflects the additional expenditure on the treatment and handling of waxy crude and reservoir pressure maintenance.
- Operating costs in India are low and this has already been proven by Cairn's Indian track record of less than $1.6/boe so the $2.75/bbl prediction for Mangala appears reasonable to us as this reflects the more substantial development including the additional handling of large water volumes as part of the operation.
- The greatest area of uncertainty in the project (and the largest portion of capex – 36%) is in development drilling. We have run sensitivities on higher material costs for drilling and longer drilling times and have found that capex on drilling could increase from $443 to $486MM with an overall 20% increase in drilling time.
- The scope for slippage[3] on surface facilities is less in our opinion owing to the standard and modular nature of hydrocarbon processing equipment.
- We finally conclude that if Cairn needed to slow down the development (to initial 35,000b/d gross production), it could do so by slowing up the drilling programme but would most likely install the main processing facilities anyway for full utilization later.

---

[1] Latest Cairn estimate at 10 April 2006 based on production to 2041.
[2] Assuming there are no delays to the export facilities beyond the Cairn custody transfer to the Government of India at the Processing Facility output flange.
[3] We only comment on the technical elements of the project – commercial (ordering) and legal factors are beyond the scope of this report.

Barmer Basin Development Overview Challenges

Development Options



Source Cairn Energy 2003 final results presentation.

Commentary

- Cairn summarized the key challenges of operations in Rajasthan to Equity Analysts in 2003.
- This tells us that Cairn has been studying the challenges carefully for at least the last 3 years.
- Currently produced oil from Saraswati is being trucked by road.
- A pipeline development is planned.
- The pipeline will be paid for 100% by the Indian government.
- In this document we aim to address each of the points made by Cairn on the left, as a basis for lending against the assets.

Barmer Basin Top Surface Challenges

Rajasthan Desert

Cairn Nearby Processing Plant

Source: Hulf Hamilton Photo

Commentary

Production Facility

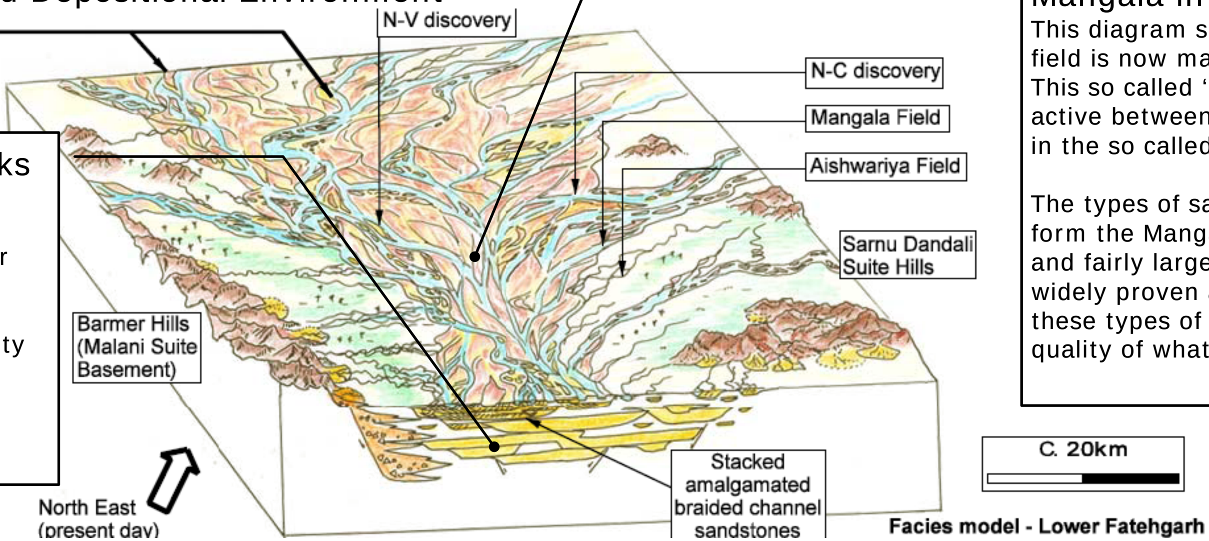
- Hulf Hamilton Visited Rajasthan in November 2005.
- Part of the tour took us from Bhagyam drilling to the Mangala-1 drilling site and the location of the processing plant.
- Oil from Bhagyam, Mangala, and Ashwariya will be processed in a new 200,000b/d plant close to the Mangala field.
- The exact location is shown in the top left photograph taken on the trip.
- The lower photo shows the Lakshmi processing plant and the Mangala plant will have an oil processing capability many times the size of this.
- From our analysis about a half of Cairns' core value is in the Mangala field so the timing and cost of the development are critical such as
  - first oil (scheduled for 2007/2008)
  - Project costs
  - Operating costs
  - Plateau production
- We address each of these points in this document.

Conclusion: We can reconcile Cairns track record of very low unit opex in India (<$1/boe) to Mangala opex, and we would expect unit capex to be relatively high with substantial water injection planned and infield pipelines.

Rajasthan Geological Overview

Channel Sands Dominate Subsurface Characteristics

Channel Sand Depositional Environment



Channel Stacks

Over time the channels stack on top of one another to form the reservoir. The vertical connectivity of these channels governs reservoir performance and this is key

Mangala in prehistoric times

This diagram shows how the area where the Mangala field is now may have looked in prehistoric times. This so called 'braided river' was thought to be active between 37million and 65 million years ago – in the so called Eocene-Paleocene era.

The types of sand particles laid down then that now form the Mangala reservoir are clean, well sorted and fairly large in granular size. This theory is widely proven and now a standard interpretation of these types of sands. This has led to the excellent quality of what is now known as 'Fatehgarh sands'.

Source: Cairn Energy

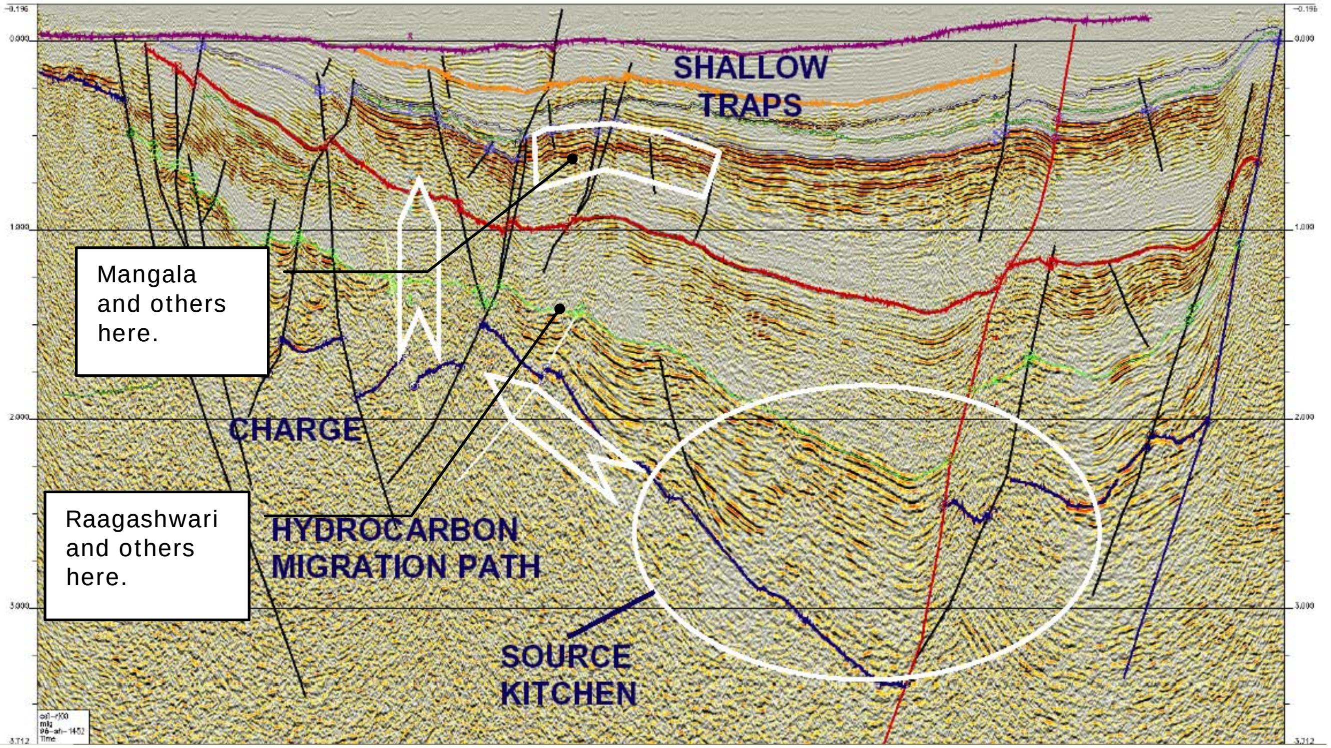
Commentary

- The Cairn borrowing base facility is based on the Cairn portfolio of discovered oil fields in Rajasthan, West India; in turn dominated by a single asset – the Mangala oil field.
- The nature of the cash flows from this field is dominated by the distinct reservoir characteristics of:
  - Shallow reservoir, hence with lower pressure (energy).
  - Slightly heavy (thicker) oil, due to the shallow depth.
  - World class reservoir quality leading to very high potential flow rates.
  - Reservoir made up of ancient channel sands.
- The mitigants to the shallow depth of the field are as follows:
  - Shallow depth makes drilling wells cheaper.
  - Pressure can be maintained by injecting water to replace produced oil
  - Heated water overcomes the heavy characteristics of the oil.
  - Many wells have already been drilled to generate a large data set.
  - The dataset has led to the creation of a detailed computer simulation.
  - The computer simulation has been used to estimate field performance.
- Subsurface areas where project backers should be mindful are:
  - Monitoring the spending on water injection facilities.
  - Monitoring spending on handling of heavier oil.
  - Monitoring the predictions of computer simulation vs. actual production.
  - Monitoring sand production from the high quality reservoir (damaging).
- Although we may be able to predict reserves, future production may be uncertain because of the presence of channel sand reservoirs.
- Channel sands are not always connected and are sometimes the direction is difficult to predict.
- This will explain the relatively high number of wells (160) on the Mangala development, but as each well is relatively cheap to drill ($1.5MM),

Conclusion: There are plus and minus points for channel sand systems in petroleum geology. In our opinion Cairn has taken all reasonable steps to predict the performance of the channel sand based reservoir through analysis of drilling data and computer simulation and therefore the basis of Cairns predictions for reservoir performance appear reasonable.

Rajasthan Basin Setting

Seismic Cross Section across northern part of Rajasthan Basin



Source: Cairn energy, Rajasthan update, Feb 2003

Commentary

- If we take a slice through the Barmer Basin from North to South and look in at the side; the diagram left is what we see.
- The Northern field of Mangala and others are found in the shallow traps shown left in the good quality Fatehgarh reservoir.
- Excellent quality source rock is proven across the basin.
- Although oil seems not to have migrated much further than Mangala to the north.
- The problem with being shallow (3000ft for Mangala), is that pressures are lower (1400psi).
- Low pressure generally means less energy and lower recovery factors but the better quality reservoir compensates for this to some degree.
- Future production rates will therefore rely heavily in the Operator putting energy into the reservoir with water and gas injection.

Conclusion: Water injection into complex channel sands to maintain pressure and production may be an uncertain business. Cairn has minimized this uncertainty with extensive appraisal drilling, reservoir studies and ultimately reservoir simulation to mitigate these risk factors.

Reserves and Recovery Factors

Mangala Reserves Summary

Fatehgarh Reservoir	Input Parameters		
	P90	P50	P10
GRV MMm3 [1]	1688	2018	2328
N/G [2]	0.401	0.465	0.53
Porosity	0.222	0.239	0.257
So [3]	0.765	0.833	0.905
FVF	1.06	1.1	1.14

	Output Results			
	Proven		2P	3P
	P90	P70	P50	P10
STOIIP(MMbbls)	**819**	**941**	**1071**	**1336**

1: Uncertainty due to seismic resolution, position of bounding fault, depth conversion and OWC location
2: Uncertainty of fluvial sand bodies
3: Uncertainties of 'oil wet' reservoir associated with high permeabilities

	Cairn 2020 (MMbbl)	D&M 2025 (MMbbl)	Cairn 2041 (MMbbl)
2P Reserves (MMbbl)	271	338	368
Recovery Factor	25%	32%	34%
	1P 2041 (MMbbl)	**2P 2041 (MMbbl)**	**3P 2041 (MMbbl)**
Cairn	289	368	480
No Wells	164	160	184
Recovery per well	1.8	2.3	2.6

Reserve Commentary

Proven + Probable (2P) reserves

- The Cairn 2p (368MMbbl) gross recovery from Mangala equates to a 34% recovery factor.
- This recovery rate is predicated on:
  1) - the volume of oil in place
  2) - water injection to maintain pressure
  3) - the use of 'jet pumps' to increase suction.
- The volume of oil in place is affected by 3 uncertainties as described left.
- The items 2) and 3) above rely to a relatively large degree on the results from a Simulation Model of the Mangala reservoir

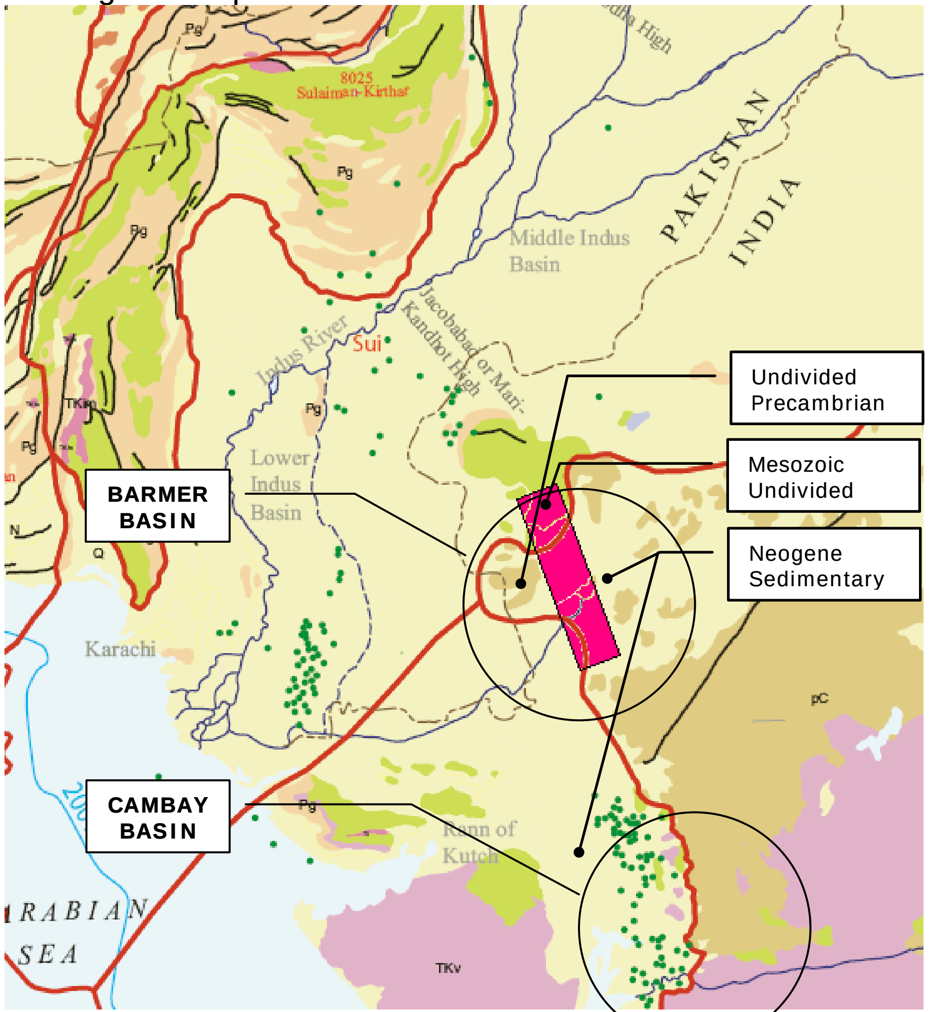
Simulation Model Commentary

- The initial geological model was created from the 3D seismic data and contained 341 'layers'.
- The 'layers' are mathematical 'cubes' that define the physical characteristics of the subsurface in a mathematical definition.
- The geo physical model was converted to a reservoir simulation model of 87 layers.
- The reservoir simulation introduces the representation of fluids in the reservoir by mathematically modeling pressure, temperature and fluid flow.
- Cairn has taken as many physical measurements from well data and crude/water/gas samples, as possible, to simulate as true to life as possible the predicted performance of the reservoir.
- Future modifications to the model will be required as new data emerges from the field (history matching), and this is standard practice in reservoir engineering.
- There are always limitations in reservoir modeling but Cairn has followed industry practice in preparing the model and has done so from a relatively high data base of physical well data.

Conclusion: Cairn has made reasonable estimates of 2P reserves based on sophisticated reservoir simulation work and the 368MMbbl 2P value compares well to the D&M 338MMbbl value. We would always expect the third party audit (D&M) to be more cautious and conservative than the operator number but in this case it is relatively close, indicating that Cairn appears to have been cautious in its approach.

Recovery Factor analogy

Geological map



Source: US Geological Survey

Commentary

Introduction

- We are interested in the analogy between the Cambay basin and the Barmer basin for the purposes of predicting production levels.
- The diagram left shows the geological environment across western India.
- We have shown the approximate location of Cairn license RJ-ON-01 in pink.

Similarities

- On initial examination the Barmer and Cambay are not in the same geological areas
  - Cambay in Bombay Basin
  - Barmer partly in the Indus, Indian shield and Bombay basins.
- But there are sedimentary similarities in the Neogene (this means the age and depositional environment of the sandstones is the same and therefore reservoir properties may be similar).
- We are satisfied that analogies between the two basins are appropriate.

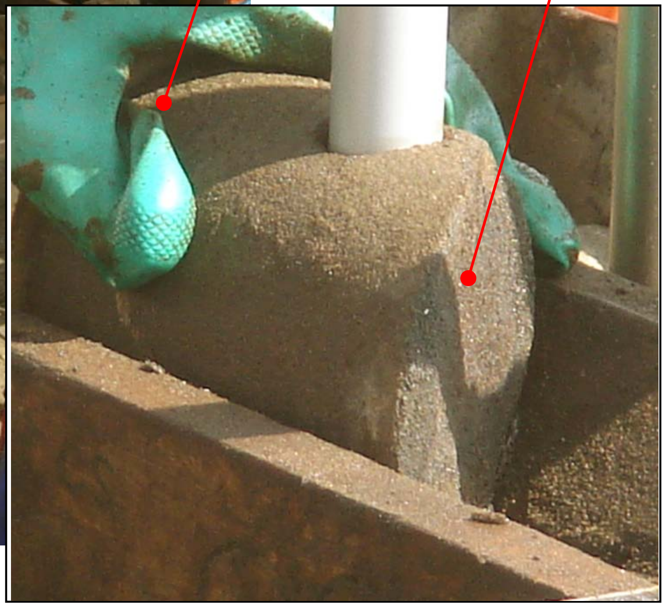
Cambay Analogies

- North Kadi oil field is a major oil producing field in North Cambay Basin, India. The field discovered in 1969 is producing from high permeability sandstone reservoir (500-3000mD) of Eocene age (same as Mangala). This reservoir is operative under active aquifer support. The field has an 80m gross hydrocarbon column (Mangala 300m). **The expected recovery factor is 34%** (same as Mangala).
- One of the Eocene age fields in Cambay Basin of India, having about 1000 MMbbls of initial oil in place, has got nine reservoirs of thickness varying from 14 ft to 66 ft. Two main multilayered reservoirs are being produced under peripheral water flood from early stage of exploitation. The estimated oil in place of these two reservoirs is 560 MMbbls and 170 MMbbls and **expected ultimate recovery is 55% and 61% respectively**.

Conclusion: In our opinion the comparisons between the Cambay and Barmer basins are valid as a means of backing up predictions of ultimate recovery factors of at least 30%+ - providing that waterflood techniques are successful.

Fatehgarh Reservoir Quality

Cutting plugs from a Baghyam Core



Source: Hulf Hamilton Photo

Excellent Reservoir Quality is the Key to the Rajasthan Development

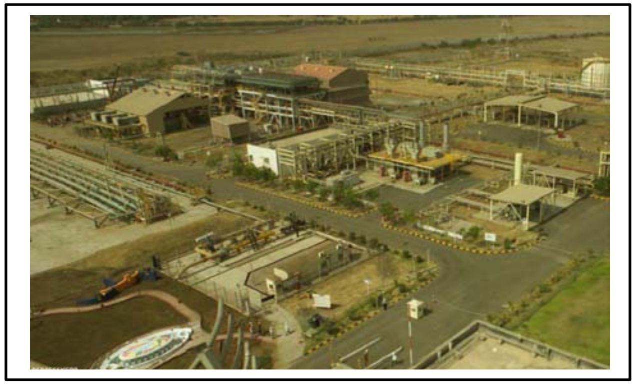
Core samples are cut across the reservoir to allow the physical properties of the rock to be determined such as permeability (flowability) and porosity (capacity to hold hydrocarbon).

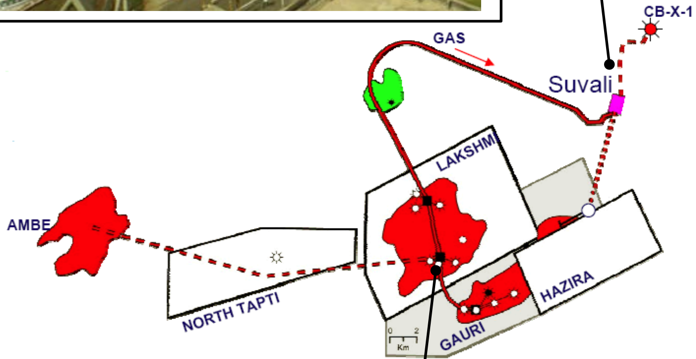
This close up picture shows a very 'sandy' plug being cut from the core and clearly shows the good quality very porous and permeable qualities. The actual permeability here is likely to be between 2000mD and 3000mD (very high)

- Certain factors related to the reservoir conditions in the Mangala field dictate the maximum flow rates attainable from the field combined with the total number of wells that can be produced.
- We calculate from Cairn and from reservoir pressure and temperature data from the Phoenix oil and gas* acreage the following data:
  - Average Mangala reservoir pressure 1400psi (low)
  - Average Mangala reservoir permeability (quality) 1000mD
  - Oil specific gravity 25API (low)
  - Average initial flow rates of 2000b/d (confirmed from well testing).
- Using this main data and other reservoir assumptions we can calculate that a single well could drain from a 40acre area.
- Cairn plans to drill 115 wells in phase 1 of development and 45 in phase 2.
- Initial drilling of 30 wells and water injectors would test the waterflood techniques and provide early cash flow.
- Assuming this to be the case we would anticipate an average 60,000b/d in the first year of production growing to a theoretical plateau of between 150,000b/d and 200,000b/d. We assume a 100,000b/d plateau in our valuation.

* Phoenix Oil & Gas hold adjacent acreage to North of Cairn Block on analogous geology.

Other Cairn Projects at Lakshmi Platform and Suvali





Source: Cairn Energy

Commentary

Objective

- Does Cairn have production and processing experience as a well known and successful explorer?
- Hulf Hamilton visited the Cambay basin production and processing facilities in November 2005 to reconfirm production and reserve levels and look into operating costs and upside and to address this question.
- We were particularly interested in the new oil production from Gauri – previously uneconomic thin oil sands now developed with relatively expensive horizontal wells (now that oil prices are high enough).

Observations

- The current development is shown left and consists of 3 platforms (2 on Lakshmi and 1 on Gauri) – current combined gross gas production is 120MMcfd on plateau.
- Cairn has a 49% working interest in this project (40% entitlement declining to 20% at end of project life in 2013).
- Cairn expects plateau production to continue for 2 years.
- Gross oil production is 3000b/d from a single well.
- Operating costs are relatively low ($1.6/boe).
- Total capital expenditure (plant, platforms & wells) has been gross $250MM.
- Gas is sold under contract to China Light and Power and BG @ $4.4/mcf.

Conclusions

- Lakshmi started production in 2002 and was followed by Guari in 2004.
- The fields are performing as expected with oil production as upside.
- Facilities are in excellent condition and appear to be well maintained.
- Gas prices are relatively good and the project benefits further from a 7 year tax holiday that expires in 2009.
- We have factored the above metric into our assessment and mainly because of higher adopted gas prices and lower opex.
- **Cairn has been working as the operator of oil and gas processing with a successful track record and we therefore see this as a good credential for taking on the Rajasthan developments.**

Productivity Assumptions

Cairn Drilling History in Rajasthan

Drilling Record

- Hulf Hamilton has maintained its own drilling record of Cairns activities in Rajasthan as part of the equity research it performs for certain clients.
- According to our own independent record Cairn had drilled 73 wells in Rajasthan in the period 1999 up to May 2005 (13 wells per annum average).
- Cairn claims to have drilled a further 52[4] wells in the last year up to 14th March 2006 and we think this is credible (52 wells per annum – previously Cairn has drilled 5 wells per month with 5 rigs, therefore over 10 months 52 wells is possible).
- We also believe that with the influence of ONGC, access to further production drilling rigs for the Mangala programme should not be difficult.
- The initial development of Mangala requires the drilling of 23 production wells and 12 water injectors from Oct 2006-Oct 2007 and this clearly looks achievable based on its historic drilling record.

Cairn Drilling Record.

PEL Phase	Well No.	Well name	Category	Spud Date	Drilled Depth (MD) (m)	Drilled Depth (TVDSS) (m)	Status	Year
Phase2 1	1	Guda-1	Exploration	31-Jan-99	2573	2505.2	Dry	1999
Phase2 2	2	Guda-2	Exploration	22-May-99	3707	3589.1	Discovery	1999
Phase3 1	3	Saraswati-1	Exploration	23-Sep-01	1836.5	1595.1	Discovery	2001
Phase3 Ext 1	4	Raageshwari-1	Exploration	30-Oct-02	3478	3415.1	Discovery	2002
Phase3 Ext 2	5	Raageshwari-1ST	Appraisal	14-Feb-03	1930	1732	Discovery	2003
Phase3 Ext 3	6	Saraswati-2	Appraisal	22-Mar-03	2288	2181.9	Discovery	2003
Phase3 Ext 4	7	Saraswati-3	Appraisal	16-May-03	1640	1515.9	Dry	2003
Phase3 Ext 5	8	RJ-D-1	Exploration	15-Jun-03	2540	2451.5	Dry	2003
Phase3 Ext 6	9	Kameshwari-1	Exploration	28-Jul-03	3544	3464.9	Discovery	2003
Phase3 Ext 7	10	GR-A-1	Exploration	17-Oct-03	2132	2055.4	Dry	2003
Phase3 Ext 8	11	GR-F-1	Exploration	25-Oct-03	2747	2691.3	Discovery	2003
Phase3 Ext 9	12	Raageshwari-2	Appraisal	15-Nov-03	1730	1672.8	Dry	2003
Phase3 Ext 10	13	GR-S-1	Exploration	02-Dec-03	2466	2405.6	Dry	2003
Phase3 Ext 11	14	Kameshwari-ST	Appraisal	12-Dec-03	1684.4	1608.3	Discovery	2003
Phase3 Ext 12	15	Mangala-1	Exploration	31-Dec-03	1336	1155.7	Discovery	2003
Phase3 Ext 13	16	Raageshwari-3	Appraisal	03-Jan-04	1723	1660.2	Discovery	2004
Phase3 Ext 14	17	N-J-1	Exploration	05-Jan-04	2632.9	2490.8	Dry	2004
Phase3 Ext 15	18	Aishwariya-1/Z (N-A-1/N-A-1Z)	Exploration	30-Jan-04	1634	1463.9	Discovery	2004
Phase3 Ext 16	19	Saraswati-4	Appraisal	20-Feb-04	1472	1382.3	Discovery	2004
Phase3 Ext 17	20	Mangala-1ST	Appraisal	05-Mar-04	1640	1337.1	Discovery	2004
Phase3 Ext 18	21	N-F-1	Exploration	20-Mar-04	2492	2338.3	Dry	2004
Phase3 Ext 19	22	Shakti-1 (N-C-1)	Exploration	05-Apr-04	1032	826.7	Discovery	2004
Phase3 Ext 20	23	Mangala-2	Appraisal	24-Apr-04	1830	1207.8	Discovery	2004
Phase3 Ext 21	24	Mangala-3	Appraisal	26-Apr-04	1935	1157.8	Discovery	2004
Phase3 Ext 22	25	Aishwariya-2/Z (N-A-2/N-A-2Z)	Appraisal	28-Apr-04	1484.4	1193	Discovery	2004
Phase3 Ext 23	26	Mangala-4	Appraisal	08-May-04	1336	1081	Discovery	2004
Phase3 Ext 24	27	GS-J-1/GS-J-1Z	Exploration	21-May-04	2028	1940	Dry	2004
Phase3 Ext 25	28	Aishwariya-3 (N-A-3)	Appraisal	22-May-04	1591	1309	Discovery	2004
Phase3 Ext 26	29	Mangala-3	Appraisal	07-Jun-04	1180	1002.6	Discovery	2004
Phase3 Ext 27	30	Mangala-6	Appraisal	15-Jun-04	1570	1086.1	Discovery	2004
Phase3 Ext 28	31	N-P-1/N-P-1Z	Exploration	17-Jun-04	1597	128	Dry	2004
Phase3 Ext 29	32	N-I-1/N-1-1Z	Exploration	23-Jun-04	650	462.2	Dry	2004
Phase3 Ext 30	33	N-D-1	Exploration	26-Jun-04	1891.9	1693	Dry	2004
Phase3 Ext 31	34	N-K-1/N-K-12	Exploration	05-Jul-04	1990	1617.2	Dry	2004
Phase3 Ext 32	35	Aishwariya-4 (N-A-4)	Appraisal	13-Jul-04	1657	1359.1	Discovery	2004
						3479.8	Discovery	2004
						1962.6	Dry	2004
Phase3 Ext 35	38	Bhagyan-1 (N-V-1/N-V-1Z)	Exploration	31-Jul-04	667	651.3	Discovery	2004
Phase3 Ext 36	39	Vijaya-1 (N-R-1)	Exploration	12-Aug-04	2565	2397.5	Discovery	2004
Phase3 Ext 37	40	Aishwariya-5 (N-A-5)	Appraisal	12-Aug-04	1435	1174	Discovery	2004
NC Ext 1	41	N-C-2	Appraisal	28-Aug-04	1002	792.9	Dry	2004
NC Ext 2	42	Shakti-2 (N-C-3/N-C-3Z)	Exploration	30-Aug-04	764	561.4	Discovery	2004
Phase3 Ext 38	43	N-T-1	Exploration	26-Sep-04	2075.5	1672.5	Dry	2004
NC Ex t3	44	N-C-4	Exploration	26-Sep-04	771	519.7	Dry	2004
NC Ext 4	45	N-C-5	Exploration	29-Sep-04	1300.6	1059.2	Dry	2004
Phase3 Ext 39	46	N-L-1	Exploration	02-Oct-04	1732	1212.5	Dry	2004
Phase3 Ext 40	47	N-F-2	Exploration	03-Oct-04	3120	2955.6	Discovery	2004
Phase3 Ext 41	48	N-W-5	Exploration	12-Oct-04	1514.3	1223.6	Dry	2004
NC Ext 5	49	N-C-6	Exploration	24-Oct-2004	1001	649.5	Dry	2004
NC Ext 6	50	N-C-7	Exploration	28-Oct-2004	667	643	Dry	2004
NC Ext 7	51	Shakti -3 (N-C-3/2)	Appraisal	2-Nov-2004	664	468.3	Discovery	2004
Phase3 Ext 42	52	N-X-1	Exploration	4-Nov-2004	1110	928.5	Dry	2004
NC Ext 8	53	Shakti-4 (N-C-3/3)	Appraisal	0-Nov-2004	744	496.9	Discovery	2004
Phase3 Ext-43	54	N-M-1	Exploration	16-Nov-2004	3000	2839.2	Dry	2004
Phase3 Ext-44	55	Raageshwari-5	Appraisal	5-Dec-2004	3739	3334	Discovery	2004
Phase3 Ext-45	56	W-A-1	Exploration	21-Nov-2004	2800	2757.1	Dry	2004
Phase3 Ext-46	57	Guda-3	Appraisal	23-Dec-2004	2320.5	2105.8	Discovery	2004
Phase3 Ext-47	58	W-B-1	Exploration	26-Dec-2004	2320	2261.6	Dry	2004
Phase3 Ext-48	59	GR-F-2	Appraisal	21-Jan-2005	2385	2299.6	Discovery	2005
Phase3 Ext-49	60	GR-A-2	Exploration	28-Jan-2005	3200	2854.7	Dry	2005
NC Ext 1	61	N-V-1ST	Appraisal	8-Feb-2005	1483	487.5	Discovery	2005
Phase3 Ext-50	62	Raageshwari-5	Appraisal	21-Feb-2005	3872	3739.9	Dry	2005
NC Ext 2	63	Bhagyan-2	Appraisal	24-Feb-2005	861	642.3	Discovery	2005
Phase3 Ext-51	64	Aishwariya-6	DOW	3-Mar-2005	909	520.7	Plugged	2005
Phase3 Ext-51	64	Aishwariya-6Z	DOW	29-Mar-2005	1809.3	1131.5	Discovery	2005
NC Ext 3	65	N-V-3	Appraisal	3-Mar-2005	767	461.9	Dry	2005
NC Ext 4	66	Bhagyan-3	Appraisal	11-Mar-2005	1330	715.4	Discovery	2005
NC Ext 5	67	Bhagyan-2ST1	Appraisal	24-Apr-2005	935	575.1	Discovery	2005
NC Ext 6	68	N-V-5	Appraisal	12-Apr-2005	1060	813.2	Dry	2005
NC Ext 7	69	Bhagyan-2ST2	Appraisal	17-Apr-2005	1129	463.64	Dry	2005
		Bhagyan- 2ST2Z	Appraisal	17-Apr-2006	978	500	Dry	2005
		Bhagyan-2ST2Y	Appraisal	17-Apr-2007	1156.7	489.25	Dry	2005
NC Ext 8	70	Bhagyan-4	Appraisal	21-Apr-2005	745	531.7	Discovery	2005
NC Ext 9	71	N-V-6	Appraisal	5-May-2005	1378	1158.7	Dry	2005
Phase3 Ext 50		Raageshwari-4Z	Appraisal	4-May-2005				
Phase3 Ext 52	72	N-I-2	Appraisal	11-May-205				2005
NC Ext 10	73	N-V-7 (-T)	Appraisal	15-May-2005				

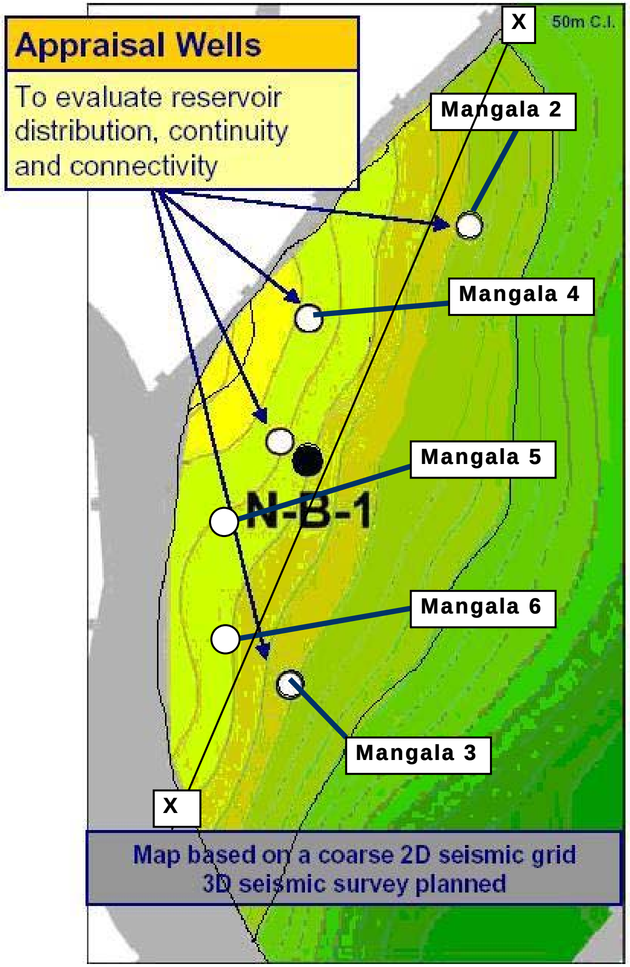
- Drilling success rate 47% 1999-2005

Conclusion: Cairn must achieve a certain drilling rate of wells per year to achieve the plateau oil production target of 100,000b/d by 2009 with 64 producers and 26 injectors (approximately 22 wells per annum). Based on its track record to date this looks achievable.

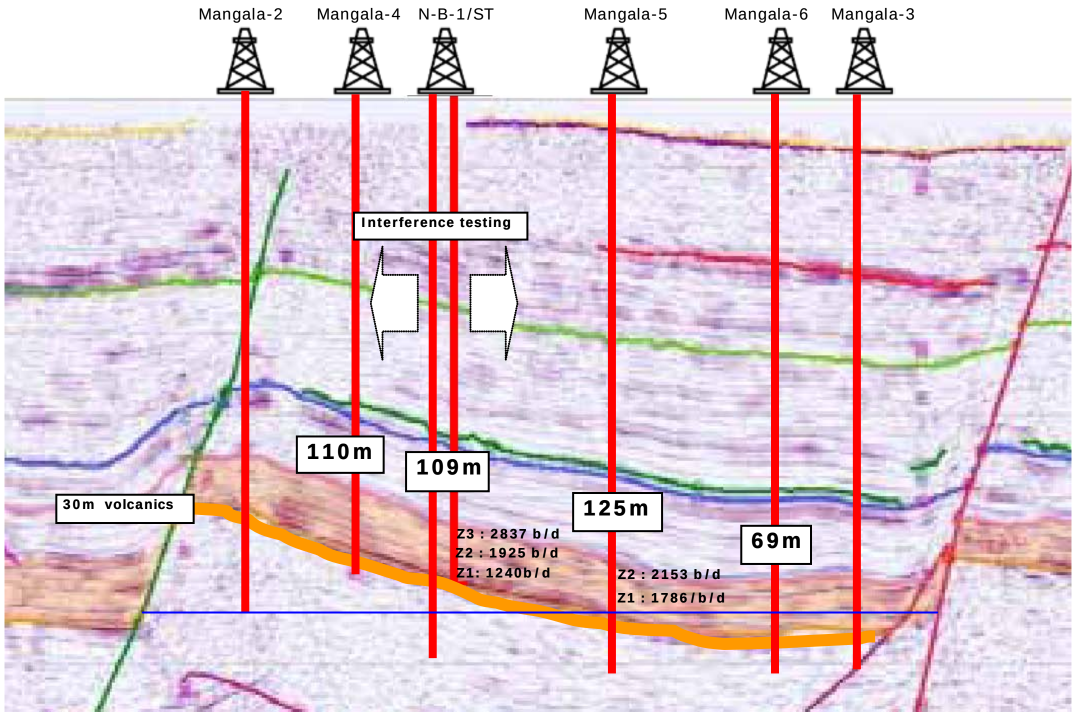
[4] Cairn has 5 exploration drilling rigs active in Rajasthan

Mangala Field Overview

Mangala Top surface



Mangala Section on X-X

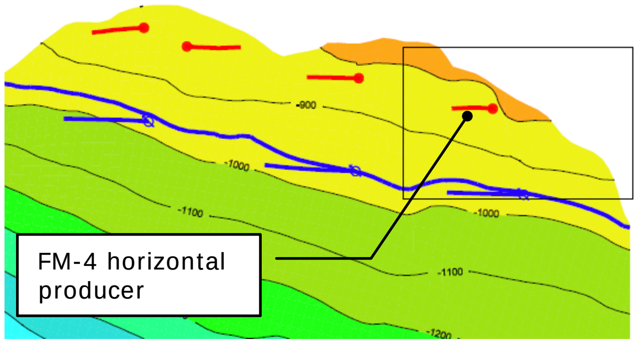


- Early wells drilled by Cairn onto Mangala largely established the field size and characteristics.
- Mangala-5/6 infill appraisal wells confirm reservoir extent in the southern part of the field.
- Interfernce testing between N-B-1 and Mangala 4/5 establishes reservoir connectivity.
- Encouraging result from 30m volcanic pay zone beneath main Fategarh formation.
- Mangala-5 flow rates correspond with testing in the central part of the field, confirming improving reservoir quality at lower depths. (test results shown on the wells)
- The Oil water contact (OWC) shown as blue horizontal line has been established from several wells and this has a major bearing on reserve certainty.
- We will model the predicted well performance in more detail on the following pages.

Conclusion: Mangala has been well drilled to establish primary reserve and later field performance data.

Horizontal Well Modelling

Horizontal wells in Mangala Field



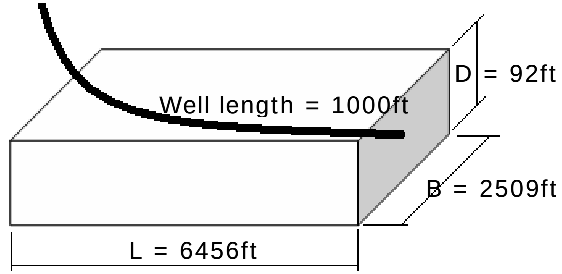
Source: Cairn Energy

Commentary

- We have carried out our own horizontal well rate analysis using established linear flow equations.
- We start by comparing the known data from a vertical well drilled in November 2004 – M5 well.
- This well flowed at a maximum stabilized rate of 1,900b/d at a 300psi drawdown
- We then take a reduced 150psi drawdown pressure and measured reservoir information and calculate the equivalent horizontal flow rate using several different methods.
- 'Drawdown' is a measure of how much the well is allowed to flow and this is reduced so as not to draw up water or produce too much sand.
- We calculate a maximum theoretical horizontal flow rate of 6,306b/d

Horizontal Well Model

- We assume the horizontal well drains from the following volume (approximately one quarter of the FM-4 formation).
- Horizontal wells are planned for the FM-3 and FM-4 formations with vertical wells in FM-1,2 and 5.



Horizontal Well Input Data

Reservoir Parameters		
Porosity	ø (frac)	0.2
Connate Water Saturation	Swc (frac)	0.1
Residual Oil Saturation	Sor (frac)	0.9
Oil Boundary Radius		2307
X direction Permeability	Kx (mD)	2109
Y direction Permeability	Ky (mD)	2109
Horizontal Permeability	Kh (mD)	2109
Vertical Permeability	Kz (mD)	703
Fluid Parameters		
Oil Density	þo (g/cc)	0.9
Water Density	þw (g/cc)	1.0
Oil Viscosity	µo (cP)	13.0
Oil F.V.F.	Bo	1.1
Endpoint Mobility Ratio	M	20.0
Well Parameters		
Wellbore Radius	Rw (ft)	0.3
Production Control		
Maximum drawdown	dP (psi)	150

Reservoir Size		
Block Length // to Well	2Xe	6456.0
Block Length perpendicular to well	2Ye	2591.0
Water Zone Thickness	Hw (ft)	182.0
Oil Zone thickness	Ho (ft)	92.0
Reservoir thickness	h (ft)	274.0
Oil in Place	OIP (stb)	47.1
Ratio Kv Kh		0.3
Drainage area from block size :	A (acres)	384.0
Equivalent drainage radius from block	Re (ft)	2307.5
Horizontal Well Length	(ft)	1000

Horizontal Well Output Data

METHOD	Rw' (ft)	S	PI	Flowrate
Borisov [1]	16.63	-4.20	56.72	8508
Giger	61.36	-5.50	76.53	11480
Giger,Reiss & Jourdan [1]	16.79	-4.21	56.83	8524
Joshi [1]	9.66	-3.65	51.20	7680
Van der Vlis et al [2]	17.87	-4.27	57.54	8630
Ozkan,Raghaven & Joshi [1 2]	1.52	-1.80	38.46	5769
Joshi [1 2]	6.98	-3.33	48.38	7257
Sparlin & Hagen [3]	0.00	634.40	0.44	67
Karcher et al [1 2]	5.75	-3.14	46.86	7028
Besson [1 2]	2.59	-2.34	41.44	6216
Renard & Dupuy [1 3]	0.00	395.53	0.71	106
Odeh & Babu			29.38	4407
Average (excluding G&W)				6,306b/d

Conclusion: Using established field data a horizontal well from the FM-4 could be 3 times as productive as a vertical well, FM-3 rates would likely be higher as the reservoir quality is better and vertical wells have flowed at up to 3,600b/d (10,000b/d horizontal potential assuming 3x multiple). It therefore appears that Cairn has been reasonably conservative when factoring in well performance to overall production profiles and particularly the 2P 368MMbbl profile shown overpage.

Mangala Development Drilling

Production History of Mangala Wells

	M-1 OHDST1 FM-2	M-1 OHDST2 FM-1	M-1 OHDST3 FM-1	M-1 Prod FM-1	M-1 Prod FM-1	M-1-ST OHDST1 FM-3	M-1-ST OHDST2 FM-1	M-5 OHDST1 FM-5	M-5 OHDST2 FM-4	M-5 OHDST3 FM-1	M-5 CHDST1 FM-5	M-5 CHDST2 FM-4	M-5 CHDST3 FM-3
Date	1/24/04	1/25/04	1/28/04	3/21/04	5/22/04	3/26/04	3/27/04	7/3/04	7/5/04	7/7/04	11/20/04	11/26/04	11/30/04
Interval Top (m)	948	873	825	~873	~873	913	763	906	881	731	908	383	861
Interval Base (m)	964	889	838	~889	~889	935	777	918	906	751	935	396	873
NetPay (m)	11.4	10.7	10.5	10.7	10.7	21.1	3.1	11.5	21.3	13.7	26.8	13	38.7
Duration (hrs)	5.5	7	7	13	162	5.4	7.1	5	7	9	18	7	24
Max Drawdown (psi)	400	400	400	--	--	600	500	300	300	330	300	300	300
Avg Flow Rate (bopd)	1240	1925	2837	2640	2000	2800	1250	88	1786	2153	1230	1900	3620
Choke x/64"	68	64	96	96	56	128	56	24	80	72	32	48	64
FTHP (psi)	122	190	151	180	220	198	124	20	134	144	280	188	271
Oil Quality (°API)	23.7	28.8	29.4	30	30	28.0	30.0	28.4	28.7	29.8	29.7	29.5	29.2
Oil Viscosity (cp)	50	9.6	13	9.6	9.6	13	11	13	13	13	13	13	13
Initial Pressure (psi)	1615	1526	1475	1530	1532	1574	1400	1565	1533	1374	1570	1539	1479
Permeability(md)	4170	2490	8150	2480	2490	14683	3360	218	642	3556	291	545	25995
Skin	-0.7	0.5	1.3	-0.6	1.5	2.7	0.4	5.2	-0.9	0.6	-3	-2.5**	0.2
Avg. PI (b/d/psi)	4.1	7.3	15	8.3	6.4	48	2.6	0.4	5.1	8.3	3	2	30
												Some Sand Production	

Proposed P50 Profile (368MMbbl)

Date	Oil Production (000 b/d)	Fluid	Producers Wells (No)	Injectors Wells (No)	Total Wells (No)	Rate per Oil well (000 b/d)	Water Cut (%)
Dec-07	70	73	23	12	35	3.04	4%
Dec-08	94	113	46	19	65	2.04	17%
Dec-09	100	165	64	26	90	1.56	39%
Dec-10	100	214	75	40	115	1.33	53%
Dec-11	100	281	88	45	133	1.14	64%
Dec-12	94.5	398	91	57	148	1.04	76%
Dec-13	66.6	400	89	57	146	0.75	83%
Dec-14	51	400	89	57	146	0.57	87%
Dec-15	41.8	400	87	57	144	0.48	90%
Dec-16	35.6	400	84	57	141	0.42	91%
Dec-17	31.9	400	79	57	136	0.40	92%
Dec-18	28.8	400	77	57	134	0.37	93%
Dec-19	25.9	400	76	57	133	0.34	94%
Dec-20	23.3	400	75	57	132	0.31	94%
Dec-21	21.2	400	75	57	132	0.28	95%
Dec-22	19.6	400	74	57	131	0.26	95%
Dec-23	18.7	400	72	57	129	0.26	95%
Dec-24	17.6	389	68	57	125	0.26	95%
Dec-25	16.1	380	67	57	124	0.24	96%
Dec-26	14.6	361	63	57	120	0.23	96%
Dec-27	13.6	353	62	57	119	0.22	96%
Dec-28	12.6	337	58	57	115	0.22	96%
Dec-29	11.7	319	55	57	112	0.21	96%
Dec-30	11.1	312	55	57	112	0.20	96%
Dec-31	10.4	302	51	57	108	0.20	97%
Dec-32	9.9	296	51	57	108	0.19	97%
Dec-33	9.6	292	49	57	106	0.20	97%
Dec-34	8.9	273	45	57	102	0.20	97%
Dec-35	8.4	260	44	57	101	0.19	97%
Dec-36	7.6	231	37	57	94	0.21	97%
Dec-37	7.1	218	37	57	94	0.19	97%
Dec-38	6.6	201	32	57	89	0.21	97%
Dec-39	6.1	185	32	57	89	0.19	97%
Dec-40	5.7	175	30	57	87	0.19	97%
	368 MMbbl						

Phase 1 assumes 23 producers and 12 injectors drilled from Oct 06 – Oct 07 and this appear reasonable and achievable.

The next phase to peak production (100kbd) assumes additional 55 wells over next 2 years, e.g. 26 wells per year – also reasonable.

This data implies a 334 day per year profile (e.g. 1 month down time). This is a reasonably conservative assumption on Cairn's part

Commentary

Historic results

- We have shown the test results from the wells drilled on Mangala to date, as published by Cairn.
- These results relate to production testing of exploration and appraisal wells.
- The rates shown relate to individual formations.
- Production wells would be better optimized for efficient production from each formation.
- Horizontal wells would be utilized also.

Future Predictions

- The production profile for the 368MMbbl 2P reserves case is shown left **(first oil 4 years from discovery - 2004)**
- This prediction is based on the output from a sophisticated computer simulation utilizing
  - Core data taken from wells
  - Oil sample data taken from wells
  - Electric readings of reservoir data from wells
  - Pressure readings from wells
  - seismic data showing reservoir size & extent.
- The main uncertainty in the modeling relates to the last point – reservoir size.
- Cairn appears to have done everything feasible to make a fair prediction of production rates.
- Our simple calculations appear to back-up the claimed rates from the Mangala production wells.
- It therefore appears reasonable to us that a 100kbd plateau could be reached by 2009.

Water Handling

- Note from the 'Fluid' column how production increases rapidly from 2012.
- Fluid is defined as oil + water.
- Water is produced rapidly after the water injected to maintain reservoir pressure 'breaks through'.
- The prediction of this phenomenon is a standard reservoir engineering problem.
- Computer simulation and laboratory work carried out by Cairn is standard practice and the results presented by Cairn appear reasonable.

Conclusion: The oil and water production profiles presented by Cairn rely on industry standard methodologies that appear reasonable.

Capex Assumptions

Mangala Capex

Mangala Development Capital Expenditures

No		Base Facility ($MM)	Base Facility (%)	Expanded Facility ($MM)	Estimate ($MM)
1	WELLPADS 18 Wellpads (12 at start-up, 6 by 2010)	92	7%	18	132
2	GROUP GATHERING STATION (GGS)	98	8%	14	133
3	CENTRAL PROCESSING FACILITY (CPF)	101	8%	9	132
4	CENTRAL TANK FARM (CTF)	27	2%		32
5	METERING	1	0.1%		1
6	PIPELINES	82	7%	10	111
7	CENTRAL POWER PLANT	36	3%	16	63
8	INFRASTRUCTURE / GENERAL	10	1%		12
	i) Power Distribution CPP to Wellpads				
	ii) Fibre Optics - Mangala				
	iii) Roads – Mangala and Water Wells	7			
	iv) Spares – Mangala & Raageshwari Facilites	3			
9	ENGINEERING (Inclusive Mangala, Raageshwari Gas and Water Well Facilities and Pipelines)	60	5%		72
10	CONSTRUCTION MANAGEMENT (Inclusive Mangala, Raageshwari Gas and Water Well Facilities and Pipelines)	16	1%	1	21
11	RAAGESHWARI FACILITIES & PIPELINES	47	4%	4	60
12	WATER WELL FACILITIES	8	1%		10
13	PROJECT MANAGEMENT & ASSET RELATED COSTS	164	13%	7	205
	i) Seismic Surveys	27			
	ii) Land Acquisition	5			
	iii) CAR Insurance	4			
	iv) Development Studies	27			
	v) Project M'gmt Team	37		4	
	vi) Pre-Operations	19			
	ix) Base Office Costs	14			
	x) G&A	32		3	
14	**DEVELOPMENT WELLS**	**443**	**36%**		**532**
	i) Mangala Development Wells and MGA	241			
	ii) Raageshwari Gas Wells and MGA	192			
	iii) Source Water Wells and MGA	11			
15	COMMISSIONING	29	2%	2	37
16	SUBTOTAL SURFACE FACILITIES / WELLS	1214		81	1553
17	PARENT COMPANY OVERHEAD (1%)	11	1%	3	16
18	UNALLOCATED PROVISIONS	22	2%		
19	TOTAL (16 to 18)	1247	$3.69/bbl	83	1569
20	GRAND TOTAL MANGALA - BASE + EXPANDED	1330	$3.61/bbl		1569
21	Total including additional ($85MM) for 'To Mature' Mangala wells	1415	$3.84/bbl		

Source: Cairn energy

Conclusion: Development drilling represents the largest most uncertain item in regard to Mangala Capex.

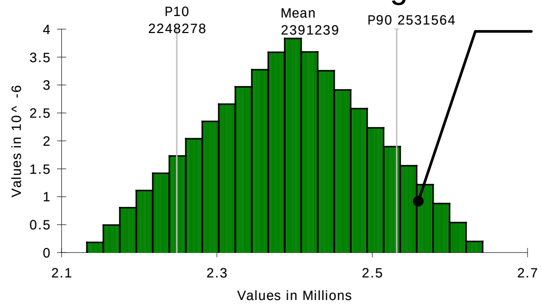
Commentary

- By far the largest element of total capex is Development wells, as shown highlighted in red on the left.
- The Base facility reflects costs through the life of the debt facility.
- Expanded facility shows additional late life drilling and plant modifications.
- As far as uncertainty is concerned we see this concentrated in Development drilling.
- In our opinion the erection of:
  - Gathering Stations
  - Central Processing
  - Tank Farm
  - Metering
  - Pipelines
  - Water facilities
  - other infrastructure

  Is largely 'off the shelf' standard engineered items or areas of higher predictability.
- Development drilling needs further investigation on a probabilistic basis.
- We need to look at the time and cost elements used to calculate drilling costs

Variation in Drilling Costs

Horizontal Well Cost Range

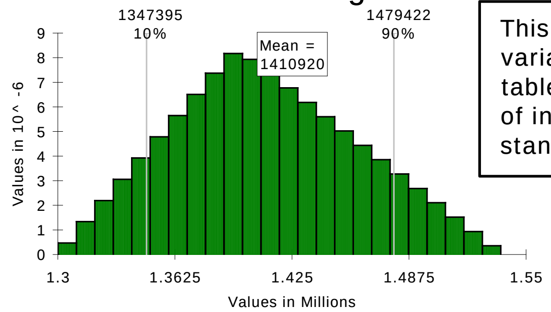


This distribution shows the range of possible horizontal well costs for certain variations in input cost, namely
- Time to drill well
- Material costs
We have assumed a triangular range for well time and a Gaussian range for well material cost (steel, completions, wellheads etc)

Horizontal Well Data		Average Depth (m)	Average Days (Day)	Cost per day ($)	Total well cost ($MM)
Drilling	Horizontal Well	2170	20.87	59574	1243111
Material					1148128
					$ 2,391,239

Well Input Variable	Distribution Type	Lo	Mid	High
Horizontal well time range	Triangular	17 days	21 days	25 days
Horizontal well materials	Gaussian	$ 2,132,499	$ 2,391,239	$ 2,642,200

Vertical Well Cost Range



This red cells show the variables and the lower table shows the range of inputs (±20% and standard deviation of 1)

Vertical Well Data		Average Depth (m)	Average Days (Day)	Cost per day ($)	Total well cost ($MM)
Drilling	30-45 Degree Vertical well	1756	13.47	41742	562126
Material					848794
					$ 1,410,920

Well Input Variable	Distribution Type	Lo	Mid	High
Vertical well time range	Triangular	11 days	13 days	17 days
Vertical well Materials	Gaussian	$ 1,347,000	$ 1,410,920	$ 1,479,422

Variables for Horizontal wells

- We have looked at the main variables in drilling and assumed:
  - time to drill on fixed rig rate
  - cost of materials
  as the main unknowns.
- Using Monte Carlo simulation we can run the algo rhythm for the cost of each well (time x rig rate + material cost), based on mid range data provided by Cairn.
- Once we establish the possible range for each of these variables the Monte Carlo simulation calculates the chance of possible outcomes.
- For results are shown on the graphs as follows.
- **Vertical well range**
  - lo $1.35MM
  - Med $1.41MM
  - Hi $1.48MM
- **Horizontal wells**
  - lo $2.24MM
  - Med $2.39MM
  - Hi $2.53MM
- We know how Cairn has calculated the Mid case development capex of $443MM shown on the previous page so we can re run that calculation using the range of data above to look at the variation in overall Capex.

Conclusion: Horizontal and Vertical well cost range can be established by varying time and materials cost within a fixed range.

Variation in Drilling Costs

Calculation of total Development Drilling

	Well Quantity (no)	Lo	Mean	Hi	Lo total	Mean total	Hi total
				Well cost ($MM)			
Total Horiz producers	16	2.25	2.39	2.53	36.0	38.3	40.5
Total vertical producers	138	1.35	1.41	1.48	185.9	194.7	204.2
Total Injectors	60	0.12	0.13	0.13	7.4	7.7	8.1
Water wells	24	0.45	0.45	0.45	10.8	10.8	10.8
Raageshwari Additions	33	1.35	1.41	1.48	44.5	46.6	48.8
Raageshwari Gas wells					116.0	144.9	173.9
					400.4	443.0	486.3

- The red box shows our assumptions in calculating the Mid case Development drilling shown in the Cairn summary capex table on page 25.
- If we input the range of drilling costs calculated on the previous page we can also establish 'lo' and 'hi' cases as shown either side of this red box.

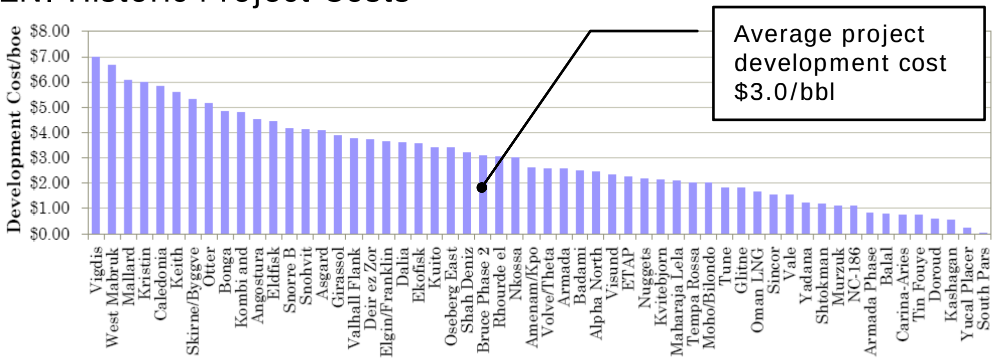
Commentary

- The analysis demonstrates that the Development drilling range could vary by ±10% for input variables established in a realistic range.
- In our opinion development drilling presents the greatest technical uncertainty and the results of our statistical analysis show that the range of uncertainty is relatively small.
- We think the reason for this is that the materials used for completing wells are likely to vary less than the time taken to drill a well.
- So even though we vary completion time by ±20%, the outputs only vary by half of this amount.

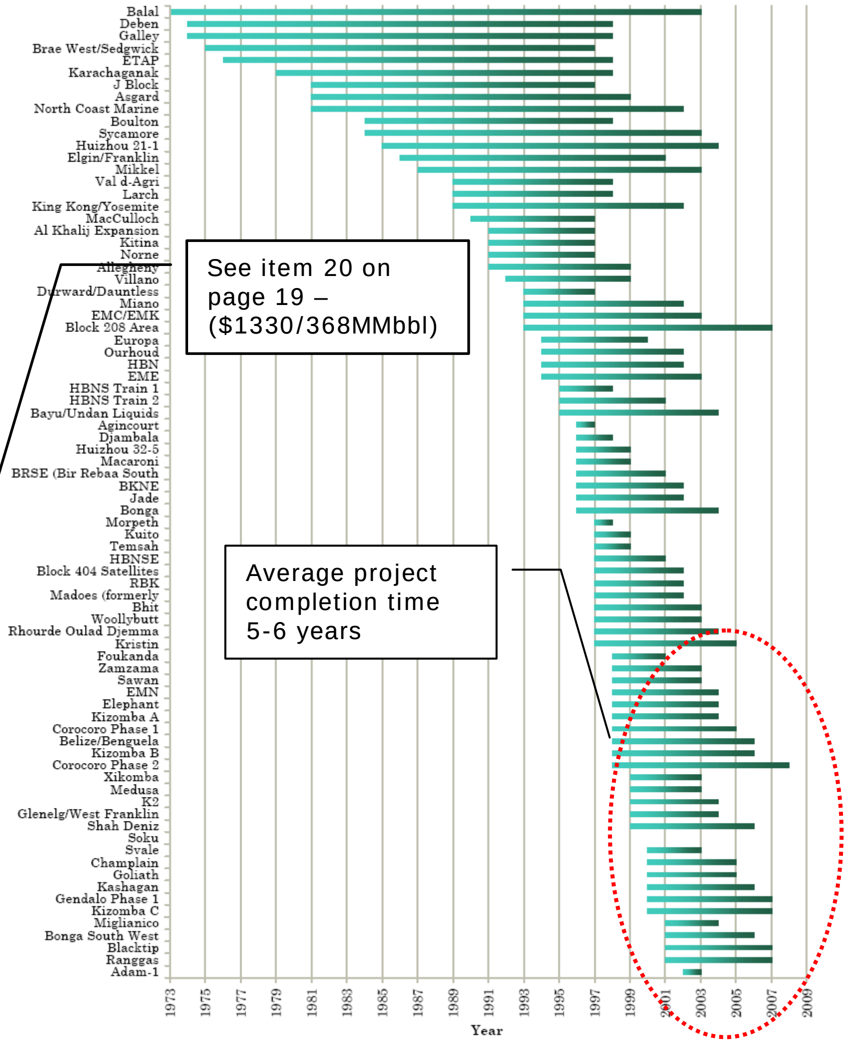
Conclusion: Our high case drilling estimate is $486MM vs. the $443MM estimated by Cairn in its most likely scenario for the 'Base Case' capex.

Oil Project Case Study - ENI

ENI Historic Project Costs



ENI Project Timescale (1973-2009)



Source: JS Herold

Specific Historic Project Costs

Operator	Country	Project	Gross Reserves (MMbbl)	Peak Production (000 b/d)	No Wells	Project Lead Time (years)	3rd party Capex ($/bbl)	Cairn Capex
ENI	Algeria	ROD	300	78	17	4	1.78	
ENI	Italy	Val d-Agri	468	100	42	6	3.00	
Total	Algeria	Rhourd el Baguel	450	100	40	6	2.89	
Murphy Oil	Malaysia	Kikeh	440	120	12	4	3.50	
Murphy Oil	Ecuador	Block 16	305	75		6		
Anadarko	Algeria	Ourhoud	250	230	80	7	1.5	
Average Data				**117**	**38**	**6**	**2.53**	**3.61**

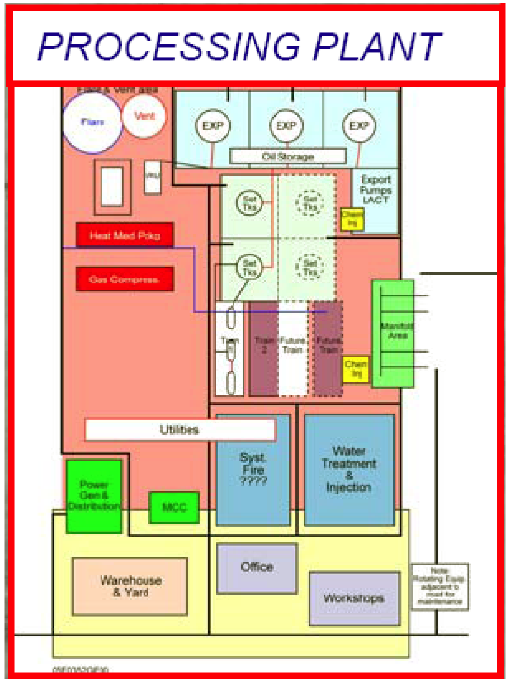
Commentary

- What Cairn is attempting to do in Rajasthan is what all large integrated oil companies do on a larger scale.
- Larger integrated oil companies are measured by
  - ability to find hydrocarbons frequently
  - ability to cost effectively develop hydrocarbons
- We have taken one company – ENI, the major Italian integrated oil company with oil and gas projects in similar (desert) locations to Rajasthan.
- The average Project development cost is $3.0/bbl and average project completion time (for recent projects started 2000+) is around 5 years.
- If we pick out projects from around the world that are more identical (reserves & production) to Mangala we can be more specific about a $2.66/bbl capex and again, 5 year lead time (from discovery to first oil)

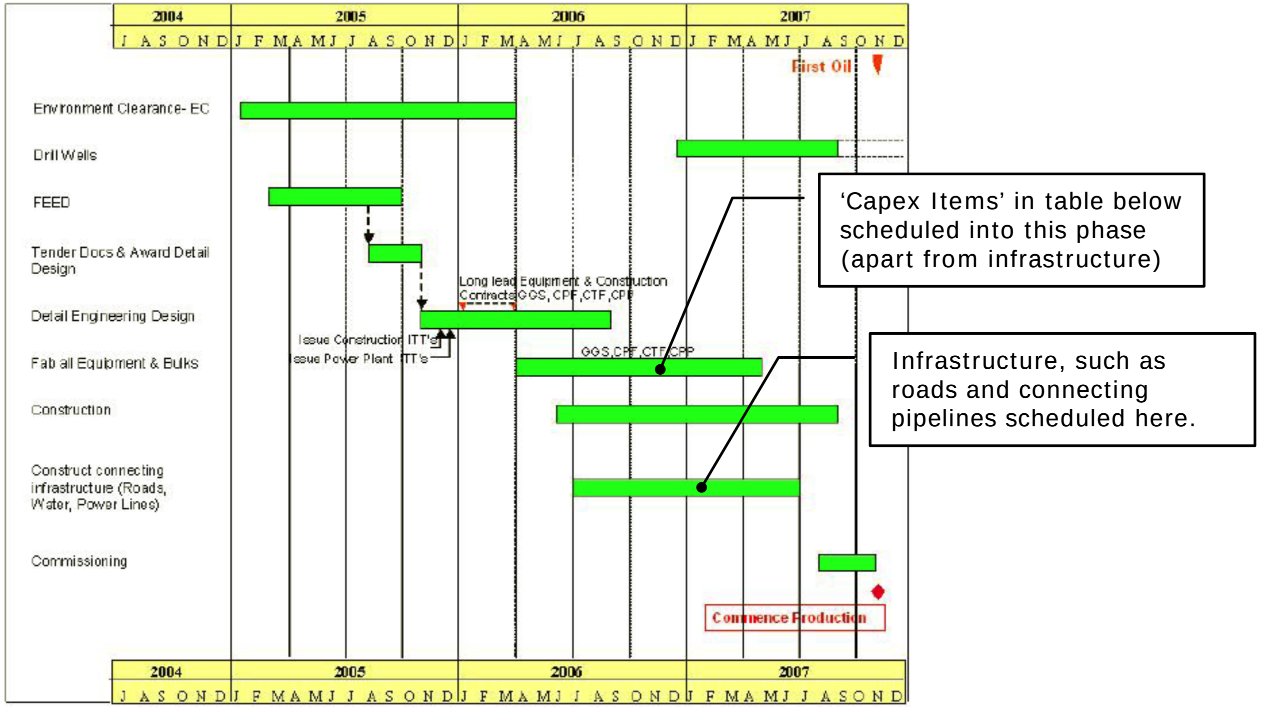
Conclusion: Historic data from other operators established $2.53/bbl and 5 years as benchmark project cost/time factors compares to Cairn $3.61/bbl and just under 4 years for Cairn (Cairn is higher mainly because of the additional water injection expenditures required). In our opinion this is technically feasible, assuming no political/commercial delays.

Non Drilling Capex Items

Schematic of Mangala Processing Plant



Project Schedule



Commentary

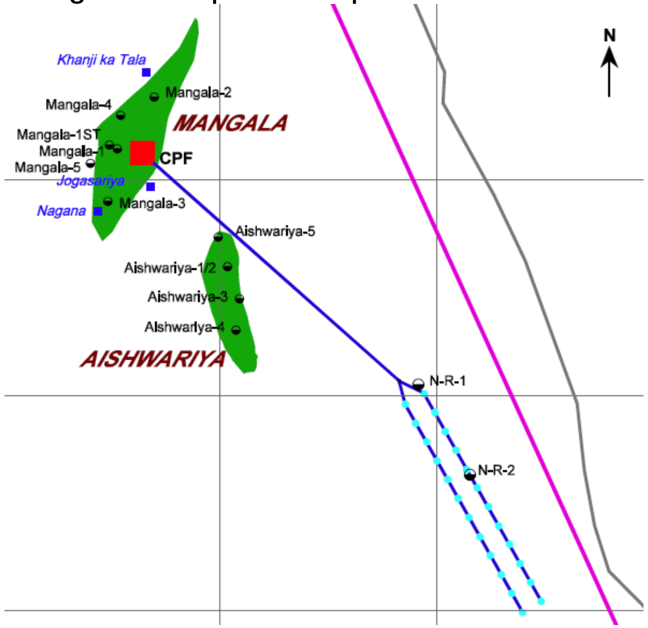
- We have established that the dominant capex item in the Mangala project is development drilling $443MM (36%) of total $1247MM.
- In our opinion the development drilling presents the most uncertain area of capex as far as potential time delays are concerned.
- The remaining key items are:

Capex Item	**Description**	**Scope for Delay**
Well pads	18 well pads planned for 219 wells	Modular design, low project delay risk
Gathering Stations	Takes production from pads with slug/sand catchers	Standard design, low project delay risk
Central Tank Farm	5 day (500,000bbls) storage capacity – fabricated on site.	Standard design, steel requirement, medium project delay risk
Central Processing Facility	Process water and gas	Standard design, low project delay risk.
Central Power Plant	4 x 13MW gas turbines	Standard design, low project delay risk.
Infrastructure	Connecting well pads – Gathering station - Plant	Standard design, steel requirement, medium project delay risk

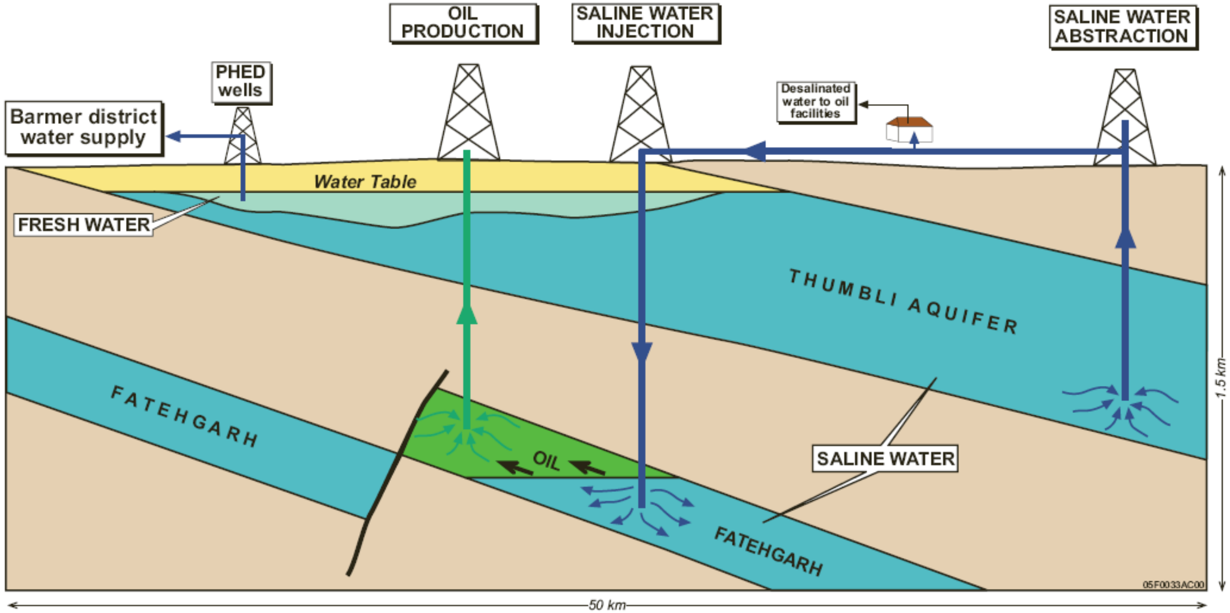
Conclusion: Most of the non development well items are industry standard design so providing that contractors have been booked/appointed, the scope for delay is relatively small as technical uncertainties are minimized through modularity.

Water Injection Plans

Mangala – Aquifer Map



Aquifer Extraction – Injection Scheme



Commentary

Water Extraction

- Cairn plans to extract water from the Thumbli aquifer through 24 water extraction wells ($10.8MM).
- Cairn has calculated how much water will be required over the life of the field from its own computer simulation of the reservoir (440MMbbls water) and this seems a reasonable value to us given the planned extraction of 368MMbbls of oil and allowing for some water loss into the reservoir.
- A total extraction of 560MMbbls is planned and other uses will be for production process operations and drinking etc.
- The water will also be heated in a water treatment facility ($8.35MM) and this seems a reasonable assumption to us.
- Cairn has carried out a number of detailed studies by Water Management Consultants (WMC) and supported by the national Indian company Hydro Geosurvey Consultants and this seems an appropriate course of action in our opinion.

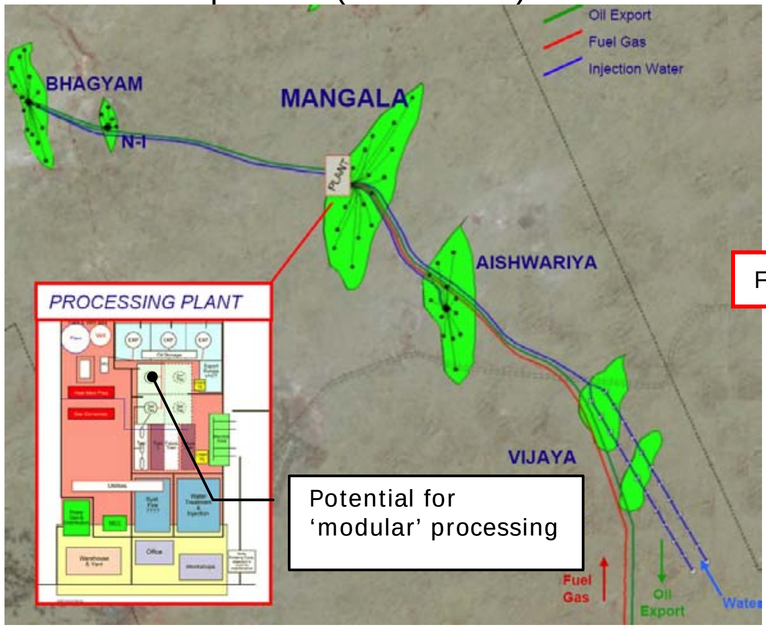
Water Injection

- The water is then pumped 20km-30km north to be re-injected into the Fatehgarh reservoir to support production on Mangala and the other fields.
- It was decided to heat the water after an injectivity trial conducted in 2005 concluded that hot water helped to reduce the waxy characteristics of the crude and improved productivity.
- The energy for water heating comes from the 50MW, gas powered Central Power Plant ($36.39MM), appropriately sized to cover all facility power requirements.
- The gas comes from the Raagashwari gas wells ($145MM), factored into the development.

Conclusion: Cairn has carried out appropriate tests/studies to predict the optimum cost/performance of its water injectivity programme.

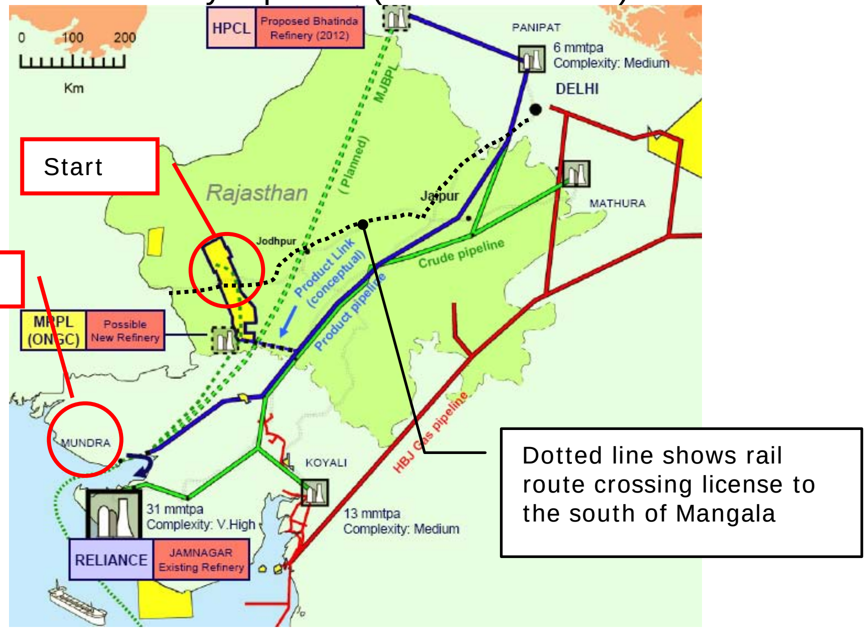
Pipeline Issues

Inter Field Pipelines (Cairn Cost)



Source: Cairn Energy

Inter Country Pipeline (Gov India cost)



Source: Cairn Energy

Commentary

- Cairn must make certain contingency requirements (see left) to allow for the fact that full export by 2008-2009 may not be possible.
- The contingency plan is to consider rail export at 35,000b/d.
- Assuming arrangements with Indian rail can be made (and we see little potential for delay here).
- We would assume that the Central Processing Facility and Power Plant will be installed to handle the 200,000bfpd as originally planned.
- Scope for scaling back would be on drilling pads and numbers of wells.
- The 23 wells and 12 injectors would be all that would be initially required, with water injection scaled back appropriately.

Commentary

- Although Cairn is not paying for the main export pipeline (Mangala – Mundra), the delay in construction could have implications for the delayed sale of crude production from Rajasthan.
- JP Kenney has been employed by Cairn to analyse the pipeline project with the following conclusions:
  - Twin 18” heated (60º-90º) pipelines with 150,000b/d capacity
  - Would cost $456MM.
- The key risk with the project is that if it is not started soon, certain critical path items could delay the project and these are
  - Ordering pipe (8 months)
  - Ordering heaters (6-7 months)
  - Regulatory requirements of routing (12-16 months)
- This is why Cairn must consider contingency plans at Mangala.

Conclusion: In our opinion export delays would be accommodated by scaling back drilling and injection wells (and pads). Process plant and other surface facilities would likely go ahead as planned for later utilization.

Opex Assumptions

Mangala Opex

Cairn Operating Costs

Mangala Description	Q3-Q4 2007	2008	2009	2010
Manpower	5,768	23,073	23,073	23,073
Field Security	911	1,822	1,822	1,822
Well & Reservoir Management	408	2,211	4,180	6,822
Transport & Logistics	1,157	2,313	2,313	2,313
Consumables	12,636	32,360	29,438	27,673
Maintenance	6,978	13,956	13,956	13,956
HSE	588	1,176	1,176	1,176
Work over		13,700	13,700	13,700
Insurance	1,000	2,000	2,000	2,000
G&A	1,500	3,000	3,000	3,000
PCO @ 1%	309	956	947	955
Total Operating Cost - Mangala	31,255	96,567	95,605	96,490

Raageshwari DG Description	Q3-Q4 2007	2008	2009	2010
Manpower	419	837	837	837
Field Security	26	51	51	51
Well & Reservoir Management	35	280	280	280
Transport & Logistics	142	284	284	284
Operating Supplies & Consumables	345	694	715	739
Maintenance	231	926	926	926
HSE	85	171	171	171
Work over	13	100	400	400
Insurance	50	100	100	100
G&A	50	100	100	100
PCO @ 1%	14	35	39	39
Operating Cost - Raageshwari DG	1,410	3,578	3,903	3,927
Total Operating costs ($MM)	32,665	100,145	99,508	100,417
	$3.58/bbl	**$2.74/bbl**	**$2.73/bbl**	**$2.75/bbl**
Production (MMbbl)	9.12	36.55	36.45	36.52

3rd Party Operating Costs

- We compare the Mangala project to several other international projects of a similar nature, e.g.:
  - onshore desert conditions.
  - similar reserves and production.
- The results show that Cairn opex stabilizes at $2.75/bbl compared to the Global average of $4.32/bbl.
- We note that 'Manpower' represents the second largest portion of operating costs and would speculate that Indian Manpower costs are some of the lowest in the world.
- This is how we would explain the lower unit costs.
- This is backed up by Cairn having established an opex track record in India of less than $1.6/bbl in its Cambay Basin facilities.

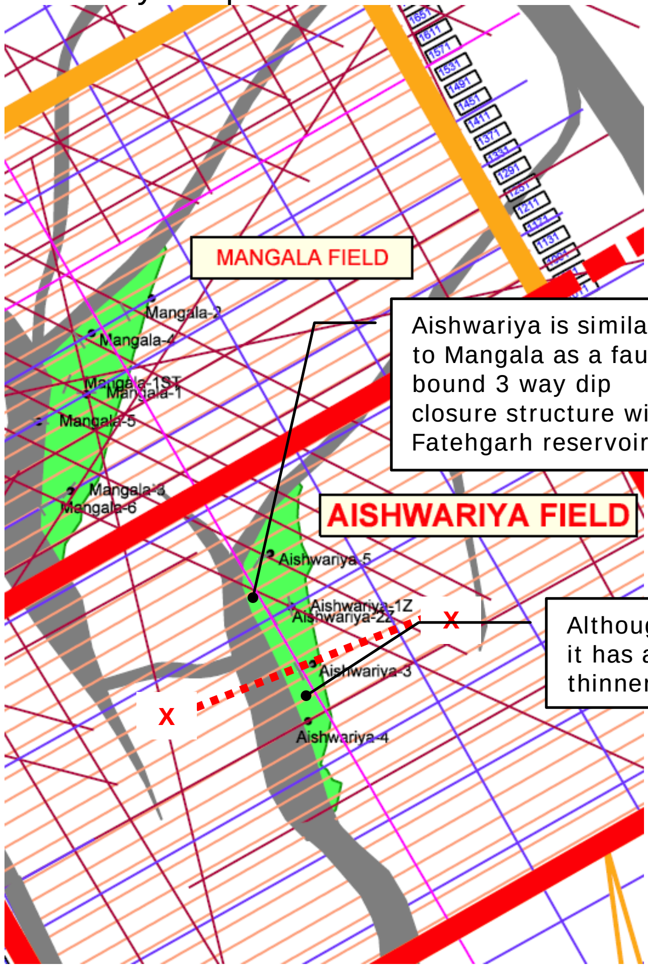
Operator	Country	Project	Gross Reserves (MMbbl)	Peak Production (000 b/d)	No Wells	Project Lead Time (years)	Opex ($/bbl)
ENI	Algeria	ROD	300	78	17	4	4.23
ENI	Italy	Val d-Agri	468	100	42	6	3.40
Total	Algeria	Rhourd el Baguel	450	100	40	6	2.56
Murphy Oil	Malaysia	Kikeh	440	120	12	4	6.25
Murphy Oil	Ecuador	Block 16	305	75		6	5.18
Anadarko	Algeria	Ourhoud	250	230	80	7	
Average Data				**117**	**38**	**6**	**4.32**

Conclusion: Cairn unit opex of $2.75/bbl is 36% lower than 3rd party calculated opex costs and we think this is largely due to lower manpower costs.

Appendices

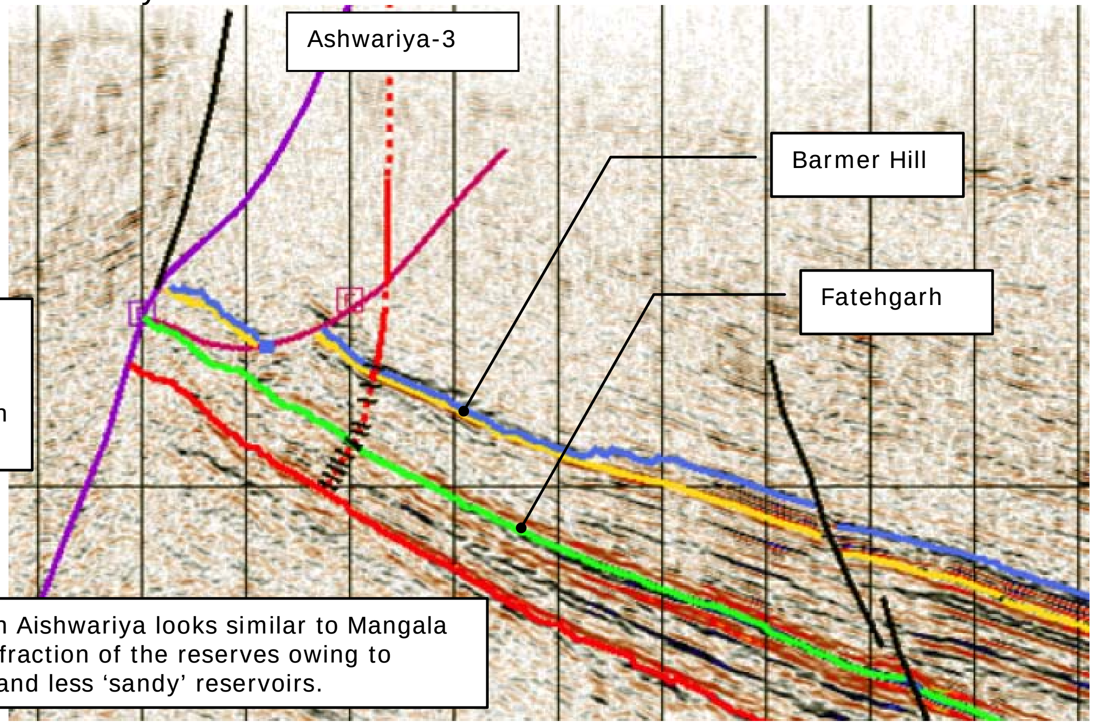
Aishwariya Field Overview

Aishwariya Top surface



Source: Cairn Energy

Aishwariya Section on X-X



- Ashwariya was discovered on the 11th May 2004, 4 months after Mangala.
- The diagram left shows the identical nature of the tilted fault block structures imaged from seismic.
- The diagram on page 7 shows the paleo site of the Ashwariya, south of Mangala and this partly explains the smaller reserve size of the field.
- Aishwariya looks similar to Mangala from a plan view but because the sand bodies that make up the reservoir are generally thinner and less 'pure' of sand content, so the actual oil reserves are about 13% of the size of Mangala, e.g. P50 Gross of 48MMbbls.
- Where reservoir is present it is of the same quality as Mangala and the oil that fills the reservoir is the same waxy, medium gravity 27API-31API crude.
- In our opinion Cairn has adequately drilled, cored, sampled and modelled Ashwariya to predict the location and character reseervoir targets to develop the field with 51 wells.

Conclusion: Aishwariya has been well drilled to establish primary reserve and later field performance data.

Aishwariya Capex

Aishwariya Development Capital Expenditures

Item No	Description	Base Facility ($MM)	(%)
1	WELLPADS 9 Wellpads.	19.97	9%
2	GROUP GATHERING STATION (GGS)	21.01	9%
3	CENTRAL PROCESSING FACILITY (CPF)	11.85	5%
4	ELECTRICAL EQUIPMENT WELLPADS 9 Wellpads.	1.65	1%
5	ELECTRICAL EQUIPMENT GGS / CPF	3.93	2%
6	BUILDINGS	2.66	1%
7	OSBL	4.09	2%
8	PIPELINES	12.47	5%
9	INFRASTRUCTURE / GENERAL	3.03	1%
10	ENGINEERING & PROCUREMENT (For Aishwariya Surface Facilities)	8.78	4%
11	CONSTRUCTION MANAGEMENT (For Aishwariya Surface Facilities)	2.2	1%
12	PROJECT MANAGEMENT & ASSET RELATED COSTS	32.21	14%
13	**DEVELOPMENT WELLS**	**85.1**	**37%**
14	SUBTOTAL SURFACE FACILITIES / WELLS	209.0	92%
15	PARENT COMPANY OVERHEAD (1%)	2.09	1%
16	CONTINGENCY (10% ON FACILITIES / WELLS)	16.53	7%
19	TOTAL (14 to 16)	227.6	100%
20	GRAND TOTAL AISHWARIYA DEVELOPMENT	227.57	$4.74/bbl

Similar % to Mangala as we would expect for the development of a similar reservoir, albeit smaller.

Unit capex (based on 48MMbbl Gross 2P recoverable) is higher than $3.61/bbl for Mangala as the reserves are relatively small for the minimum number of wells and facilities required for a base development – so this metric is reasonable.

Source: Cairn energy

Commentary

- By far the largest element of total capex is Development wells, as shown highlighted in red on the left.
- The Base facility reflects costs through the life of the debt facility.
- As far as uncertainty is concerned we see this concentrated in Development drilling.
- In our opinion the erection of:
  - Gathering Stations
  - Central Processing
  - Tank Farm
  - Metering
  - Pipelines
  - Water facilities
  - other infrastructure

  Is largely 'off the shelf' standard engineered items or areas of higher predictability.
- Development drilling needs further investigation on a probabilistic basis.
- We need to look at the time and cost elements used to calculate drilling costs

Conclusion: Development drilling represents the largest portion of Aishwariya Capex but in general we think the uncertainty of the expenditure is generally less than Mangala because of the smaller number of wells.

Aishwariya Opex

Cairn Operating Costs

Ashwariya Description	Q3-Q4 2007	2008	2009	2010
Manpower	1,227	3,272	3,272	3,272
Field Security	109	218	218	218
Well & Reservoir	1,935	3,467	3,242	2,495
Transport	89	178	178	178
Operating Consumables	1,053	1,763	1,392	1,284
Maintenance	505	1,009	1,009	1,009
HSE	103	206	206	206
Work	250	1,000	1,000	1,000
Insurance	100	200	200	200
G&A	100	200	200	200
PCO	55	115	109	101
Total Operating Costs	5,526	11,628	11,026	10,163

3rd Party Operating Costs

- We compare the Aishwariya project to several other international projects of a similar nature, e.g.:
  - onshore desert conditions.
  - similar reserves and production.
- The results show that Cairn opex stabilizes at $2.27/bbl compared to the Global average of $4.32/bbl.
- We note that 'Manpower' represents the largest portion of operating costs and would speculate that Indian Manpower costs are some of the lowest in the world.
- This is how we would explain the lower unit costs.
- This is backed up by Cairn having established an opex track record in India of less than $1.6/bbl in its Cambay Basin facilities.

Operator	Country	Project	Gross Reserves (MMbbl)	Peak Production (000 b/d)	No Wells	Project Lead Time (years)	Opex ($/bbl)
ENI	Algeria	ROD	300	78	17	4	4.23
ENI	Italy	Val d-Agri	468	100	42	6	3.40
Total	Algeria	Rhourd el Baguel	450	100	40	6	2.56
Murphy Oil	Malaysia	Kikeh	440	120	12	4	6.25
Murphy Oil	Ecuador	Block 16	305	75		6	5.18
Anadarko	Algeria	Ourhoud	250	230	80	7	
Average Data				**117**	**38**	**6**	**4.32**

	Q3-Q4 2007	2008	2009	2010
Total Operating costs ($MM)	5,526	11,628	11,026	10,163
	$2.66/bbl	**$2.73/bbl**	**$2.84/bbl**	**$2.27/bbl**
Production (MMbbl)	2.08	4.26	3.89	4.48

Conclusion: Cairn unit opex of $2.27/bbl is 36% lower than 3rd party calculated opex costs and we think this is largely due to lower manpower costs. We note the opex is slightly lower than Mangala ($2.75/bbl) and considering the smaller number of wells and less complex processing facilities (primary processing and Gathering centre only) – this reduction is reasonable and to be expected.

Aishwariya Development Drilling

Production History of Aishwariya Wells

	Aish-1Z OHDST1b FA1	Aish-1Z OHDST2 FA1	Aish-2Z OHDST2 FA4	Aish-2Z OHDST3 FA3	Aish-2Z OHDST4 FA1	Aish-4 OHDST1 FA5	Aish-5 OHDST1a FA5	Aish-5 HDST2 FA4	Aish-5 OHDST3 FA3	Aish-6Z CHDST1 FA5	Aish-6Z CHDST2 FA3/4	Aish-6Z CHDST3 FA1
Date	07-Mar-04	09-Mar-04	30-May-04	03-Jun-04	05-Jun-04	02-Aug-04	03-Sep-04	05-Sep-04	06-Sep-04	01-May-05	07-May-05	11-May-05
Interval Top (m)	1043	1027	1109	1074	980	1049	1132	1095	1049	1003	952	871
Interval Base (m)	1051	1033	1123	1081	988	1063	1147	1110	1055	1010	1002	888
NetPay (m)	2.0	2.6	11.0	4.6	2.6	18	12.2	12.2	4.5	6.7	25.3	4.5
Duration (hrs)	7	8.2	6.6	5.5	7.8	7	13.2	9.3	7.5	24	6	12
Flow Rate (bopd)	1100	900	120	440	155	700	950	175	530	1150	450	210
Choke x/64"	96	128	24	24	20	96	96	20	32	96	16	24
FTHP (psia)	60	53	25--55	95	100	110	95	50	56	80	290	65
Oil Quality (°API)	31.3	32.5	30.8	30.6	32.1	30.7	29	29	30	31	32.4	32
Oil Viscosity (cp)	7.6	8.0	20.0	14.8	8.0	24	22	20	14	22	15	7
Initial Pressure (psi)	1762	1743	1862.5	1812	1724	1765	1879	1846	1768	1714	1687	1704
Permeability(md)	3770	2533	486	3494	1543	1235	19085	1556	4305	2700	1380	790
Skin	-1.1	0.14	2.6*	4*	4.6*	5.7	0.66	8	2.99	-2.5*	-4*	-2.7
PI (b/d/psi)	2.6	1.8	0.53	1.9	1.24	1.4	10	1.28	2.66	3	11	2
			*Sand Production Observed									

Proposed P50 Profile (48MMbbl)

Date	Oil Production (000 b/d)	Fluid	Producers Wells (No)	Injectors Wells (No)	Total Wells (No)	Rate per Oil well (000 b/d)	Water Cut (%)
Dec-07	3.6	4	18	15	33	0.20	0%
Dec-08	11.7	15	18	15	33	0.65	16%
Dec-09	10.7	16	36	15	51	0.30	31%
Dec-10	12.3	20	36	15	51	0.34	35%
Dec-11	10.2	19	36	15	51	0.28	44%
Dec-12	8.7	17	36	15	51	0.24	48%
Dec-13	7.3	17	36	15	51	0.20	54%
Dec-14	6.2	15	36	15	51	0.17	58%
Dec-15	5.5	16	36	15	51	0.15	63%
Dec-16	5.1	16	36	15	51	0.14	68%
Dec-17	4.7	17	36	15	51	0.13	71%
Dec-18	4.3	17	36	15	51	0.12	74%
Dec-19	3.9	18	36	15	51	0.11	78%
Dec-20	3.4	17	36	15	51	0.09	79%
Dec-21	3.0	16	36	15	51	0.08	81%
Dec-22	2.8	16	36	15	51	0.08	82%
Dec-23	2.6	17	36	15	51	0.07	84%
Dec-24	2.4	17	36	15	51	0.07	85%
Dec-25	2.1	14	36	15	51	0.06	84%
Dec-26	2.0	14	36	15	51	0.06	85%
Dec-27	1.9	14	36	15	51	0.05	86%
Dec-28	1.8	15	36	15	51	0.05	87%
Dec-29	1.6	12	36	15	51	0.05	86%
Dec-30	1.4	10	36	15	51	0.04	84%
Dec-31	1.4	9	36	15	51	0.04	85%
Dec-32	1.3	10	36	15	51	0.04	85%
Dec-33	1.3	10	36	15	51	0.04	86%
Dec-34	1.3	10	36	15	51	0.04	87%
Dec-35	1.2	9	36	15	51	0.03	86%
Dec-36	1.1	9	36	15	51	0.03	86%
Dec-37	1.1	9	36	15	51	0.03	87%
Dec-38	1.0	9	36	15	51	0.03	88%
Dec-39	1.0	9	36	15	51	0.03	88%
Dec-40	1.0	9	36	15	51	0.24	88%
	48 MMbbl						

Phase 1 assumes 18 producers and 15 injectors drilled from Oct 06 – Oct 07 and this appear reasonable and achievable.

The next phase to peak production (12kbd) assumes additional 18 wells over next 2 years, e.g. 9 wells per year – also reasonable.

Commentary

Historic results

- We have shown the test results from the wells drilled on Aishwariya to date, as published by Cairn.
- These results relate to production testing of exploration and appraisal wells.
- The rates shown relate to individual formations.
- Production wells would be better optimized for efficient production from each formation.
- The recovery per well is only 300b/d at plateau (1500b/d for Mangala).
- This reflects the lower productivity (measured by 'PI' in the top table) of Aishwariya and this seems a reasonable assumption to us.

Future Predictions

- The production profile for the 48MMbbl 2P reserves case is shown left.
- This prediction is based on the output from a sophisticated computer simulation, as described with Mangala.
- The main uncertainty in the modeling relates to the last point – reservoir size.
- Cairn appears to have done everything feasible to make a fair prediction of production rates.
- Our simple calculations appear to back-up the claimed rates from the Aishwariya production wells.
- It therefore appears reasonable to us that a 12kbd plateau could be reached by 2011.

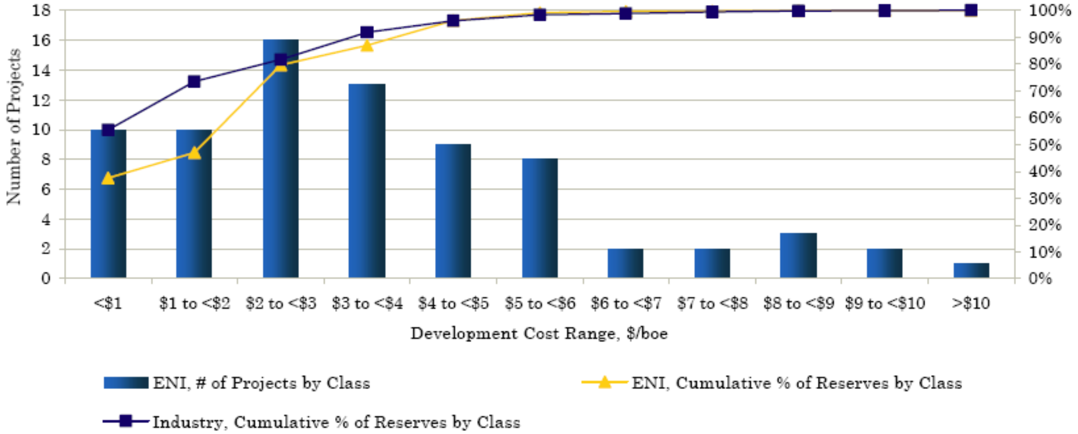
Water Handling

- Fluid is defined as oil + water.
- Water is produced rapidly after the water injected to maintain reservoir pressure 'breaks through'.
- The prediction of this phenomenon is a standard reservoir engineering problem.
- Computer simulation and laboratory work carried out by Cairn is standard practice and the results presented by Cairn appear reasonable.

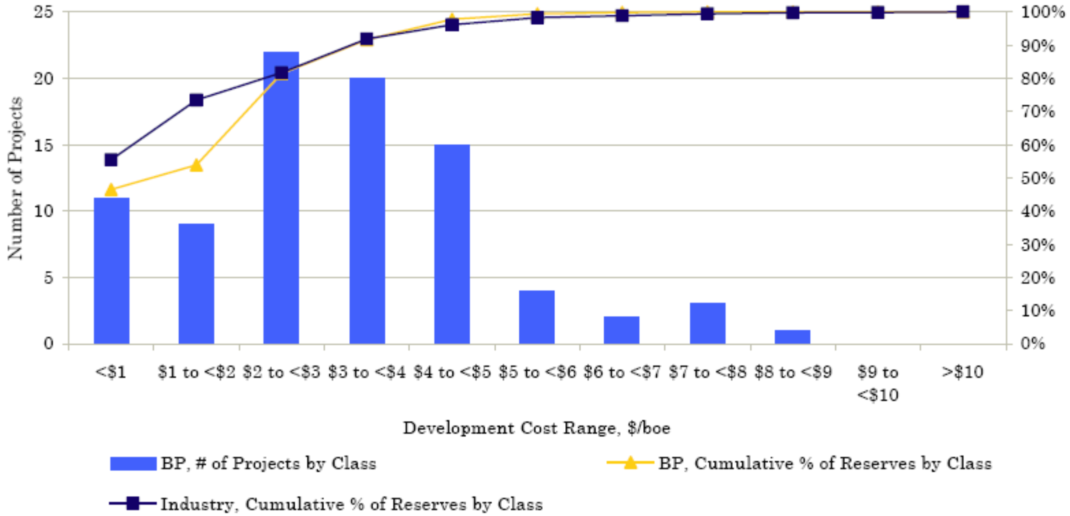
Conclusion: The oil and water production profiles presented by Cairn rely on industry standard methodologies that appear reasonable.

Project Cost Comparison

ENI Project Data



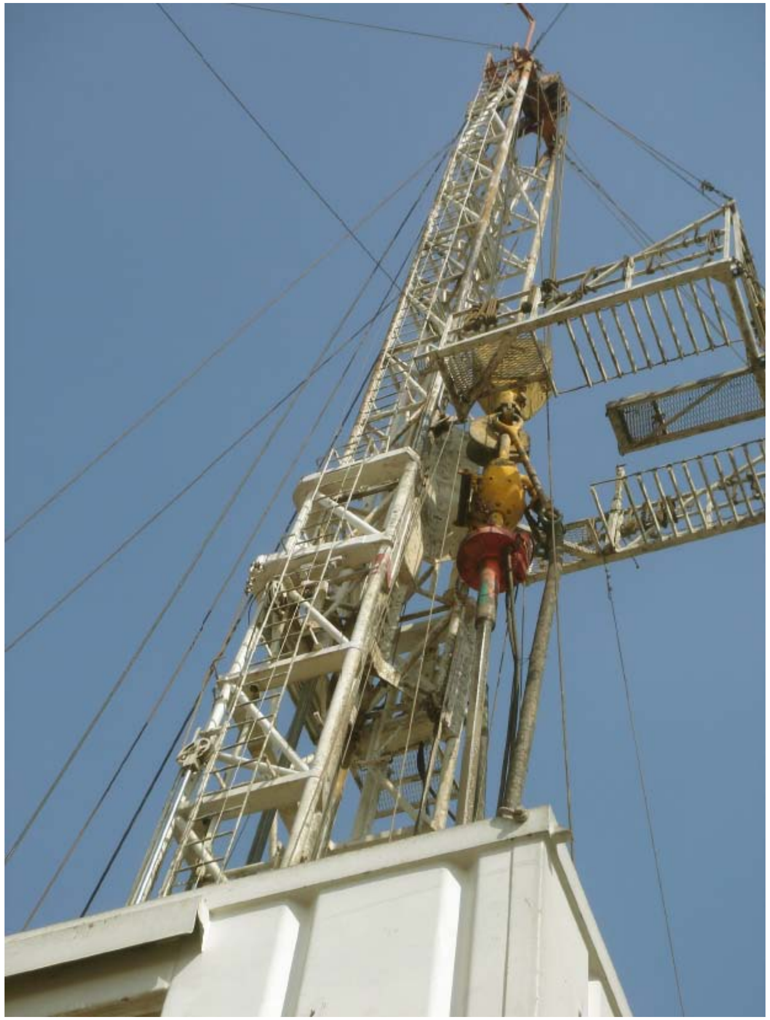
BP Project Data



Commentary

- We include this additional data to echo the points made on page 25.
- It shows ENI and BP data to confirm our benchmark $3.00/bbl for large project unit capex.

Rajasthan Fields Infrastructure



Hulf Hamilton Photo

Appraisal drilling on Bhagyam

Hulf Hamilton Photo

Mangala-1 discovery well head

Cairn has done this before in the Cambay Basin (on a smaller scale)

Hulf Hamilton Photo

Suvali processing plant (gas processing)

Hulf Hamilton Photo

Well heads on Lakshmi platform

Hulf Hamilton Photo

Lakshmi GA platform

Local Population is being managed

Hulf Hamilton Photo

School children at Rajasthan school that Cairn has funded

Hulf Hamilton Photo

Mothers of children in Rajasthan

Personnel

Al Stanton (Bridgewater), Katherine Tonks (CSFB), Bill Gammell (Cairn CEO) and Charlie Sharp (Jeffries) at Rajasthan school visit.

Richard Hulf (Author) on Lakshmi platform.