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# EXECUTIVE SUMMARY

Subsequent to the approval of Initial Development Plan for Dhirubhai-1 and Dhirubhai 3 gas fields in KG-DWN-98/3 (KG D6) block by the Management Committee in November 2004, lot of work has been done in this block to assess the overall hydrocarbon potential of the block in general and also the revised recoverable reserves associated within the Development Area.

This work includes but not limited to the following :-

a) Additional 3D seismic data acquisition of over 7600 sq. km.
b) Drilling of additional exploratory wells with extensive logging and well testing programmes resulting in a total of 13 gas discoveries
c) Drilling, and extensive coring of two development wells in the Development Area
d) Extensive studies based on additional data generated through (a), (b) and (c) above, e.g.
    - 2 ms re-processing and interpretation of seismic data
    - Simultaneous and stochastic inversion
    - Permeability modeling
    - Independent assessment of In-place volumes and reserves by international consultant

As a result of the works summarized as above, the hydrocarbon potential has increased considerably. Estimated potential for the entire block is currently estimated around 50 TCF. The 2P reserves for Dhirubhai-1 and Dhirubhai-3 gas discoveries have almost doubled to 11.3 TCF as against the approved Development Plan numbers of 5.32 TCF. These reserve estimates are expected to undergo further upward revision when the data of two Development wells already drilled is integrated with the current model and additional studies already completed or ongoing are concluded. These additional studies include :-

a) Core description of A10 and B7 wells
b) Lam count studies on cores (A10 and B7 wells)
c) Geological, Routine and SCAL core analysis (A10 and B7 wells)
d) High resolution sequence stratigraphy
e) High frequency imaging

Considering the overall potential of the block in general and current estimates of 2P recoverable reserves of Dhirubhai-1 and Dhirubhai-3 gas discoveries in particular, this Addendum to the Initial Development Plan for Dhirubhai-1 and Dhirubhai-3 gas discoveries is submitted for consideration and approval.

The Addendum proposes a plateau production corresponding to 80 MMSCMD of sales gas and increased gas production, collection, evacuation and handling facilities both offshore and onshore. The proposed facilities will be further upgradable to 120 MMSCMD, if required, through suitable flexibilities and integration provisions being incorporated in the design. This is with the view that the facilities should not become a bottleneck in case higher production levels become feasible as a result of the planned additional exploratory programme for the block including the Cretaceous prospects.

Major changes as proposed in the Addendum vis-à-vis the earlier approved Initial Development Plan are as follows :-

| | Approved Development Plan | Proposed as per Addendum | |
|---|---|---|---|
| | | Upto 2008-09 | Beyond 2008-09 |
| Recoverable reserves (TCF) | 5.32 | 11.3 | |
| Plateau production rate (MMSCMD) | 40 | 80 | |
| Total No. of Development Wells | 34 | 50 | |
| Phasing of Development Wells | 14 + 10 + 10 | 22 (18 + 4) | 9 + 9 + 10 |
| Subsea Manifolds | 10 | 6 | 6 |
| Deepwater PLEMs | 1 | 1 | 1 |
| Shallow Water PLEM | 1 | - | - |
| Control cum Riser Platform | - | 1 | - |
| Gas Evacuation pipelines from SWPLEM / CRP to Onshore Terminal | 2 x 24" | 3 x 24" | - |
| Gas Evacuation pipelines from DWPLEM to SWPLEM / CRP | 2 x 24" | 2 x 24" | 2 x 18" |
| Infield pipelines (from manifold to DWPLEM) | 10 x 14/16" | 6 x 16/18" | 6 x 16/18" |
| Well Flowlines | For 34 wells | For 22 wells | For 28 wells |
| Processing Trains & Capacity (MMSCMD) | 3 X 15 | 4 X 20 (with provision to add another two trains) | - |
| MEG Lines | 2 x 6" | 3 x 6" | - |
| Future Shallow water Compression Platform Capacity (MMSCMD) | 40 | - | 80 |
| Onshore Compression (72 barg to 98 barg) | - | 1 | - |

The revised CAPEX for the initial phase of development (upto year 2008-09) has been estimated as US $ 5196.58 MM based on July 2006 prices.

Utilization of the increased level of gas production is not expected to pose any problem in view of the large gap between the gas demand and the projected gas availability as earlier projected in the approved Development Plan.

Based on the current status of the project, when most of the longlead items and major installation jobs have been awarded, the schedule of First Gas by mid 2008, though extremely tight, is achievable.

RIL as Operator for the KG-DWN-98/3 (KG D6) block, on behalf of the Contractor, recommends and requests the Management Committee to consider this Addendum and accord approval of the same since it helps in achieving higher gas production levels required for the country's growing energy demand while maintaining the current project schedule of First Gas by mid 2008.

# SECTION – 1

# NEED FOR ADDENDUM

### 1.1. Background

Deepwater Block KG-DWN-98/3 (referred to as Block KG-D6) in Krishna - Godavari Basin off the East Coast of India in Bay of Bengal was awarded to Reliance Industries Limited (RIL) and Niko Resources Limited, Calgary, Canada (NIKO) under NELP-1 bidding round. RIL, as Operator of the block holds 90% of the participating interest and NIKO the remaining 10%.

The block covers an area of 7645 sq kms and its north-western boundary is about 40 - 60 kms southeast of Kakinada in Andhra Pradesh. Water depth in the block ranges from 400m to 2700m.

Exploratory efforts made so far in the block have resulted in 13 non-associated gas discoveries. These discoveries are mostly in upper Pliocene plays. The gas is biogenic in nature.

The Development Plan in respect of Dhirubhai-1 and Dhirubhai-3 gas discoveries was approved by the Management Committee on 5th November 2004. The approved Development Plan considered 2P recoverable reserves of 5.32 TCF with a total of 34 wells. The plateau production level was 40 MMSCMD. The Development Concept was based on subsea wells and facilities connected to onshore gas processing facilities with provision for future compression facilities located at shallow water compression platform. The schedule for the First Gas as per this plan is mid 2008.

### 1.2 Current Hydrocarbon Potential and Reserve Estimates

The Initial Development Plan was based on information of four wells (A1, A2-A, B1 and B2). The dataset included extensive log and MDT data in all the wells, however, the core data was limited to only A2-A well. Since the approval of the Development Plan, extensive exploratory activities have been carried out by way of additional 3D seismic acquisition of around 7600 sq. km. and drilling of additional exploratory wells. In addition to the data available as a result of these exploratory efforts, drilling of two development wells (A10 and B7) was advanced with extensive logging, MDT and coring programme which has helped in better understanding of overall hydrocarbon potential of the block in general and upgradation of reserves associated with Dhirubhai-1 and Dhirubhai-3 gas discoveries in particular.

The current estimates for the block potential as a whole (All drilled prospects and identified prospects yet to be drilled) is around 50 TCF. An independent assessment of Dhirubhai-1 and Dhirubhai-3 gas field reserves puts the 2P reserves as 11.3 TCF which is twice the reserve numbers as considered in the approved Development Plan (Refer December, 2005 report from Gaffney, Cline & Associates Ltd. – Annexure 1.1). These reserves are likely to undergo further upward revision since the current estimates have not considered results of A10 and B7 development wells where gross and net sand thicknesses and the quality of sands is found to be better than the original prognosis.

### *1.3 Increased Confidence Level*

The overall hydrocarbon potential of the block and the current assessment of reserves estimated through a consultant of international repute provide enough of confidence to propose this Addendum to the approved Initial Development Plan for Dhirubhai-1 and Dhirubhai-3 gas discoveries. The plateau production level proposed in this Addendum is 80 MMSCMD as against a production rate of 40 MMSCMD as per the approved Development Plan.

Since extensive exploratory programme is under consideration for KG D6 block, the potential of the block is likely to be higher than the current estimates. In that event, there is a possibility that production rates could be increased further. As such it is considered prudent at this stage to keep the option of upgrading the facilities for higher production rates. This aspect has also been addressed in the Addendum while designing the facilities. As per the current projections for gas demand and availability, utilization of the increased level of gas production in the Indian market is not expected to have any constraint provided the required gas transmission infrastructure is put in place. Reliance is already going ahead to lay a 48" dia. East West pipeline with a project completion schedule which will match with Dhirubhai-1 and Dhirubhai-3 gas field development.

### *1.4 Other Supporting Factors*

Based on the current status of ordering of long lead items and other work awards, it is felt that the proposed changes in the facilities and increased number of wells required for higher level of production have no impact on the project schedule for the First Gas by mid 2008.

# SECTION – 2

# SUBSURFACE

## 2.1 *Increased OGIP/Reserves Potential Dhirubhai-1 & Dhirubhai-3*

### 2.1.1 Advanced Reservoir Characterization

The approved development plan, with a 2P reserves base of 5.3 TCF, was based on a reservoir model generated two years back. This model used 3D seismic amplitude data as a soft constraint to estimate reservoir properties. With only four wells drilled,. the facies and petrophysical estimation in the inter-well space were primarily guided by amplitude attribute. Amplitude being an interface property, the property prediction using this data had its limitations and uncertainty.

Subsequently, the 3D seismic data was reprocessed and inverted by Western Geco and Fugro Jason respectively. The quantitative petrophysical interpretations were revised after integrating core data. Alternate petrophysical models were attempted to characterize thin bedded reservoirs and estimation of net pay thickness. Lam-count studies, high resolution sequence stratigraphy, non-destructive core description, process sedimentology, AVO-inversion, 2ms reprocessing of 3D seismic data and laboratory core analysis were some of the special studies carried out by engaging reputed international consultants and specialists. All these studies and data analysis improved the reservoir understanding and description (Fig. 2.1, 2.2 & 2.3). The prediction accuracy of fluid and rock property within the reservoir increased significantly (Fig. 2.4, 2.5 & 2.6) .These studies have indicated significantly higher hydrocarbon potential of Dhirubhai-1 & Dhirubhai-3. As a result, an independent OGIP/Reserves estimation was done by engaging Gaffney Cline & Associates (GCA) UK, a reputed international agency, during June-December 2005.

### 2.1.2 Revised OGIP/Reserves estimates by GCA

Gaffney & Cline Associates (GCA) of UK, an internationally reputed Resource and Reserves estimation agency was engaged by RIL to make an independent estimation of OGIP and Reserves of all D6 discoveries made upto April 30, 2005 including Dhirubhai 1 and Dhirubhai-3 gas fields. GCA has estimated Low, Best and High case OGIP of 5.7, 18.8 and 27.2 TCF respectively for AB channel complex comprising of Dhirubhai-1 & Dhirubhai-3 discoveries. The corresponding reserves estimated under different categories are as given below :

| GCA Study | Proved TCF | Proved plus Probably TCF | Proved plus Probably PLUS Possible TCF |
|---|---|---|---|
| Dhirubhai-1 & Dhirubhai-3 (AB Channel Complex) | 4.4 | 11.3 | 21.0 |

The best case OGIP and 2P Reserves estimates by GCA are significantly higher than the corresponding estimates presented in the initial development plan of 7.1 TCF and

5.3 TCF respectively. The 2P reserves of 11.3 TCF is 2.15 times more than the reserves considered in the current approved Development plan for Dhirubhai-1 and 3 fields.

The main reason for this difference is in the approach and methodology adopted by GCA based on their international experience in similar reservoir and geological setting up. Some of the reasons for this significant upside estimates are :-

a) Use of latest data all timed data, interpretations , analysis and studies upto 30th April, 2005
b) Geological modeling and concepts
c) Petrophysical Model and interpretation
d) Seismic reservoir characterization concept and calibration
e) Facies modeling and distribution within the channel and inter-channel area
f) Definition of the estimation limits and polygons including inverted seismic data

GCA's methodology and approach are discussed in its report submitted to RIL.

### *2.2 Other Known Discoveries*

Further exploratory drilling in the block has resulted in 9 (D6-C1, D6-D1, D6-F1, D6-K1, D6-K2, D6-M1, D6-G1, D6-E1 and D6-P1) additional discoveries having commercial quantities of gas accumulation. Commerciality reports for all these discoveries are already submitted to DGH for approval. Except for D6-C1, which proved hydrocarbon accumulation in Miocene, all other discoveries encountered gas accumulations in channel-levee-fan complexes of Upper Pliocene sequences. Some of these discoveries have multiple gas pools. The estimated OGIP volumes for these discoveries (excluding D6-P1) are as under :-

I. Low Case – 6.9 TCF
II. Best Case – 23.2 TCF
III. High Case – 35.4 TCF

All the discovery wells were tested through MDT and/or DST. Results of DST for some of the wells were very encouraging. Extensive MDT has been collected on all the wells. The flow rate for well D6-G1 was as high as 45.8 MMSCFD with 120/64" choke on DST. It is clear from the coring of D6-A10 and D6-B7, that the reservoirs of D6 are much more prolific than predicted through seismic and conventional log data. These sands are deposited in the similar depositional framework, therefore are likely to exhibit similar rock quality as seen in A10 and B7 cores Based on this evidence, the estimated OGIP for all these discoveries are likely to go up leading to higher recoverable reserves.

The P3 OGIP associated with all the above discoveries is 1.7TCF. This is likely to be upgraded to higher category with better understanding, re-processing and other studies. This will further add to the recoverable reserves and enhanced producibility.

All these discoveries are located nearby Dhirubhai-1 and Dhirubhai-3 respectively. The distances between the discoveries range from few km to maximum of 10-12 km. The development of all the above gas discoveries shall be taken up immediately following the development of Dhirubhai 1 & Dhirubhai 3 discoveries by integrating with the facilities proposed to be installed for Dhirubhai 1 and Dhirubhai 3 developments.

In addition, there are some intervals in the vicinity of wells G1, M1 and D1 which have not been penetrated by the well but show up prospective signatures both on conventional and inverted seismic volumes. These prospects therefore have upside potential, which are not included in the above mentioned volume estimates. The combined estimated upside potential around the above three discoveries is of the order of 1 TCF.

## *2.3 Other Potential Prospects*

### 2.3.1 Pliocene Prospects

Additional 3D seismic acquisition of 4179 sq km (Phase-II) and 3474 sq km (Phase-III) have been shot adjoining the 1822 sq. km first phase 3D survey area. Processing of Phase-II acquired data is complete and the Phase –III data is under processing. Based on the interpretation of the phase-II data, a number of prospects have been mapped both within the Pliocene and Cretaceous sequences.

The Pliocene prospects are the fan/lobe extension of the channel –levee complexes mapped and explored in the area covered by the first phase 3D API. The fans are quite extensive and have amplitude and AVO response characteristic of other accumulations. The deposits are more of sheet types and semi-confined reservoir system. A total of 19 prospects have been mapped and the locations are finalized for drilling. These 19 locations are aimed at exploring the pliocene fan /lobe complexes in the basinal part of the block. The combined OGIP potential of all these 19 prospects is 30TCF.

### 2.3.2 Cretaceous Prospects

Six prospects are mapped in the deeper cretaceous sequence. These are mostly structural prospects having potential of both oil and gas accumulation. The six mapped prospects are likely to have 1600 MMBO and 9 TCF of Gas in-place volumes. These prospects are likely to have huge thickness of reservoir sand deposition within cretaceous rift system .These plays are considered to have very high hydrocarbon potential, as an adjoining block has also proved oil and gas accumulation.

The prospects identified are close to the discoveries made with a separation distance of less than 10km. Distance from the shore range between 30-70 km. However their distance from the existing discoveries and inter prospect distance is very less. Putting these prospects on production through tie up with the existing system will be at a less cost to meet the requirement.

The estimated hydrocarbon potential from a total of 25 prospects is 39 TCF of gas and 1600 MMBO oil. About 25 well locations have been identified. These locations are expected to be drilled and explored in the coming years.

## 2.4 *Revised Base Case & Production Profiles*

### 2.4.1 Introduction

Subsequent to the OC approval of the development plan, various studies have been continued to further understand the reservoir characteristics. Primary among them are the revised petrophysical interpretation and the inversion studies. Based on such updated data, M/s GCA, an internationally reputed Reserve estimating agency, came up with a revised OGIP and Reserve figures as detailed in earlier section. These numbers were substantiated by the results of drilling of two development wells D6 A10 and D6 B7. These wells were extensively cored. The coring brought out that there is more net sands in the well then could be established from the available suite of logs including the high resolution FMI and OBMI logs.

With these new petrophysical Interpretations, an updated reservoir model/simulation model is being prepared. Meanwhile, for the purpose of studying the filed performance, a material balance based tank model has been prepared which is termed as "REVISED BASE CASE". This is in addition to the BASE, PESSIMISTIC and OPTIMISTIC cases presented in the Initial Development Plan.

### 2.4.2 Material Balance Studies: Revised Base Case

The production performance of the Dhirubhai 1 and Dhirubhai 3 gas fields is estimated using the Material Balance Equation (MBE) for gas reservoirs. A commercial Material Balance Simulator (MBAL) was used to make prediction runs for a tank type gas reservoir model for estimating recoverable gas reserves. Although the reservoir complexity and possible discontinuity is not captured in the material balance model, it is believed that this model adequately represents field performance. This confidence is from the fact that (i) It is a gas field (ii) No apparent faults or compartments in the reservoirs (iii) The results of the simulation model presented in the IDP were similar to the results of the Material balance calculations done earlier. A detailed flow simulation mode is meanwhile being prepared which will be submitted for perusal.

The tank model has been made considering 2P Reserves values estimated by GCA. GCA estimates that recovery from Dhirubhai 1 and 3 fields would be in order of 11.3 TCF.

### 2.4.3 Basic Data & Assumptions for the Production Profiles

The basic data and assumptions used for input into the MBE simulator are given below:

**Fluid Parameters:**

- Gas Specific Gravity: 0.556
- $H_2S$: 0.00%
- $CO_2$: 0.06 – 0.12%%

- N2: 0.00%
- Bg at Initial Pressure: 0.00483 rcf/scf @ 3335 psia
- Z factor at Initial Pressure: 0.912 @ 3335 psia
- Reservoir Parameters: Reservoir Temperature: 170.6°F @ 6278m TVDSS
- Reservoir Pressure: 3335 psia @ 6278m TVDSS
- Water Compressibility: 2.96x10-6/psi (from correlation based on water salinity of 31900 ppm)
- Rock Compressibility: 3.21x10-6/psi

Reservoir parameters have been established on the basis of analysis of logs and MDT data recorded in the D6 wells. Logs have also shown aquifer sands below the gas bearing zones. Relative permeability values have been calculated on the basis of the Core analysis. At this moment, in the absence of production history, it is not possible to quantify the exact aquifer effect.

**Number of wells considerations:**
50 producing wells are considered based upon two considerations. 34 wells are considered to produce reserves in the channel areas as mentioned in the initial development plan and 16 Wells are considered to produce the remaining reserves in the channel areas and the inter-channel areas. In the initial phase, 22 wells are required to produce at the rate of 80 MMSCMD. Phasing of remaining 28 wells will correspond to required tubing head pressure, to maintain the plateau rate of 80 MMSCMD sales gas.

Well Parameters :

- Inflow
  A Skin factor of 7 was assumed for calculation of the profiles. The parameters used for the inflow performance of the wells are as follows:

  - IPR: Forchheimer [Pseudo]
  - Darcy skin: 7
  - Non Darcy: 0.0176818 psi2/cp/ (Mscf / day) 2

- Outflow
  Outflow calculations were made for wells in water depth of 650 to 1200 m. Two sets of wells corresponding to A & B channels are simulated in the model. The properties of these two types of wells are as follows:

  - A wells : Tubing ID - 9-5/8", Max Production Rate - 200 MMSCFD
  - B wells : Tubing ID - 7", Max Production Rate - 100 MMSCFD

  However, the deliverability of A-channel wells and B-Channel wells is expected to be around 350 MMSCFD and 200 MMSCFD respectively. The well completions are proposed to be designed accordingly, so as to have the flexibility to step-up the production from the producing wells, in the event of short-term closure of few wells.

Outflow curves were generated using commercial software (WellFlo) for input into the MBE simulator.

Tubing Head Pressure:

The material balance model gives a single uniform average tubing head pressure for every time-step. Actual THP's could vary depending on reservoir complexity. The MBAL simulator assumes that the well flow is not constrained by the facilities. The primary compression facilities at the future Compressor platform shall be available to produce the wells up to a minimum wellhead pressure of 900 psi, based on which the production profile is presented. However, the wells can produce at pressures below 900 psi (say upto 400-450 psi) resulting in additional recoveries by installing booster compressors at the future compression platform.

### 2.4.4 Production Profile

Plateau period profile was run keeping a maximum gas rate of 80 MMSCMD. The plateau period for the profile is 8 years. Gas recovery of 11.03 TCF was achieved, in 14.25 years.

| Time (date m/d/y) | Cum Years | Reservoir Pressure (psia) | Gas Recovery Factor (percent) | Gas Rate (Production) (MMscf/day) | Gas Rate (Sales) (MMSCMD) | Cum Gas Sales (Bcf) | Number of Producers |
|---|---|---|---|---|---|---|---|
| 7/1/2008 | 0.00 | 3335 | 0 | 1448 | 40 | 0 | 9 |
| 12/1/2008 | 0.42 | 3285 | 1 | 1810 | 50 | 216 | 12 |
| 3/1/2009 | 0.66 | 3252 | 3 | 2172 | 60 | 375 | 18 |
| 12/1/2009 | 1.42 | 3124 | 7 | 2895 | 80 | 957 | 22 |
| 7/1/2010 | 2.00 | 2988 | 11 | 2895 | 80 | 1555 | 22 |
| 7/1/2011 | 3.00 | 2780 | 18 | 2895 | 80 | 2586 | 31 |
| 7/1/2012 | 4.00 | 2573 | 25 | 2895 | 80 | 3619 | 40 |
| 7/1/2013 | 5.00 | 2359 | 32 | 2895 | 80 | 4649 | 50 |
| 7/1/2014 | 6.00 | 2152 | 39 | 2895 | 80 | 5680 | 50 |
| 7/1/2015 | 7.00 | 1949 | 46 | 2895 | 80 | 6710 | 50 |
| 7/1/2016 | 8.00 | 1736 | 53 | 2895 | 80 | 7744 | 50 |
| 7/1/2017 | 9.00 | 1510 | 60 | 2172 | 60 | 8774 | 50 |
| 7/1/2018 | 10.00 | 1351 | 65 | 2172 | 60 | 9547 | 50 |
| 7/1/2019 | 11.00 | 1231 | 69 | 1447 | 40 | 10127 | 50 |
| 7/1/2020 | 12.00 | 1146 | 71 | 724 | 20 | 10515 | 50 |
| 7/1/2021 | 13.00 | 1091 | 73 | 724 | 20 | 10772 | 50 |
| 7/1/2022 | 14.00 | 1054 | 75 | 362 | 10 | 10982 | 50 |
| 10/1/2022 | 14.25 | 1048 | 75 | 0 | 0 | 11014 | 50 |

The above profile is shown in Figure 2.7

### 2.4.5 Conclusions from Material Balance Study for Revised Base Case

The field is capable of producing 80 MMSCMD with 22 wells initially. Additional 18 wells will be required to maintain the plateau of 80 MMSCMD upto 9th year of production.

Actual production profile would be dependent on the market scenario prevalent at the time of starting of the production.

As per the current understanding of the reservoir data, the field recovery is maximized with uniform drainage. The final well locations would be firmed up once additional data (viz. inversion data) are incorporated in the model.

# SECTION – 3

# DRILLING AND WELL COMPLETION

Detailed write-up for Drilling and Completion has been provided in the original Development Plan earlier approved by the management committee. The major details provided remain same. However, changes and certain additional information relevant to the Project are summarised below:

## *3.1 Drilling Programme*

The approved Initial Development Plan was for a plateau production of 40 MMSCMD. As per details and justifications provided in Section 1 & 2 of this document, the addendum is submitted for a plateau production of 80 MMSCMD. In the approved Initial Development Plan, requirement of total 34 Wells was envisaged for a plateau production of 40 MMSCMD where as in the Addendum for the enhanced plateau production of 80 MMSCMD, requirement of total Wells is envisaged as 50 Wells.

In the initial phase, a total of 22 Wells are required to produce at the rate of 80 MMSCMD. Phasing of the remaining wells is planned corresponding to the required tubing head pressure to maintain the plateau rate of 80 MMSCMD as detailed in Section-2.

Out of 22 wells in initial phase, 6 re-entry wells have been considered (4 Exploratory wells D6-A1, D6-A2A, D6-B1, D6-B2 and 2 Development wells D6-A10A and D6-B7 for which drilling was advanced to acquire core and the log data). Remaining 16 wells are required to be drilled. As per present schedule, drilling of these new wells will start in October-November 2006 and all the 16 wells will be drilled by Jan-2008.

Well Completions will start from October-November 2007 (when the SS HXT will be available for running). As per the present plan, one deepwater rig would be deployed for Well Completions starting from October-November 2007. Another rig would be deployed for well completions from May 2008.

## *3.2 Deep Water Rig*

Globally, Offshore activities (Exploration as well as Development) are seeing a continuous up-surge in the recent past and the trend is likely to continue. With this, the demand-supply position for all the assets and services required for these activities has tightened and the unit rates have escalated to new highs. In some of the cases, the demand has superseded the supply creating a situation of non-availability of assets and services in time. It is the case with Offshore Rig market also. In today's rig market, rigs are not available as many of the rigs are on long term existing contracts and commitments have been made for the future contracts. This has created not only non-availability of the rigs but also the day rates have increased substantially, especially for the deep water rigs where the increase is up to 200%. Same is true for all the associated equipment, tools and services.

RIL has, however committed 3 deep water Rigs to ensure that the development well drilling and completion schedule can be met. Water depth in the initial phase of development is up to 1200 m. In view of this and advance actions taken by RIL, availability of suitable Rig (s) for development drilling is not considered a threat in meeting the schedule as indicated in 3.1 above, expect that we may have to adjust the exploratory drilling commencements for various deep water blocks to some extent.

### *3.3 Well Design and Planning*

Most of the new D1 (A-channel) wells have the initial production potential of around 400 MMSCFD. Considering this, adequate flexibility is being kept in well design to enable up to 9 5/8" Tubing completions.

Depending on Cased Hole or Open Hole completions, following casing policy will be used for the new Development wells.

OPEN HOLE COMPLETIONS:

| Casing Size | Specifications | Setting Depth (m) | Remarks |
|---|---|---|---|
| 36" | 1.5" WT, 553 ppf, X-52 | 65 m below sea bed | |
| 20" | 0.812", 179 ppf, X-56 | 400-600 m below sea bed | To get sufficient LOT/FIT to meet specific well trajectory |
| 13 5/8" | 0.625", 88.2 ppf, P-110 | Approx 125 m above Reservoir top | 12 ¼" or required size open hole will be drilled below 13 5/8" casing for completions. |

Provision for 16" Liner is being kept to enable setting 13 5/8" casing to the required depth above reservoir top as a contingency arrangements. Further, use of thicker wall casing is being considered keeping in view the challenges associated with reservoir compaction and subsidence and to ensure casing integrity.

CASED HOLE COMPLETIONS:

| Casing Size | Specifications | Setting Depth (m) | Remarks |
|---|---|---|---|
| 36" | 1.5" WT, 553 ppf, X-52 | 65 m below sea bed | |
| 20" | 0.812", 179 ppf, X-56 | 400-600 m below sea bed | To get sufficient LOT/FIT to meet specific well trajectory |
| 13 5/8" | 0.625", 88.2 ppf, P-110 | In over burden to optimize OH section | |
| 10 ¾" | 0.625", 65.5 ppf, P-110 | To final TD covering reservoir section | |

Provision of completing the wells with 10 ¾" / 9 7/8" Liner would also be kept to enable use of 9 5/8" Tubing in upper completions.

One of the major challenges for the Well Design is the issues related with Geo-mechanics. Considering the criticality of this, RIL had engaged Schlumberger for carrying out Geomechanics Study of D-6 field in three phases. Work related to phases I, II and III has been completed.

As per the results of Phase II and preliminary results of Phase III Geo-mechanics studies, Dhirubhai-1("A" channel) wells could go up to 5% or more compaction in some of the critical areas in the reservoir section as the reservoir depletes. In case Dhirubhai-3 ("B" channel) wells it could be within about 4%-5%.

Wells are required to be designed in such a way that the casing string is strong enough to sustain the additional loadings due to compaction and subsidence (due to depletion in reservoir pressure during the production life of the field).

At this stage, based on the validation of geo-mechanics study, casing integrity checks and the casing policy followed in some of the similar developments, the casing policy as indicated above has been selected. Further discussions on Geomechanics are included in Completion section.

## *3.4 Well Completions*

### 3.4.1 Completion Challenges

KG-D6 Development Project, being in deep waters, having unique geological setting and reservoir characteristics, is a challenging Project and first of its type in India. As detailed in the approved Development Plan, the major reservoir systems identified in the block are submarine channel-fan complexes. The channels are mostly sinuous with multiple channels stacked together resulting in both vertical and lateral aggradations. Different play types include channels facies, over-bank and submarine fans.

Channel geometry and facies distribution envisaged in different parts of the block through seismic imaging has been confirmed by drilled wells, which encountered stacked channel complexes of up to 350m gross thickness. Stacked channels are flanked by levees, splays and over banks. Sands are highly unconsolidated; vary in grain size and distribution varying from thick to thin bedded sands. The permeability variation is from tens of milidarcy to few darcy across the reservoir section.

The unique reservoir features as stated above, pose lot of challenges for selecting optimum Well Completion design. Some of the major challenges for selecting the optimum Well Completion design are:

1. Sand control (Sand face completion design)
2. Reservoir compaction & Subsidence & its bearing on lower and upper completion design.
3. Big bore completion: 9 5/8" tubing. (For high rate gas production (350 MMSCFD)

4. Reservoir monitoring system.

Keeping in view the reservoir and geological features of reservoir sands, very effective and proven sand control measures in the Lower Completions is considered a must. Options available for sand face completions are Cased Hole or Open Hole. Both, Cased Hole Frac Pack as well as Open Hole Gravel Pack are being used world wide. Both are effective and proven sand control methods.

Plans are to utilize proven but the state of the art equipment, tools & technologies used in deepwater gas developments around the world. The drilling and completion efforts will focus on reliability and longevity of wells to meet the major challenges as listed above in the completion design in the most cost effective manner on the life cycle basis to minimize well intervention requirements.

### 3.4.2 Well Completion Design

The completion design for the Development wells in Dhirubahi-1 and Dhirubhai-3 Development Area will make provision for the following :

- Horizontal sub sea trees will be used with the tubing hanger landed off in the tree spool (HXTs may be nominally 7inch x 2inch – for wells completed with 9 5/8 inch tubing – or 5inch x 2inch for the balance of the wells).

- The production casing would be run to TD in case of cased hole completion & to reservoir top in case of open hole completion.

- Three possible production tubing sizes are being considered (depending upon individual well productivities) namely 7", 9-5/8" or a combination of the two.

- Continuous reservoir monitoring system i.e. Down Hole Pressure Temperature (DHPT) gauges (2 nos.)/ Fiber optic pressure and temperature gauges along with gauge mandrel. Fiber optic based sand face temperature monitoring system across sand face in the reservoir, if available with required Qualification testing with proven track records to meet the Project schedule.

- One Surface Controlled Subsurface Safety Valve (SCSSV) with single or dual control line/ lines based on the results of the studies presently being undertaken.

- Mitigation of sand production (Frac-Pack, Open Hole Gravel Pack, HRWP etc.)

The design has to be robust enough to sustain reservoir compaction over the entire production life of wells.

Considering the challenges as stated in 3.4.1 above and the fact that optimum completion design of these wells is one of the most vital factors for the success of development of Dhirubhai-1 and Dhirubhai-3 gas fields, RIL has awarded the work for Well Completion Design study through major Service Companies to arrive at the final design options for Dhirubhai-1 and Dhirubhai-3 Development wells.

The Completion Design studies carried out by the Companies shall be finally evaluated internally and also through a third party / specialist to select the best suited optimum design for Dhirubhai-1 and Dhirubhai-3.

### 3.4.3 Flow Assurance

The laboratory analysis data of well fluid samples from initial exploratory / appraisal wells in Dhirubhai-1 and Dhirubhai-3 have been used as inputs to predict the formation of hydrate, salt, scale and wax utilizing industry standard software/practices. Based on the production chemistry, salt, scale or wax formation tendencies are not anticipated.

The temperature and pressure profiles during production cycle were generated and used as input to predict the Hydrate formation tendencies within the well bore. It was found that the flowing temperature and pressure profiles during the flowing conditions are well beyond the hydrate-forming envelope. However during well shut-in period, when the gas and water in the well will get segregated & after temperature profiles corresponding to the geothermal gradient of the well at high well shut-in pressure, gas hydrates may form in the well up to a depth of 400-450m below the sea bed.

Continuous injection of MEG (Mono Ethylene Glycol) is envisaged down stream of the choke in the flow lines to mitigate flow assurance related risks in sub sea gas production pipeline network. When the wells get closed due to any reason, MEG will be injected upstream of the choke, which will dumped in to the well (above SCSSSC) to prevent the hydrate formation in the well.

As a safety and well integrity measure, Surface Controlled Sub Surface Safety Valve (SCSSSV) will be installed below the hydrate formation depth. The hydrate formation depths were calculated based on well shut in pressure and static geothermal gradient conditions.

### 3.4.4 Reservoir Compaction

As stated in 3.3 above, one of the major challenges for well design is the issues related with Geomechanics i.e reservoir compaction and associated subsidence when the reservoir pressure gets depleted during the production life of the field. Considering the criticality of this, RIL has engaged Schlumberger for carrying out Geomechanics Study. A third party has validated phase-I and Phase-II studies.

The key findings of the Geomechanical studies are listed below:

- The threshold depletions at which pore collapse and inelastic compactions are likely to commence are in the order of 200 psi. This could result in twice the reservoir compaction that would otherwise occur when the reservoir behaves elastically.
- Compaction & subsidence can be expected from the onset of depletion in the field.
- Maximum compaction in the D6 reservoir is expected to be around 21ft over the life of field, assuming average depletion of 2300 psi.

- Based on the analogues, the greater part of this compaction may be transmitted through the overburden. Thus, significant seabed subsidence should be observed.
- Maximum sea bed subsidence above the D6 reservoir is expected to be around 18 - 20 ft.
- There will be virtually no stretch occurring in the over burden, and the over burden incapable of providing any significant bridging to the compacting reservoir.
- Reduction in the horizontal stresses in the depleting reservoir layers will be in the order of 67% of the depletion.
- No hot spots appear to exist that might cause particular problems for drilling, either now or later in field life.
- Dhirubhai-1 ("A" channel) & Dhirubhai-3 ("B" channel) wells can see 3.25% average reservoir compaction in thick & thin/ laminated sands and no compaction for shale sections in the reservoir. However in some of the critical areas of the reservoir so called "hot spots" the reservoir compaction is up to 5%.

Based on Geo-mechanics study the reservoir compaction at well locations D6-A1, D6-A2-A, D6-B1 and D6-B2 are tabulated below:

| Well | A1 | A2-A | B1 | B2 |
|---|---|---|---|---|
| Gross interval thickness (m) | 303 | 285 | 207 | 57 |
| Net Thickness (m) | 112 | 86 | 69 | 46 |
| % Compaction strains corresponding to 2900 psi depletion | 1.71% | 1.66% | 1.86% | 1.74% |
| % Compaction strains corresponding to 2300 psi depletion, which corresponds to reservoir abandonment pressure | 1.36% | 1.32% | 1.47% | 1.38% |

**3D FEA analysis work done by all the service companies:**

The 3D FEA modeling and well bore integrity work has been carried out by service companies by considering well configurations and completion schematics for open hole gravel pack and cased hole frac pack for Dhirubha-1 ("A" channel) and Dhirubhai-3 ("B" channel) wells. They have analyzed all the possible failure mechanism listed below:

1) The dogleg and ovality of the completion equipment, which is relevant to remedial intervention options and installation of additional equipment inside the casing / liner and screen.

2) The compression and shear stresses on screen, which assesses the possible damage to the screen or open hole completion.
3) The compression and shear stresses on casing / liner and screen, which assesses the possible damage to the casing of the cased hole completion, and the protective function of the casing / liner.
4) The possibility of the buckling of the completion equipment.
5) Identification of other failure mechanism, if any.

The conclusion from the 3D FEA study is presented below:

- Although initial yield may occur within first 30% of final reservoir compaction, the tube materials can sustain large plastic strains so the tubes do not fail.
- The computed maximum plastic tensile and / or shear strains are less than 2%, which is nowhere near rupture.
- Inclination is beneficial, but not much difference until deviation larger than 30 Deg.
- Vertical wells are likely to experience bending and bulging (increased diameters), inclined wells go elliptical with some loss of diameters. However diameter change is minimal.
- The lower completion string in the worst case (vertical) is still stable even for twice the estimated vertical compaction.
- For the considered reservoir rock strength, no damage zone was computed.
- No failure of the base pipe & screen has reported.
- No Dogleg severity and hole ovality has been reported for any well angle.
- Both cased hole and open hole completion options are withstanding to reservoir compaction and subsidence associated loads.

### 3.4.5 Reservoir monitoring system

**Reservoir monitoring requirement :**

**Genesis:**

As stated earlier, the KG D6 reservoir system is a complex reservoir system having a multitude of channel levee complex in no particular order. The producing sands can be broadly classified as thick and thin sands, which can be both clean as well as dirty in nature. Further, these sands are having a considerable lateral extent while some of the sands may be discontinuous. The co-relation between the various producing packs has continued to be elusive till date and could take substantial production history for better understanding.

Under such circumstances, it is imperative that a proven and reliable real time reservoir monitoring system is installed to enable recommending an optimal exploitation of the reservoir. The system is expected to provide data for corrective as well as preventive actions for any reservoir related problems and developing proper depletion strategy.

A typical well profile–sand thickness, contributions, water expected :

As mentioned earlier, a typical well will encounter a very heterogeneous set of sand packages. It will be a combination of thick clean sands with multi darcy permeability at some places and then sand laminations few millimetres to centimetres thick at some other places with few mili darcy or few hundreds of mili darcy permeability. Some of them may be laterally extensive while some would be of limited lateral extent.

The above scenario means that initially the thick sands would be having major contribution to the well production while thin laminated sands may not even contribute or may have negligible contribution to the production. The draw-down could be as low as 20 – 40 psi. When the thick sands deplete, the thin sand contribution may increase. Further, depending upon the lateral extent/continuity of the individual sand packs (some of them few cm thick), some of them would cease to produce at different point in the life of the well. Simulation studies based on limited data do not indicate water production until late in the life of the well.

The intention is to capture these events, efficiently manage and exploit the reservoirs.

### Objective of reservoir monitoring system:

The reservoir monitoring system is intended to be installed in the wells for transmitting down hole parameters (Pressure and Temperature) up to the surface on real time basis. The basic objective behind installing reservoir monitoring system in D6 sub sea wells is to monitor real time sand face temperature and pressure from the well across various producing sand bodies in the reservoir.

The data collected are intended to be used to collect and analyze the following:

1. Determine the sand face completion efficiency (infer open perforations in frac pack and hot spots in gravel pack).
2. To determine productivity variations over the time due to compaction/ permeability reduction/ depletion.
3. The pressure drops between surface and the bottom-hole gauges, which are placed above the packer, to determine the condition and performance of the upper completion.
4. Well shut-ins allow the skin to be determined.
5. Early water breakthrough if any and its early detection.
6. To infer the contribution of individual sand packs and inter sand / inter well connectivity.
7. Interval depletion and field connectivity.

### Reservoir monitoring system availability:

Following are the options considered for reservoir monitoring system:

- **Distributed / Array temperature sensing (DTS / ATS) across sand face:**
  - ➢ Maximizing total recovery of hydrocarbon reserves

- Estimate relative contributions of all zones penetrated.
- Early detection of deviations from optimal performance.

- **Permanent down hole gauges (DHPT):**
  - Determination of productivity variations
  - Monitor condition and performance of upper completion
  - Determination of skin to assess performance of gravel pack

**System availability:**

- **Electronics:**
  - DHPT Gauge available with proven track record
  - ATS / DTS not available

- **Fiber Optic :**
  - DHPT gauge available with proven track record with vertical Xmas Trees
  - DTS / ATS not available for sub sea environment. Under various stages of development and qualification testing

- **Acoustic:**
  - DHPT gauges not available for sub sea gas field with proven track record.
  - DTS / ATS not available

**Best-suited option for KG-D6:**

The best suited reservoir monitoring system for D1 & D3 fields will be selected based on the results of ongoing studies.

# SECTION - 4

# DEVELOPMENT FACILITIES

## *4.1 Background*

The Initial Development Plan, as approved by the Management Committee, was based on Conceptual Engineering & FEED studies carried out by Aker Kvaerner and was for 40 MMSCMD plateau rate.

Following facilities were considered in the Initial Development Plan for Dhirubhai – 1 and 3 to cater to a plateau production rate of 40MMSCMD:

- Drilling and completion of 34 development wells
- Cluster Manifolds – 10 nos.
- Deepwater Pipe Line End Manifold (DW PLEM)
- Shallow water Pipe Line End Manifold (SW PLEM)
- Deepwater Infield pipelines connecting the manifolds to the DWPLEM.
- Two24" dia main evacuation pipelines from the DWPLEM to Onshore Terminal (OT)
- Well Flowlines connecting individual wells to the nearest manifold.
- Control System located at OT through umbilicals starting from OT to individual wells
- Future Shallow Water Compression Facility
- Onshore Gas Processing Terminal (OT)

## *4.2 Additional Studies/Surveys*

Subsequent to above FEED, significant amount of data/information was obtained, mainly in following areas:

### 4.2.1 Sub-surface

- Increased Potential in Dhirubhai 1 & 3
- Additional discoveries outside Dhirubhai 1 & 3 development areas and their potential
- Other Potential Prospects - prospects identified within extended 3D areas and corresponding prognosticated resources

### 4.2.2 Surveys

- Pipeline hydraulic/hydrodynamic data in river section (from LFP to 20 m water depth below Chart Datum)
- Geo-technical/soil investigation data from LFP to 100 m below Chart Datum
- Bathymetry and Geophysical surveys from LFP to 50 m water depth below Chart Datum
- Deepwater Soil Investigation data at the potential manifold locations
- Geo-hazard Survey

Considering the production profile as given in Section 2, which is for 80 MMSCMD plateau rate, based on the additional discoveries outside Dhirubhai-1 and Dhirubhai-3 Development Area and the other potential prospects, which may result in high pressure gas discoveries, gas discoveries with different composition etc., it is imperative that facilities installed cater to all such future demands.

In addition to above, the additional information obtained by way of surveys, as mentioned in Section (4.2.2) above, needed consideration.

It was, therefore, considered essential to integrate the above additional information (since FEED) in the design of facilities proposed to be installed for Dhirubhai 1 and Dhirubhai 3 development.

While carrying out the above and prior to committing significant expenditures on major contracts of procurement, fabrication, installation etc., it was considered prudent to have a final review of the various development options studied during conceptual engineering and validate whether the recommended development concept (of subsea tie-back to beach) was still the most techno-commercially preferred option. This was primarily required to see whether (a) Technological Advancements, if any, since the earlier FEED study had any bearing on the development concept selected earlier and (b) Schedule risks if any.

In view of above, a FEED Update study was carried out to make the necessary modifications/changes/amendments if any on the design concept developed earlier.

### *4.3 Additional Development Facilities*

Based on FEED Update study and increased production potential, following additional facilities are envisaged to handle and process 80 MMSCMD of gas with a provision for expansion to 120 MMSCMD and are proposed to be included in the development of Dhirubhai-1 and Dhirubhai-3 gas fields.

(i) Development Wells - Drilling and completion of additional 16 development wells
(ii) A Control cum Riser Platform (CRP) and a Flare Platform at 100 m water depth thereby eliminating the SW PLEM envisaged earlier
(iii) One 24" dia main evacuation pipelines from the Control & Riser Platform to Onshore Terminal (OT)
(iv) One 6" dia MEG pipeline from the OT to UDH
(v) One DWPLEM with provision to connect up to Four manifolds
(vi) Twin 18" mid-water pipelines from second DWPLEM to CRP
(vii) Two manifolds and associated deepwater pipelines
(viii) One SDA and Two SDU's
(ix) Upgradation of OT to handle and process 80 MMSCMD of gas with a provision for expansion to 120 MMSCMD of gas
(x) Upgradation of future shallow water compression facility to handle and compress 80 MMSCMD of gas

(xi) Vent System for hydrate remediation

From schedule standpoint, the additional facilities do not pose any constraint in achieving the First Gas target date of mid 2008. This has been further elaborated in the Schedule Section.

A detailed description for item no (i) has been provided in Section 2 & 3. The remaining items are described in subsections given below.

### 4.3.1 Control cum Riser Platform

The FEED update study brought out that the development concept recommended earlier (of subsea tie-back to beach) was still the preferred development option. However, based on various discoveries made and their potential, it is very likely that the initial production could be increased from the originally projected plateau level of 40 MMSCMD to 80 MMSCMD or more. While initial production would be from the Dhirubhai 1 and Dhirubhai 3 development areas, other discoveries could be brought on production progressively to maintain the plateau rate, even before the compression platform is installed. Some of the discoveries could also be of higher pressure than the pressure rating of currently designed system. As such, it is worth keeping additional flexibility – both from short term and long term viewpoint, within the existing design to handle higher gas rates.

To incorporate the above and other associated benefits, the FEED update study recommended installation of a Control cum Riser Platform at 100 m water depth and eliminating the Shallow Water PLEM envisaged earlier.

All topside equipment of Subsea Control System, which was originally proposed to be located at the OT, is now proposed to be relocated at the CRP. The two main multiplexed electro-hydraulic umbilicals will now originate at the CRP instead of OT. Therefore, all the control hydraulics will be shifted to CRP. Twin subsea power and communication cables will run from the OT to the CRP. The main functions of the CRP will be as follows:

- House topside equipment of Subsea Control System for control of subsea wells, manifolds and DWPLEM
- Import risers (HP), provisions for spec. break and manifolding arrangement to handle gas from future high pressure (HP) prospects.
- Flare system and bridge connected flare platform with flare tower
- PLEM functions located at deck level for import / export risers.
- Supply corrosion inhibitor for injection at wellheads
- Diesel driven generators to serve as back-up for the main power cables from OT.
- 20-men accommodation
- Helideck
- Associated utilities (sea water, fresh water, drain, diesel, etc)

The benefits associated with the introduction of a Control cum Riser Platform are as under:

- From a schedule standpoint, the critical path is installation of pipelines and main umbilicals in the river section. RIL had carried out an independent validation of the Project Schedule to identify the schedule risks. The review brought out that installation in the river section is the most critical area from a schedule standpoint. The risks get compounded as all the installation works in the river section has to be carried out in a very short weather window of 4 months.

  This risk will reduce to a great extent, if the main umbilicals are run from the CRP to the UDH and not from the OT. The shorter main umbilicals would eliminate any splitting of the main umbilicals and avoid any subsea splice, which could have been otherwise required if the main umbilicals were run from OT. This however, introduces laying of 25 km power/signal cables through the river section, but is preferred over laying two main umbilicals through the river section from installation point of view, as the overall weight reduction is expected to be around 25-30%.

- As potential discoveries outside the current development area of Dhirubhai-1 and Dhirubhai-3 may include high pressure discoveries (reservoir pressures in excess of ANSI # 1500 rating), introducing a CRP adds definite advantage, as it provides flexibility to allow pipeline specification break at the CRP topside and use a derated pipeline system (existing 24" lines) downstream of the CRP. This is essential, if these discoveries are to be connected prior to installation of the compression platform.

- The trenching requirements in the river section will get reduced due to elimination of main electro-hydraulic umbilicals in this section.

- Increase in the number of potential vessels for umbilical installation purposes, since the main electro-hydraulic umbilical installation in the river section gets eliminated.

- It is perceived that the chances of an umbilical failure are higher in the river section than in the deepwater section. Therefore, the failure risk of main umbilicals in the river section will get reduced.

### 4.3.2 Third 24" dia Main Evacuation Pipeline

The original FEED design was based on 40 MMSCMD plateau rate, and accordingly, twin 24" lines from SWPLEM to OT were considered; which however, had the capacity to go upto 90 MMSCMD with significant high amount of compression power at offshore.

Since, the design needed to be upgraded to handle 80 MMSCMD with provision to expand upto 120 MMSCMD, it has been concluded that the twin 24" lines from SWPLEM to OT (as per original FEED) could not handle such volumes. Therefore, there is a need to either increase the size of the pipelines or install additional pipeline.

Out of these two options, it is considered prudent to install a third 24" pipeline from CRP to OT, primarily for the reason that, in case any rich gas is discovered, it is not advisable to mix this rich gas with the gas from Dhirubhai-1 and Dhirubhai-3 gas fields and suitable flexibility needs to be built into the system to process / transport this rich gas separately and derive value-added components from rich gas in an optimal way.

A separate third 24"pipeline between OT and CRP will also assist in increasing the plateau capacity beyond 40 MMSCMD, reducing offshore compression power requirements.

Since a third 24" line is envisaged, it is prudent to complete all pipeline installation in the river section during the initial development campaign, as it will not be feasible to lay additional pipeline in the river section at a later stage (risk of damaging originally installed pipeline).

In view of above, a third 24" pipeline from CRP to OT is proposed to be installed.

#### 4.3.3 Third MEG Pipeline

The Initial Development Plan provided for two MEG pipelines from OT to the Umbilical Termination Assemblies (located near to DWPLEM). One 6" MEG pipeline was adequate to cater for the MEG injection required for water production corresponding to 40 MMSCMD. The other line was considered to avoid single point failure and provide adequate redundancies.

The FEED Update study brought out that when the discoveries already made are integrated with the Dhirubhai –1 and Dhirubhai - 3 facilities, both the pipelines will have to be necessarily used to meet the demands of MEG injection for water production corresponding to 80 MMSCMD. The analysis further brought out that even for 80 MMSCMD flowrate from Dhirubhai –1 and Dhirubhai - 3, one of the lines will not be adequate and both the pipelines will have to be used. Thus in either case, no redundancy will be available in the system. Therefore, it was recommended that a 3rd 6" line (together with the 3rd 24" production line from CRP to OT) be installed from OT to Umbilical Distribution Hub (located near to DWPLEM)

Accordingly, a third 6" MEG pipeline is proposed to be installed.

#### 4.3.4 Second DWPLEM and Twin 18" mid-water pipelines

The twin 24" mid-water pipelines considered in the Initial Development Plan will not be sufficient to transport 80 MMSCMD of gas from Dhirubhai –1 and Dhirubhai - 3 up to the CRP when the reservoir pressure depletes. However, other discoveries in KGD6 block may be integrated with the production facilities of Dhirubhai –1 and Dhirubhai - 3 at the CRP before additional mid-water pipelines are required. In this scenario, production from other discoveries will contribute to the total gas production and additional mid-water pipelines may not be needed for Dhirubhai –1 and Dhirubhai - 3.

But for the production profile with a plateau rate of 80 MMSCMD of gas from Dhirubhai –1 and Dhirubhai - 3 only, two additional 18" mid-water pipelines and a second DWPLEM have been considered for the purpose of cost estimation. The twin 18" mid-water pipelines may be laid from the second DWPLEM to the CRP. The second DWPLEM is proposed to have provision for tie-in of a total of 4 manifolds (including 2 spare).

### 4.3.5 Two Manifolds

The Initial Development Plan provided for 10 manifolds for a total of 34 wells. In view of the number of wells being increased from 34 to 50, two additional manifolds are proposed to be installed. At the commencement of production, it is envisaged that 22 wells will be connected to 7 manifolds. The remaining 5 manifolds can be installed later during the field life when more wells are drilled to maintain the plateau rate.

### 4.3.6 One SDA and Two SDU's

One SDA and two SDU's are proposed for the 2 additional manifolds and 16 additional wells. These are in addition to the 3 SDA's and 10 SDU's considered in the Initial Development Plan.

### 4.3.7 Upgradation of Onshore Terminal

The Onshore Terminal, as described in the Initial Development Plan, was for an initial gas handling capacity of 40 MMSCMD, with adequate space provisions to add additional modules in future to increase the plant handling capacity to 80 MMSCMD.

Under the revised conditions, where gas rate of 80 MMSCMD or more is proposed to be handled, the processing involved at the Onshore Terminal will essentially remain the same as described in the Initial Development Plan. However, the processing capacity of the Onshore Terminal is proposed to be upgraded to a gas flowrate of 80 MMSCMD with provisions to further enhance the capacity to 120 MMSCMD by adding modules at a later date.

Accordingly, modular units such as slug catchers, separators, dehydration trains, fiscal meters, utility equipment etc. will be designed for 80 MMSCMD gas handling capacity, while the common systems such as headers, flare, drains etc. will be sized for 120 MMSCMD flowrates.

For a handling capacity of 80 MMSCMD (expandable to 120 MMSCMD), it was considered beneficial to have each processing and dehydration train for 20 MMSCMD instead of the original proposal of 15 MMSCMD trains. Thus, a total of 4 trains, each of 20 MMSCMD capacity is proposed to be installed initially.

When the Initial Development Plan was submitted, delivery pressure ex-Onshore Terminal was assumed as 72 barg. However, the delivery pressure conditions have now been firmed up with the gas transportation agency and delivery pressure commitment of 97-98 barg has been indicated by the gas transportation agency. To meet this delivery pressure commitment, commensurate compression facilities need to be included at the OT. It is proposed to include 2 running and 1 standby trains to compress 80 MMSCMD of gas from 70 bar to 100 bar

No change in gas processing scheme is envisaged and will be upgraded from an initial design of 40 MMSCMD (upgradable to 60/80 MMSCMD) to 80 MMSCMD (upgradable to 120 MMSCMD). The major facilities at the OT will consist of the following:

- Slug Handling and separation
- Dehydration
- Metering and Custody Transfer System.
- MEG Regeneration
- Produced Water Treatment and Disposal
- Relief and Flare System.
- Closed Drain System
- Open Drain system
- Main Power Generators
- Emergency Power Generation
- Compressed Air and Nitrogen systems
- Diesel Fuel System
- Fire Water Systems
- Fuel Gas System
- Utility Water System
- Hot oil system
- Fire and Gas Detection System
- Onshore Compressor Facility
- Control Rooms, Laboratories, Workshops, Living Accommodation, Helipad & hanger and Storage spaces.

Following facilities have not been considered in the initial design. However, adequate space provision is proposed to be kept at the Onshore Terminal, in case these facilities are required at a future date:

- Rich Gas handling and processing
- Condensate stabilisation, storage and disposal facilities
- Hydrocarbon dewpoint depression facilities

#### 4.3.8 Upgradation of Future Shallow Water Compression Facility

Based on the production profile, it is envisaged that compression facility may be required earlier than considered in the Initial Development Plan. Compression may possibly be needed two years after start of production to meet the minimum pressure requirements (of 72 Kg/cm2) ex-OT. The timing of offshore compression requirement could get deferred, if the discoveries already made are put into production earlier than envisaged. Since these discoveries are likely to be integrated at the Control & Riser Platform and arrival pressures at the platform end could be higher, not all gas may require compression and some amount of gas (from these discoveries) could bypass the compressors for some period of time. In brief, there may be some scope of optimization of the timing and amount of offshore compression requirement, and is proposed to be taken up at a later date. As a conservative approach and based on the production profile, upgradation of offshore compression for 80 MMSCMD gas flowrate has been considered in this Addendum to the Initial Development Plan.

### 4.3.9 Vent System for Hydrate Remediation

One of the key technical challenges for deepwater development is prevention of hydrate formation in the subsea structures and pipelines. Continuous injection of Mono-ethylene Glycol (MEG) at the wellhead has been adopted as the primary hydrate mitigation strategy for KG-D6 field development. MEG injection is a proven technology and is being used / planned in many deepwater gas fields.

As such the risk of hydrate formation with continuous injection of MEG is low. However, should there be a hydrate formation, suitable arrangements / strategies need to be in place to remove the hydrate blockage. During FEED, hydrate remediation philosophy considered the use of an Intervention Vessel for depressurization and injection of MEG or MeOH. Accordingly, the Initial Development Plan was based on use of Intervention Vessel for hydrate remediation,.

However, a detailed feasibility study on application of an intervention vessel for hydrate remediation was not carried out. A study was initiated with M/s Paragon, which concluded that use of a deepwater intervention vessel for removing a hydrate plug in a subsea pipeline is not a viable option due to station keeping requirements of the vessel, large weight of equipment to be mobilized and requirement of the vessel to be classified for hydrocarbon handling.

This aspect was taken up under the FEED Update study and detailed flow assurance work was carried out to develop a suitable hydrate remediation scheme. The study concluded that a hydrate blockage could be removed by double-sided depressurization (both sides of the hydrate plug) of a blocked line through a separate pipeline system. The depressurization is proposed to be carried out from the Control & Riser Platform using a vent system consisting of the following elements:

- 2" conduit within the infield umbilicals from X-mas tree to manifold
- Vent header with valves in each of the manifolds
- 3" pipeline from each manifold to DWPLEM
- 4" pipeline from DWPLEM to CRP

## *4.4 Deletion of Methanol System*

Based on optimization of production facilities during FEED Update Study, it is proposed to delete the Methanol (MeOH) system considered in the Initial Development Plan for well shutdown and start-up. MEG is now proposed to be used for both continuous hydrate inhibition and during shutdown / start-up operations.

The key drivers for deletion MeOH system are the following:

- Transportation of methanol from OT to subsea wells required a 3" line at the centre the two main umbilicals. The resulting large diameter of the main umbilicals made their installation very challenging and limited the number vessels capable of laying these umbilicals. Two 3" methanol lines outside the main umbilicals were then considered but this resulted in increased installation time. Therefore, elimination of the methanol system will improve installability both in terms of ease and duration of offshore installation.

- MeOH is more hazardous than MEG due to higher vapour pressure, flammability and toxicity. Therefore, elimination of MeOH will improve the overall safety of the OT.

- Contamination of MEG with MeOH may cause problems in MEG regeneration system.

- MeOH can contaminate the sales gas.

- Recent deepwater developments, e.g. Ormen Lange and Snohvit developments, have been designed with provision to use MEG for both continuous hydrate inhibition and during shutdown / start-up operations.

Based on the above, the final schematic for the offshore and onshore facilities is shown in Fig. 4.1. The break-up of facilities proposed to be installed upto 2008-09 (for First Gas) and beyond 2008-09 is tabulated below :-

| | Approved Dev. Plan | Proposed as per Addendum | |
|---|---|---|---|
| | | Upto 2008-09 | Beyond 2008-09 |
| Total No. of Development Wells | 34 | 50 | |
| Phasing of Development Wells | 14 + 10 + 10 | 22 (18 + 4) | 9 + 9 + 10 |
| Subsea Manifolds | 10 | 6 | 6 |
| Deepwater PLEMs | 1 | 1 | 1 |
| Shallow Water PLEM | 1 | - | - |
| Control cum Riser Platform | - | 1 | - |
| Gas Evacuation pipelines from SWPLEM / CRP to Onshore Terminal | 2 x 24" | 3 x 24" | - |
| Gas Evacuation pipelines from DWPLEM to SWPLEM / CRP | 2 x 24" | 2 x 24" | 2 x 18" |
| Infield pipelines (from manifold to DWPLEM) | 10 x 14/16" | 6 x 16/18" | 6 x 16/18" |
| Well Flowlines | For 34 wells | For 22 wells | For 28 wells |
| Processing Trains & Capacity (MMSCMD) | 3 X 15 | 4 X 20 (with provision to add another two trains) | - |
| MEG Lines | 2 x 6" | 3 x 6" | - |
| Future Shallow water Compression Platform Capacity (MMSCMD) | 40 | - | 80 |
| Onshore Compression (72 barg to 98 barg) | - | 1 | - |

### 4.5 *Additional Infrastructure Works for KG-D6 development*

The availability of infrastructure facilities like water, power, roads, port facilities, communication etc. plays a vital role in successful and timely completion of any major project like D6 Development. To support the major construction activities for considerable period of time which huge amount of material and manpower movement. The infrastructure available in Kakinada and near onshore terminal location at Gadimoga is considered inadequate and needs augmenting for achieving first Gas in June'2008. The following infrastructure is proposed to be developed to help in timely execution of this project :

#### 4.5.1 Construction Jetty near Land Fall Point (LFP)

Kakinada Deep Water Port currently has only three (3) berths catering to varied cargo and also providing support for the offshore drilling operations. Due to increase in traffic, there is a serious congestion in the port and availability of berth is becoming increasingly difficult. The field development involves import of huge amount of project cargo for both onshore terminal and offshore facilities. An exclusive dependence on Kakinada port for movement of project cargo would pose serious schedule risk due to potential delays on account of non-availability of timely berthing. It is considered necessary to have a back-up facility for movement of project cargo closer to the onshore terminal. It is, therefore, proposed to develop a construction jetty near LFP about 5 km away from the onshore terminal. This jetty would also be very helpful in providing logistics support to the large fleet of offshore construction spread which will be operating during the short weather window for the offshore construction. This was already included in the original Development Plan approved by GOI / MC.

#### 4.5.2 Service Road along the Pipeline Corridor

It is proposed to develop a 7 m wide service road along the pipeline corridor from LFP to onshore terminal for providing inspection and maintenance access to the multiple pipelines and umbilicals being installed in this corridor. Due to objection form local villagers, Pondicherry government has advised us to change the routing of this 5 km onshore pipeline moving it towards the river requiring regular inspections after every major event like floods and cyclones. This service road would also facilitate easier movement of project cargo from construction jetty to onshore terminal avoiding narrow public roads.

#### 4.5.3 Widening of MDR 1328 from Tallarevu to Onshore Terminal

10 KM stretch of road from Tallarevu (Off NH 214) to onshore terminal is narrow and can cater for only a single lane traffic. This is totally inadequate to handle the increased traffic and movement of cargo from Kakinada port to site. This road needs to be widened for 2 lane traffic and strengthened for movement of heavy cargo. State Government has advised that they are not in a position to take-up this work and advised to RIL to take-up this work. Considering criticality of this for timely completion

of D6 Development and to meet the first Gas date, it is proposed to take-up widening of this road.

### 4.5.4 Site Offices and Guesthouse

It is proposed to develop the infrastructure like site offices, warehouses, fabrication shops, guesthouse accommodation near onshore terminal site to expedite the project execution. Other infrastructure like communication facilities and connectivity would also be provided for the above facilities.

### 4.5.5 Additional office space at Kakinada

Additional office space is being developed at Kakinada to cater for the requirements during project execution including large number of vendor representatives, PMC personnel and RIL project execution team.

## *4.6 Offshore Vessel Support Base (OVSB) at Kakinada*

The development and production activities coupled with exploration operations in KG D6 block would increase the scale of operations multifold over the coming years. As a result of the increase in development and production activities in KG D6 block there is a significant increase in the demand for port related infrastructure and back up services. Other petroleum companies are also focusing on exploration efforts in KG basin and supporting their drilling operations from Kakinada Deep Water Port leading to a significant increase in demand for berthing space and associated port services. There has also been a steady increase in commercial cargo volumes being handled at the port leading to higher berth occupancies, which is creating pressure on berth availability, which has the potential of affecting the development and production plans.

Taking into account the increase of exploratory / development activities in the forthcoming years and long term requirements, only a captive Offshore Vessel Support Base (OVSB) with adequate infrastructure and support facilities will meet the logistics requirements. Therefore, it is proposed to set up a captive OVSB comprising a berth and associated infrastructure at Kakinada for providing berthing facilities and associated services to offshore vessels. The proposed captive OVSB will ensure guaranteed berth availability to support offshore activities resulting in savings on standby / demurrage.

## *4.7 Intervention Vessels*

In the Initial Development Plan, hiring of an intervention vessel as a long-term charter to support operations and maintenance was envisaged. However, in light of increased production from the field, increased number of subsea equipment, increased complexities and more particularly considering the future growth potential within the block, it is considered prudent and beneficial to own an intervention vessel instead of hiring a vessel for long term. Preparatory works such as assessing the requirements, developing vessel specifications, establishing contacts with designers/fabricators have been initiated. It is envisaged that a new-build vessel will be available by June, 2008; however in case of delay, an appropriate intervention vessel will be hired for a short period of time till the new-built vessel is available.

### *4.8 Air Logistics*

In view of extensive development and production activities envisaged for KG D6 block and also considering the future growth potential of this block, it is considered prudent to have a dedicated helicopter coverage to support operation and maintenance requirements. This helicopter will have underslung load carrying medivac and search & rescue systems to provide rapid operational and safety support for such a mega development.

It is considered that rather than charter hiring, owning of the helicopter and hiring services for its operation and maintenance is more cost effective and accordingly the same is recommended.

# SECTION – 5

# CAPITAL COST ESTIMATES

*5.1 General*

The capital cost estimate for the development of Dhirubhai 1 and Dhirubhai 3 gas fields to achieve gas sales volumes of 80 MMSCMD works out to US$ 5196.58 MM (For details refer Section 5.2). The Capex for the wells and facilities required subsequently and Opex shall be proposed in the annual Work Programme and Budgets.

It needs to be noted that the increase in Capex from that approved in the original development plan is on account of the current market prices (current price forecasts are based on July 2006 prices as against the initial development plan prices of 2003) as well as additional development wells and facilities being proposed both for offshore and onshore to achieve production of 80 MMSCMD, upgradable to 120 MMSCMD.

- Well cost – The well costs have been worked out based on our experience of drilling both exploratory and development wells in the blocks. The costs are based on the current rig and other services costs for drilling and well completion.
- The basis for capital cost facilities are based on the cost estimates provided by M/s. Aker Kvaerner subsequent to the Front End Engineering and Design work, as modified on account of discussions with vendors as well as awarded contracts.
- Project Management Cost is estimated at 6.25% of the capital cost. This includes the cost of the project management consultant as well as specialized personnel, specially required for subsea project.
- Onshore Terminal cost estimates do not include cost of land which is on lease basis. It includes cost of site grading and other infrastructure facilities such as helipad, buildings, laboratories, warehouses, temporary construction jetty, haul road, etc. for connecting the jetty to the Onshore Terminal.
- Engineering costs have been considered between 1.5 to 2% of the facility capital cost estimates.
- Certification and Verification costs have been estimated in the range of 1.0 to 1.5% of the capital cost estimates.
- Onshore Terminal Cost estimate is for 80 MMSCMD production level and do not include future cost pertaining to condensate stabilization, storage and disposal and Hydrocarbon Dew Point Depressant units.
- Eco-protection includes cost towards green belt development and protection and maintenance of offshore & local environment.
- Costs do not include charges, fees, taxes & duties arising out of statutory requirements and conditions stipulated in various permissions / approvals.

- On account of custom duty exemption being available, no custom duty has been considered in the costs above.
- All other taxes & duties have been considered based on current interpretation of applicability.
- Notwithstanding anything stated above, any costs not specifically mentioned above are to be construed as not included.

## 5.2 Estimated Capital Cost

The Capex estimates for initial development of Dhirubhai-1 & Dhirubhai-3 gas fields to meet gas sales volumes of 80 MMSCMD are as given below :

| [Figures in US$ MM] | | | |
|---|---|---|---|
| 1. | | G & G Studies | 34.67 |
| 2. | | Reservoir and Completion Studies | 22.66 |
| 3. | | Development Wells | 1164.58 |
| | | Drilling and Completion | 925.10 |
| | | Drill Preparation / Mob / Demob | 116.83 |
| | | Intelligent Completion | 54.00 |
| | | Distributed Temperature Sensing | 24.58 |
| | | Coring | 44.08 |
| 4. | | Production Facilities | |
| | (a) | Surveys and Environmental Clearance | 13.82 |
| | | Pipeline Route Survey / ROU and Maps | 0.97 |
| | | Geo-technical Investigations | 12.15 |
| | | Environmental Clearances | 0.70 |
| | (b) | Manifolds | 70.81 |
| | (c) | Pipelines & PLEMs (Excluding infield 16/18" & 8/10" pipelines) | 906.92 |
| | | 24" Export Pipelines | 677.71 |
| | | 18" Lines from DWPLEM2 to CRP | |
| | | MEG Pipelines | 132.48 |
| | | Effluent Line | 69.97 |
| | | Deepwater PLEM | 26.76 |
| | | Shallow Water PLEM | |
| | (d) | Subsea Control System & Umbilicals | 722.86 |
| | | Main Umbilical | 252.18 |
| | | Infield Umbilicals | 137.01 |
| | | SDAs and SDUs | 52.91 |
| | | X-mas Tree Controls & Instruments | 145.11 |
| | | Onshore Terminal Equipments | 4.34 |
| | | Jumpers & Toolings etc. | 131.32 |
| | (e) | Deepwater Pipeline | 323.82 |
| | | 16/18" Lines | 132.08 |
| | | 8/10" Lines & Jumpers | 191.74 |
| | (f) | Onshore Terminal Including Site Grading | 550.87 |
| | (g) | Compression | |
| | | Shallow Water Compression Platform | |
| | | Offshore Booster Compressor | |
| | (h) | Control cum Riser Platform (CRP) | 446.83 |
| | (i) | Vent System | 12.85 |
| | (j) | Vessel Mob-Demob | 366.89 |
| | (k) | Engineering Cost | 59.53 |
| | (l) | CVA Cost | 47.63 |
| | (m) | Project Management Cost | 212.62 |
| | | Sub-total –Production Facilities ((a) to (m)) | 3735.44 |
| 5. | | Eco-Protection (Community Development) | 4.30 |
| 6. | | General & Administration | 20.50 |
| 7. | | Abandonment | |
| 8. | | Information Technology | 9.46 |
| 9. | | Kakinada Captive Berth | 54.96 |
| 10. | | Owned Support, Intervention Vessel and Helicopter | 150.00 |
| | | Total – (1 to 10) | 5196.58 |

# SECTION – 6

# GAS UTILISATION PROSPECTS

### *6.1 Introduction*

Adequate supplies of natural gas are a key for the nation's sustainable development and gas is the fuel for the 21st Century. Natural Gas as a fuel is environmentally friendly, offers the potential of reducing working capital requirements and being lighter than air strengthens the safety aspects at the end user facilities. An underserved natural gas market can hamper sustainable economic development and the attendant multiplier benefits.

Indian gas market is currently highly supply constrained. It is for this reason that bulk of the available gas is utilized in Fertilizer and Power sectors, considered to be the core sectors. Though there is significant merit in use of Natural Gas for industrial, commercial, domestic sectors as well as in transport sector on environmental considerations, these sectors have remained underserved due to gas supply constraints. These gas market segments, considering the size of the cities in India, population density, growing urbanization, greater emphasis on cluster and multi-storied housing complexes, ever growing vehicle population and expanding small industrial and commercial establishments within the cities, as well as at its peripheries, are expected to aggregate in to considerable gas demand over the years and may emerge as large demand centres for Natural Gas in the coming decades.

These sectors normally provide larger utilisation potential but due to supply constraints and priority to Fertilizer and Power sectors for gas allocation, potential of gas utilization in city distribution gas projects has remained untapped. However, with the increased gas availability from a number of discoveries made/expected from blocks awarded under NELP and through a number of gas import projects under implementation/consideration, the use of gas in the country will grow to become the fuel of the 21st Century.

### *6.2 The Indian Market*

The share of Natural Gas share in India's energy basket is currently 8% against the global average of 24% and about 40-45% in some of the developed countries. However the low share of Natural Gas is largely driven by limited domestic availability and the absence of a well-developed pipeline infrastructure. Therefore, once gas becomes available, contribution of natural gas in the energy sector in India, would grow substantially. The share of natural gas in the energy market in India as per Hydrocarbon Vision 2025 is projected to increase with the availability of gas in the country from domestic sources as well as through imports to the level of 24-25% by 2025.

Demand Outlook

Several agencies, both national as well as international have estimated future gas demand in India. Although the results of various studies vary from each other, all of them indicate huge demand potential in the country. The results of some of the studies are summarized in Table shown below :

Summary of gas demand from various agencies:

| Year | Projections by Various Agencies | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | EIA (2004) | | | IEA (2004) | IHV (2025) (2000) | India Vision (2020) (2002) | | Power & Energy Division's projections (2003-04) | IRADe & PWC * | |
| | Reference Case | High Case | Low Case | | | BAU | BCS | | BAU | HOG |
| Base Year | 2001 (62 MMSCMD) | 2001 (62 MMSCMD) | 2001 (62 MMSCMD) | 2000 (67 MMSCMD) | 1999 – 2000 (110 MMSCMD) | 1997 (59 MMSCMD) | | 2001-02 (81 MMSCMD) | 2003-04 (85 MMSCMD) | |
| 2004-05 | 74 | 77 | 74 | 91 | 195 | 89 | 87 | 98 | 93 | 95 |
| 2009-10 | 93 | 101 | 93 | 140 | 277 | 115 | 111 | 134 | 145 | 164 |
| 2014-15 | 124 | 132 | 109 | 189 | 329 | 149 | 142 | 183 | 226 | 285 |
| 2019-20 | 155 | 171 | 132 | 228 | 358 | 194 | 177 | 249 | 356 | 493 |
| 2024-25 | 195 | 225 | 155 | 259 | 391 | 258 | 226 | 326 | 488 | 738 |
| 2029-30 | | | | 295 | | | | 430 | 667 | 1111 |

EIA – Energy Information Administration, USA

IEA – International Energy Agency

IHV – India Hydrocarbon Vision 2025

IRADe – Integrated Research and Action for Development

BAU – Business as Usual

BCS – Best Case Scenario

PWC – Price Waterhouse Coopers

HOG – High Output Growth

* Includes Natural Gas and NG equivalent of Naphtha

**Note: As the available projections by the various agencies are for different years, the same have been intrapolated or extrapolated to bring them to common years and have been converted into MMSCMD for the purpose of comparison.**

**Source: Integrated Energy Policy (Planning Commission)**

### 6.2.1 India's Energy demand

Over the past five years India's GDP has grown at the rate of 6% per annum on an average. In the same period the rate of growth in commercial energy has been at 4.35% per annum. India is currently on an aggressive growth path and energy security would play a crucial role in achieving the GDP growth targets. India is currently on an aggressive growth path and energy security would play a crucial role in achieving the GDP growth targets. The Planning

Commission estimates in its document on the Integrated Energy Policy of India that the elasticity[1] for per capita primary consumption with respect to per capita GDP is 0.82. In the future as the energy elasticity of GDP growth will not fall as rising income levels will foster life style changes that are more energy intense.

The Integrated Energy Policy (Report of the Expert Committee) by Planning Commission, August 2006, has projected GDP growth rate and corresponding energy requirement as follows :

| Year | Population in Millions | GDP in Rs Billion | Commercial Energy in MTOE | Non Commercial Energy in MTOE | Total Energy Consumption in MTOE |
|---|---|---|---|---|---|
| 2006-07 | 1114 | 18,171 | 397 | 153 | 528 |
| 2011-12 | 1197 | 27,958 | 551 | 169 | 652 |
| 2016-17 | 1275 | 43,017 | 748 | 177 | 802 |
| 2021-22 | 1347 | 66,187 | 1015 | 181 | 979 |
| 2026-27 | 1411 | 101,837 | 1360 | 183 | 1235 |
| 2031-32 | 1468 | 156,689 | 1823 | 185 | 1529 |
| CAGR | 1.1% | 9.0% | 6.3% | 0.8% | 4.3% |

As can be observed from the above table:

- Energy demand is largely driven by GDP and an increase in population
- India's population is expected to increase from 1.1 Billion in 2006-07 to nearly 1.47 Billion by 2032 an increase of 1% per annum.
- In the same period, India's GDP is expected to increase from Rs 18,171 Billion to nearly Rs 1,56,689 Billion an increase of 9% per annum.
- Consequently, India's total energy demand is slated to rise from 397 MTOE in 2005 to nearly 1,823 MTOE an increase of 6% per annum

The Committee has projected that in the commercial energy space the requirement from various sources would be as follows:

| Year | Hydro MTOE | Nuclear MTOE | Coal MTOE | Oil MTOE | Gas MTOE | Total Energy Consumption in MTOE |
|---|---|---|---|---|---|---|
| 2006-07 | 9 | 7 | 200 | 124 | 35 | 375 |
| 2011-12 | 15 | 15 | 253 | 151 | 49 | 483 |
| 2016-17 | 19 | 29 | 322 | 188 | 67 | 625 |
| 2021-22 | 24 | 54 | 393 | 234 | 92 | 797 |
| 2026-27 | 34 | 79 | 517 | 294 | 127 | 1051 |
| 2031-32 | 43 | 115 | 641 | 370 | 175 | 1344 |
| Growth Rates | 7% | 12% | 4.9% | 4.1% | 7% | 5.2% |

In addition, the following has been observed in the Integrated Energy Policy developed by the Committee:

[1] Percentage change in commercial energy requirement for one per cent change in GDP

- India's dependence on fossil fuels is likely to remain high over the forecast period. It would increase from 68% of the total energy mix to touch 78% of the total energy basket by 2032.
- India 's oil demand is expected to treble from 124 MTOE in 2006-07 to nearly 370 MTOE by 2032 an increase of 4% per annum. Oil demand is largely driven by end use applications in the transport sector and usage of liquid fuels in industries
- It is estimated that 47%[1] (53 Million Tons) of India's needs are primarily from the transportation sector while 53% (59 Million tons) caters to the industrial and the household sectors.
- India's gas demand is expected to increase five fold from 35 MTOE to nearly 175 MTOE by 2032 an increase of 7% per annum
- India's coal demand is expected to treble from 200 MTOE to nearly 641 MTOE by 2032 an increase of 5% per annum

### 6.2.2 Energy Security

Based on the above projections, oil and gas would continue to be an important source of energy for the country, contributing more than 40% of the total energy requirement by 2032. The oil and gas requirement by 2032 would be 370 mmtoe and 175 mmtoe respectively as against the current production of around 33 mmtoe and 25 mmtoe respectively.

In 2005-06, India imported 99.4[3] Million Tons of crude oil at value of US$ 39 billion. The average crude price for the Indian basket is estimated at $ 392 per MT or $ 52.62[2] /bbl for the year 2005-06. India also imports 5 Million tons of LNG at Dahej through long term contracts from Qatar at an import bill of US$ 700 million.

India's import dependency is likely to increase and oil would account for a significant portion of India's energy imports in the coming years. It is estimated by the Planning Commission that India's import dependence could touch 91%-93% by 2031/32

Thus, to ensure energy security in the country stress has to be laid on domestic production of oil and gas.

### *6.3 Supply Potential from Developed / Developing / New Reserves*

The proposed development of the Block set out in this Development Plan assumes that RIL to market all of the gas production from Block KG-D6 on behalf of GOI and NIKO. Marketing of gas is critically dependent on the volumes of gas available for commitment under the gas sales contracts that must be negotiated with potential consumers.

Regarding the availability of gas, Ministry of Petroleum & Natural Gas had formed a Sub-Group for assessing the availability of natural gas from various sources. While the Subgroup has yet to finalise its report but the draft report shows that availability of gas from domestic sources after considering 40 MMSCMD of gas from Dhirubhai Gas Fields (based on Initial Development Plan filed by Reliance) on the eastern coast may peak at

[1] ATF, HSD and MS

130 MMSCMD by 2006-07 and may go down to 103 MMSCMD by 2010-11 due to reduction in the availability of gas from ONGC sources. No new resource other than Dhirubhai Gas Field has been considered by the Sub-Group. Availability of gas from ONGC, which is currently at the level of 66 MMSCMD, is projected to come down to 35 MMSCMD by year 2010-11.

### *6.4 Utilization of Gas from Dhirubhai Gas Fields*

The gas from Dhirubhai Gas Fields is expected to be utilized in the States of Andhra Pradesh, Maharashtra, Karnataka, Gujarat and states along the HBJ pipeline. The state-wise gas utilization and deficit projection are deliberated as below :

**(i) Andhra Pradesh:**

| | |
|---|---|
| Current Allocation of gas | 8.70 MMSCMD |
| Current Availability of gas (2006-07) | 7.00 MMSCMD |
| Deficit | 1.70 MMSCMD |
| *Additional Allocations | 7.15 MMSCMD |
| [GVK-1.1,Konaseema-2.1,Vemagiri-1.75,Gautami-2.1, APIIC-0.1] | |
| AP Genco (Karimnagar) | 8.00 MMSCD |
| Total Demand | 16.85 MMSCMD |

Besides the above, there is significant potential for utilizing gas along the pipeline route as a replacement of liquid fuel in industrial, commercial and residential sector. It is estimated that about 20.00 MMSCMD of gas could be used in the State. Gas from Dhirubhai Gas Fields would enable meeting the above deficit as no other source of supply of gas is currently foreseen in this region. In addition to the above, gas demand through replacement of liquid fuel in industrial, commercial and residential sectors in urban and semi urban areas is also expected to be large.

**(ii) Maharashtra:**

The current gap between allocation and projected availability of gas is of the order of 7.5 MMSCMD in the Uran region. In addition there is demand gas from consumers for their expansion projects as detailed below:

| Uran Demand/ Projected availability analysis | |
|---|---|
| Current Allocation of gas | 15.80 MMSCMD |
| Current Availability of gas (2006-07) | 7.50 MMSCMD |
| Deficit | 8.30 MMSCMD |
| *Additional Demand of expansion at Uran | 11.80 MMSCMD |
| [RCF-4.5, TPC-4.8, Vikram-1.0, DFPCL-0.5, NDIL-1.0] | |
| Ratnagiri Power | 8.0 MMSCMD |
| RIL (Captive) | 5.0 MMSCD |
| Total Deficit | 25.10 MMSCMD |

The projected shortfall in supply to existing consumers and expansion projects is of the order of 25.00 MMSCMD. In the absence of any supply being augmented in the Western region to meet this deficit, gas from Dhirubhai gas field is expected to bridge this gap. In addition to the above, gas demand through replacement of liquid fuel in industrial, commercial and residential sectors in urban and semi urban areas is expected.

**(iii) Gujarat- Hazira region:**

Gujarat is one of the biggest gas market in the country today. In spite of augmentation of supply in this region through commissioning of two LNG terminals, there is still shortfall in gas supply. In addition, new gas based facilities are also planned in the state. The expected incremental demand in the state is projected is as follows:

| | |
|---|---|
| NTPC projected demand (including expansion) | 17.00 MMSCMD |
| Other Demand in Gujarat | 9.00 MMSCMD |
| [KRIBHCO-3.0, IOC -1.0, GPEC-3.0, GSFC/GNFC- 2.0] | |
| RIL Jamnagar | 14.00 MMSCD |
| RIL Hazira | 2.50 MMSCMD |
| IPCL | 2.50 MMSCD |
| Total Demand | 45.00 MMSCMD |

In addition to the above, gas demand through replacement of liquid fuel in industrial, commercial and residential sectors in urban and semi urban areas is expected.

**(iv) Karnataka:**

Karnataka Power Corporation Limited (KPCL) is planning 1400 MW power plant to be located at Bidadi, near Bangalore.

| | |
|---|---|
| KPCL Bidadi | 8.00 MMSCMD |

In addition to the above, gas demand through replacement of liquid fuel in industrial, commercial and residential sector is also expected.

**(v) Uttar Pradesh:**

Reliance Energy Limited, has proposed to set-up around 7200 MW gas based combined cycle project at Dadri, near Delhi. In first phase capacity of 3740 MW is expected to be commissioned. It is expected that 18.00 MMSCMD of natural gas will be required for the plant including utilities.

| | |
|---|---|
| Reliance Energy Ltd. | 18.00 MMSCMD |

(vi) Demand along the HVJ pipeline:

Due to constrained availability of natural gas, there is considerable gas supply deficit along the HVJ inter-state pipeline owned and operated by GAIL. The estimated deficit along the HVJ is around 10 mmscmd. This can also be catered to by gas from Dhirubhai gas fields.

Thus utilization of gas from Dhirubhai Gas Field would emerge as under:

| | |
|---|---|
| Andhra Pradesh | 20.00 MMSCMD |
| Maharashtra-Uran | 25.00 MMSCMD |
| Gujarat- Ex Hazira | 45.00 MMSCMD |
| Karnataka – Bidadi | 8.00 MMSCMD |
| Uttar Pradesh – Dadri | 18.00 MMSCMD |
| Along HVJ pipeline | 10.00 MMSCMD |
| Total | 126.00 MMSCMD |

(vi) Demand from City distribution

Globally in developed countries, natural gas finds usage in space heating, air conditioning and in combined heat and power applications. Combined Heat and Power applications have higher efficiency levels than the traditional gas fired open/combined cycle applications. As income levels rise and lifestyle needs change, there is a demand for fuels which can offer uninterrupted power with low levels of Green House Gas (GHG) emissions.

In this context, it needs to be highlighted that in India, the growing levels of urbanization are likely to increase the energy consumption intensity. The urban clusters inter-alia would include offices, commercial establishments, housing complexes and ITES services. These consumers require convenience of usage, uninterrupted energy supplies for various applications in air-conditioning and heating.

Currently the city gas distribution networks in India largely cater to the needs of the transportation sector and for heating applications in households, commercial and industrial establishments.

However in the future spurred by increased availability, Natural Gas would find applications in the emerging market segments of air conditioning, heating and decentralized generation and distribution of power.

It is reasonable to assume 20% additional utilization by industrial/commercial/automotive sector along the pipeline route to the above mentioned consumers amounting to around 25 MMSCMD giving a total potential for utilization of 150 MMSCMD of gas.

Thus 80 MMSCMD from Dhirubhai gas field would help significantly help in meeting the gas requirement in the country.

## *6.5 Availability of gas from Dhirubhai Gas Field*

The Dhirubhai gas field on the eastern coast is the largest discovery in the world during the year 2002 and would contribute significantly towards enhancing the energy security of the country. The discovery also will help in bridging the gap between demand and availability of gas, which was otherwise to be met through importation of gas through pipelines from Iran, Bangladesh and Myanmar or in the form of LNG.

80 mmscmd gas supply from Dhirubhai gas fields would help in meeting the following objectives:

- **Reduction in external transfers:** India's oil import bill of US$39 billion can be reduced by substituting end use applications of oil by natural gas. The potential liquid fuels that could be replaced are Naphtha, LSHS/LDO, HSD and Fuel Oil. A large portion of this additional 80 MMSCMD of domestic gas would go is replacement of these liquid fuels as they are being consumed due to short-fall or non-availability of gas. Currently India consumers around 25 mmtpa of industrial liquid fuels (Naphtha/ Fuel Oil/ LSHS/ Industrial HSD) growing at the rate of 3-4% per annum. Even if 75% of this is replaced by natural gas (80 mmscmd is equivalent to around 25 mmtoe per annum), it would result in reduction of import bill by about $ 8 billion per annum.
- **Better utilization of existing facilities:** Large portion of natural gas from Dhirubhai gas fields would be consumed by existing facilities which are facing shortfall in gas supplies and are therefore not running to there full capacity potential. This additional gas can make India's industrial capital more productive by increasing the utilization rates of existing assets which may have been lying idle.
- **Value proposition for the economy:** India's Natural gas which offers cheaper alternative to oil resulting in reduction of energy bill. Currently oil prices are around $60/bbl, equivalent to $ 10/mmbtu in energy equivalent terms. Oil futures markets indicate that crude oil prices would be at about $69/bbl in 2011. Domestically sourced natural gas has the potential to replace liquid fuels and lower India's crude oil import requirements as it is more energy efficient.
- **Lower transportation tariffs for consumers:** Higher transportation volumes enable the gas transporter to amortize capital and operating costs over a larger volume. This would lower delivery costs to potential consumers.
- **Reduction in the fiscal burden on the government:** Natural gas finds applications in the domestic and the transport sectors. In the domestic sector natural gas may replace LPG and in the transportation sector it could replace MS/HSD. Currently the government of India incurs Rs 75000 crores in subsidies for the fuel sector. The under-recoveries by the Oil Marketing companies touched Rs 9274 crores in 2003-04 and Rs 20,146 crores in 2004-05. Replacement of these fuels by gas would result in subsidy savings for the Government.

- **Multiplier effect:** Gas availability from Dhirubhai gas fields would result in more than doubling of gas production in the country. This would lead to energy supply driven growth in the industrial activity in the country and would have a multiplier effect on the economy.
- **Environmental Benefits:** Liquid fuels have higher levels of carbon emissions than gas and have higher carrying costs due to storage and handling. The $CO_2$ emissions from gas are 20-30[2]% lower than most of the liquid fuels. Natural gas is also more efficient than other liquid fuels by 20-30%.

### *6.6 Gas Transportation Infrastructure*

To service potential gas consumers in the states of Andhra Pradesh, Karnataka, Maharashtra, Gujarat, Uttar Pradesh and consumers along the HVJ transmission/distribution system needs to be created. Reliance Gas Transportation Infrastructure Limited (RGTIL), is creating the required gas transmission and distribution network in the country. As a part of their overall plans, 48 inch 1400 km Kakinada-Hyderabad-Ahmedabad sector of the pipeline (East West Pipeline (EWPL)) is being constructed in the initial phase, Right of Use (ROU) has already been obtained. The construction of the proposed pipeline is expected to commence shortly. EWPL commissioning is planned to be synchronized with the development of Dhirubhai Gas Fields. Pipelines for gas transportation to Bangalore, Chennai, and Calcutta are also being planned matching with the gas requirements of the respective major gas consumers in these states.

### *6.7 Conclusion*

The current Indian gas market is supply constrained. An under-served market affects economic development and its attendant multiplier benefits. In the future India's GDP is projected to grow at 9%. A growing economy requires energy and the current energy elasticity in India is likely to remain high. Rising incomes and lifestyle needs would further increase energy demand.

Natural Gas from the D6 fields as fuel would put India on the path of sustainable development. The Planning Commission estimates that India's gas demand is expected to increase to nearly 534 MMSCMD by 2032.

In 2006-07 the potential demand in the states of AP, Karnataka, Maharashtra and Gujarat and along the HVJ pipeline is expected to touch 126 MMSCMD and has the potential to go up to 150 MMSCMD. This demand would arise from replacement of liquid fuels, better utilization of Industrial facilities and urban clusters in these states. It is expected that the gas availability from Dhirubhai Gas Fields will provide all the scope for its utilization.

The existing gas market in India is huge and provides sufficient scope for utilization of the gas available from Dhirubhai Gas Fields. There is potential in the States mentioned above for utilizing around 150 MMSCMD by identified consumers. Thus 80 MMSCMD of gas produced from Dhirubhai gas field can be effectively utilized in the Andhra Pradesh, Maharashtra, Gujarat and Karnataka, Uttar Pradesh and consumers along the HVJ pipeline.

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2 IPCC 1996 Guidelines

It is also expected that the required infrastructure of gas transportation and distribution shall be in-place matching with the gas availability from Dhirubhai Gas Field Development and the gas demand of the major gas consumers. Gas production at the rate of 80 MMSCMD would help in (i) substantial reduction in consumption of liquid fuels and the resulting oil import bill (ii) better utilization of existing gas based assets through higher gas availability (iii) availability of cheaper alternative to oil (iv) lower transportation tariff for consumers through economies of scale (v) saving in Government subsidy through replacement of LPG/ HSD/ MS (vi) increase in supply driven industrial activity (vii) considerable increase in energy security for the country.

# SECTION – 7

# PROJECT SCHEDULE

The schedule for project execution of the facilities for Dhirubhai-1 and Dhirubhai-3 gas field development is enclosed in Fig. 7.1 which envisages First Gas production by mid 2008.

## *7.1 Schedule Considerations*

### 7.1.1 Drilling & Well Completions

a) Drilling

- Total no. of wells :- 22 (18 +4)
- New Wells :- 16, Coring considered in four wells (in addition to already cored wells)
- Re-entry wells :- 6 (A1, A2, B1, B2, A10A & B7)
- One rig considered for drilling of 16 new wells.
- Start of drilling preponed to Oct/Nov-06 (As against Apr-07 considered as per the approved Development Plan).

b) Well Completions

- Total no. of well completions :- 22
- First batch of Xmas trees likely to be delivered at site in Nov 07.
- Well completions considered to start from Nov – 07 with one rig.
- Another rig considered for well completions starting from May-08 (Only one rig considered for well completions during major offshore installation window of Dec 07 – Apr 08).

### 7.1.2 Subsurface

Release of remaining 12 nos. of well locations considered in Nov/Dec-06.

### 7.1.3 Offshore Facilities

a) Initial Facilities :-

- Manifolds – 6 nos.
- DWPLEM – 1 no.
- Umbilical Distribution Hub (UDH) – 1 no.
- Control cum Riser Platform (CRP) in shallow waters – 1 no.
- 6"/8" flowlines from wells to manifolds
- 6 x 16" / 18" pipeline from Manifolds to DWPLEM
- 2 x 24" midwater pipeline from DWPLEM to CRP
- 3 X 24" gas trunkline from CRP to OT
- 3 x 6" MEG lines from OT to UDH
- 1 X 12" Effluent pipeline
- 2 control / power cables from OT to CRP
- 2 main umbilicals from CRP to UDH
- Infield umbilicals from UDH to field

- 3" / 4" NB vent lines from wells to CRP

b) Ordering of long lead packages :-
   - Package 1 – Xmas Trees, Subsea Control System & Umbilicals
   - Package 2 – Subsea structures incl. Manifolds, DWPLEM, & Tie-in system
   - Package 3 – Linepipes

   All the above packages have been ordered and expect deliveries at site by Nov / Dec 07 prior to start of offshore installation works.

c) EPIC / Offshore Installation :-
   It was essential to commit at the earliest the specialized deepwater construction vessels for major offshore installations during 2007-08 since a large number of deepwater development projects are competing for these spreads during that season. Installation contract has been awarded.

   Following is the scope of work of EPIC / Offshore installation contractor.
   - Participation in System Integration Test (SIT) proposed to be carried out during Aug-Oct 07.
   - Transportation of Package 1, 2 and 3 materials.
   - Coating of linepipes
   - Installation of offshore facilities as explained above (3.a) incl. pipeline(s) installation from OT to Land Fall Point (LFP)
   - Major offshore installation considered during Dec-07 to Apr-08 as the offshore construction weather window on the east coast is limited to 4-5 months in a year from Dec to Apr.

d) CRP – Control and Riser Platform -
   Detail design, fabrication, load-out, transportation & installation. CRP installation contract has been awarded. Jacket installation targeted in Sept/ Oct – 07, Deck installation in Dec–07/Jan–08 and hook up and commissioning in Jan/Apr-08.

e) OT to LFP pipeline installation – (about 5 km) is planned to be awarded and construction schedule to match overall Project schedule.

f) Rock dumping in river section – Rock dump/cover provides protection against scouring. Contract for sourcing and transporting is being worked upon.

### 7.1.4 Onshore Facilities

- FEED Update and Detail Engineering for Onshore Terminal (OT) – Work awarded separately.
- Major long lead packages; viz. MEG Regeneration / reclamation, On Shore Gas Compressor, Gas Dehydration and TEG regeneration & Slug catchers identified and is ordered directly by RIL in order to meet the target First Gas by mid 2008.
- Turbine Generators (TG) is another long lead package, which is planned to be ordered shortly.
- A separate Procurement and construction contract is considered.
- Site preparation activities including Dredging for extraction of fill material & site related works are being handled directly by RIL.
- Space provisions are being made at Onshore Terminal for handling gas volumes higher than 80 MMSCMD.

- Site infrastructure facilities are being developed.