Executive Summary

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1. Introduction

In 1991, the Government of India (GoI) decided to invite foreign and domestic Private Sector Companies to participate in the development of discovered oil and gas fields, and in some cases, fields partially developed by the National Oil Companies (NOCs) – Oil and Natural Gas Corporation Limited (ONGC) and Oil India Limited (OIL). The GoI announced (1997) the New Exploration Licensing Policy (NELP), under which NOCs compete with Private Sector Companies for obtaining Exploration & Production (E&P) licenses through a bidding process, instead of getting them on nomination basis.

The Ministry of Petroleum and Natural Gas (MoPNG), the Directorate General of Hydrocarbons (DGH) and the Contractor /Operator of the blocks are the main stakeholders in the PSC. The MoPNG is, *inter alia,* responsible for the exploration and production of petroleum and natural gas, including the administration of the Oilfields (Regulation and Development) Act, 1948. MoPNG is assisted by the DGH, which was established in April 1993 with the objective of promoting sound management of Indian petroleum and natural gas resources having a balanced regard for the environment, safety, technological and economic aspects of petroleum activities. The Contractor is required to carry out petroleum operations and has the right to recover cost and expenses in case of a successful commercial discovery leading to production, as per terms of the PSC.

The PSCs between the GoI and the Contractor(s) for specific fields / blocks provide the contractual basis for petroleum operations, cost recovery, profit sharing and other aspects.

The content of these PSCs varies substantially among those for discovered fields, pre-NELP exploratory blocks and NELP blocks, and even within different NELP rounds (with Model PSCs being drawn up for each NELP round).

2. Main Audit Findings and Recommendations

2.1 KG-DWN-98/3 (Operator: RIL)

The KG-DWN-98/3 (also referred to as KG-D6) block, with a contract area of 7645 square km (sq. km.), is an offshore block in the KG basin. The Block is classified as a "deepwater block", with water depth ranging from 400 metres (m) in the north-west to 2700 m in the south-east. The total expenditure incurred in the block till March 2013 was US$ 10,441.98 million out of which US $ 9,293.22 million had been cost recovered by the Contractor. Out of the Profit Petroleum (PP) of US$ 1032.58 million till March 2013, the Contractor has got US$ 929.32 million and the GoI has got US $ 103.26 million.

Regulatory and control issues

- In none of the four years' audit period was the annual Work Programme and Budget (WP&B) approved before start of the FY. The WP&B is one of the most important tools available with the MC to exercise monitoring and control over the operations of the block. Since MC did not effectively utilize this tool, there was inadequate budgetary / financial control over operational activities leaving the expenditure open-ended.

(Para 2.4.1)

Audit recommends that MoPNG / DGH may take action for timely approval of the WP&B in future.

- Expenditure amounting to US$ 160.81 million incurred on account of three appraisal wells was not eligible for cost recovery and had been disallowed by MoPNG. However, even after the MoPNG communicated its decision, the Operator continued to claim the cost recovery, as seen in the final accounts for the year ended 2013. As of June 2014, the MoPNG had been unable to enforce its decision.

(Para 2.4.2)

Audit recommends that MoPNG may ensure that the disallowed cost of three wells amounting to US$ 160.81 million is recovered.

Approvals for petroleum operations

- MoPNG did not review determination of the entire contract area as 'discovery area' strictly in terms of Articles 4.1 and 4.2 at the end of the 1st and 2nd exploration phases before issuing relinquishment order under Article 3.11 in October 2013.
- MoPNG / DGH did not insist that the Contractor carry out only appraisal activities in the 'discovery area' till July 2009. Audit is of the opinion that further exploration activities in the 'discovery area' (which included drilling of eight exploration wells and six appraisal wells of discoveries resulting from these exploration wells at an expenditure of US$ 427.03 million) was improperly carried out at the risk of revenue of the commercial discoveries made in the block.

(Para 2.5.1)

Normally the entire amount of US$ 427.03 million would require to be disallowed for cost recovery since these activities were not in line with PSC provisions. However, from a pragmatic point of view, it has to be kept in mind that the exploration has resulted in a commercial discovery viz. D34 for which a development plan has already been approved. In three other cases viz. D29, D30 and D31 discoveries, review of commerciality is under finalisation. At this stage, keeping in mind the national interest and energy security, Audit recommends that MoPNG should accept sharing of exploration cost of only those of the above mentioned wells which resulted in a commercial discovery and disallow the cost recovery of US$ 118.99 million already effected by the Operator on the remaining wells. As regards the well cost in respect of D29, D30 and D31 discoveries, since the matter regarding the DoC is under consideration in MoPNG, the same may also be considered for disallowance in case they are not found to be commercially viable subsequently.

- As per PSC provisions, the review of DoC in respect of three discoveries, *viz.* D 29, D 30 and D 31, was to be completed by MC by August 2010. However, due to lack of adequate production testing data, DGH rejected the DoC proposal. Nonetheless, despite technical advice of the DGH to the contrary, the issue has been reopened after almost three years from the date when it was rejected by DGH and has not been finalised as yet.

(Para 2.5.2)

Audit recommends that MoPNG may develop consistent and uniform parameters for evaluating commerciality of discoveries.

- The degree of uncertainty and substantial changes in the recoverable gas reserves estimates raises questions on the process of examination, consideration and acceptance of gas estimates by the DGH.

(Para 2.6.2)

- The Operator was required to drill, connect and put on stream 22 wells under Phase I of approved AIDP. However, the Operator drilled, completed and connected only 18 wells. Gas production started declining in August 2010. While production level achieved in 2010-11 was 90 *per cent* of approved production profile, this figure decreased to 57 *per cent* in 2011-12 and 26 *per cent* in 2012-13. The Operator failed to adhere to the approved AIDP in terms of numbers of producer wells to be drilled and connected.

(Para 2.6.3)

- The Operator created facilities to handle gas production of 80 mmscmd. As of March 2012, the Operator had incurred expenditure of US$ 5.76 billion on the development of D1-D3 gas fields as against the MC approved cost of US$ 5.20 billion. The facilities created by the Operator remained underutilized / unutilized due to declining trend in gas production and non-drilling of wells as per the approved AIDP.

(Para 2.6.4 and 2.6.5)

Audit recommends that MoPNG may take urgent steps to resolve the differing views of the Contractor and DGH on the reserves estimates and take appropriate action to increase production.

- DGH approved Optimized Field Development Plan (OFDP) for four satellite discoveries. Initially, the OFDP was not techno-economically viable; however, it was made marginally viable by devising different scenario and changing assumptions, e.g. exclusion of royalty as expenditure, variation in capex etc.

(Para 2.6.6)

Audit recommends that MoPNG may consider fixing norms / criteria for working out techno-economic analysis of a FDP.

Expenditure related issues

- Engineering, Procurement, Installation and Construction (EPIC) contract of offshore facilities was awarded to M/s Allseas Marine Contractors (AMC) at a lump sum and provisional price of Euro 699.09 million and Euro 64.99 million respectively. Due to various factors attributable to Operator, AMC and its sub-contractors, AMC could not achieve the milestones. Concessions of Euro 200 million approximately given to AMC by the Operator in order to expedite completion of the works were not allowable for cost recovery as the concessions were not in line with EPIC contract including provisions relating to 'change in contract price'; and were in violation of Section 3.2 (ix) of Appendix C to the Accounting Procedure to PSC which states that, "*amounts paid with respect to non-fulfilment of contractual obligations are not recoverable and not allowable*".

(Para 2.7.1.1)

- Within four months from the date of signing the agreement, the Operator requested the FPSO vendor to extend the dry docking life of the FPSO from ten to fifteen years for a one-time compensation of US$ 17.36 million. Since the FPSO was chartered for 10 years only, extension of dry docking to fifteen years is not justified and the cost recovery of US$ 17.36 million may be disallowed.
- Despite the FPSO vendor being unable to meet its contractual obligations, the Operator re-scheduled the date of first production of oil (DFPO), without imposing any penalty. In addition, though there was no provision in the agreement which entitled the vendor to any compensation or incentive for expediting deliveries, the Operator paid compensation of US$ 45 million to the vendor for early mobilization of the vendor's commissioning team and expediting deliveries of top side modules etc., which may be disallowed.
- The FPSO has been leased for ten years. However, the Operator refurbished the existing living quarters and fabricated and installed additional living quarters, at a cost of US$ 15 million with the intention to purchase the FPSO at a later date. Audit recommends that the cost recovery of US$ 15 million may be disallowed.

(Para 2.7.1.2.1, 2.7.1.2.2 and 2.7.1.2.3)

- As per the Onshore Terminal (OT) construction contract, no compensation was payable to the vendor on account of Plant and Equipment (P&E) provided by RIL in case the vendor was unable to mobilize the P&E. However, an amount of INR 22.7 million was paid to the vendor as compensation charges for Cranes which were hired by RIL by amending the contract to exclude these cranes.

(Para 2.7.2.1)

- In four cost-plus contracts relating to construction of OT awarded by RIL, in general, payment of compensation was to be made to the vendors only on the 'cost' incurred by them. However, these contracts also provided for payment of mark-up to the vendor as a percentage of the value of free- issue material of some categories supplied by RIL such as cement, steel, etc. RIL incurred an expenditure of INR 1110.90 million on payment of such compensation.

(Para 2.7.2.2)

- Start-up and Production bonuses of US$12.48 million were paid to employees from the revenue earned from the Block. Since the Start-Up and Production Bonus are one-time and of an *ad hoc* nature, in Audit opinion, these bonuses should not be paid from the revenue earned from the sale of gas.

(Para 2.7.4)

- Despite having adequate drilling prospects and keeping in view the poor response received from the vendors for provisioning of the rigs indicative of the scarcity of deep-water drilling rigs, the Operator did not consider it prudent to consider the option of long-term hiring of the drilling rigs and availing the firm rate advantage of such long-term hiring. This resulted in additional expenditure of approximately US$ 88.77 million in piece-meal hiring of deepwater drill ship "Deepwater Frontier" from M/s Transocean Offshore International Ventures Limited.

(Para 2.7.5.1)

- Operator paid bonus for time saved during the rig movement between wells with hanging Blow Out Preventor (BOP). As per the contract clause, any bonus payment was to take into account the sum total of time saved for all the operational activities for completion of a well rather than a single activity. Therefore, payment of bonus for rig movement with hanging BOP was not justified and resulted in additional expenditure of US$ 2.83 million.

(Para 2.7.6.1)

- The Operator paid uptime bonus of US$ 13.37 million to M/s. Aker Contracting FP AS, Norway (ACFP), which resulted in additional benefit to the vendor, as normally bonus payments are extra payments given as a reward or incentive for earlier completion of work or increase in production level, not for performing their contractual obligations. In this case, ACFP was contractually bound to make available FPSO during the charter period.

(Para 2.7.6.2)

Revenue issues

- The pricing mechanism for Crude from MA oilfield has not been finalized and approved by MoPNG. The sales (under COSA) are being treated as provisional by the MoPNG. However, the Operator is treating the sales as firm and final. Marker has not been fixed so far leaving scope for ambiguity in pricing.

(Para 2.8.2)

- The pricing and sale of Condensate has not yet been approved by the Government. It is being sold at a discount value below Dated Brent. The difference between the sale value of Dated Brent and KG-DWN-98/3 Condensate amounted to US$ 33.93 million during the period July 2010 to March 2012.

(Para 2.8.3.2)

The PSC provisions relating to pricing and sale of Crude Oil and Condensate may be followed and decision on pricing and sale of Crude Oil and Condensate may be taken at the earliest.

- Operator is charging the gas price at the rate of US$ 4.340 mmbtu which includes 0.135 US$/mmbtu towards marketing margin from its consumers. Marketing margin is not being considered as revenue for the purpose of Cost Petroleum, Profit Petroleum and Royalty while Contractor has collected an amount of US$ 261.33 million on this account for the period 2009-10 to 2012-13.

(Para 2.8.3.1)

Accounting issues

- Parent Company Overhead (PCO) charged by the Operator for cost recovery up to the financial year 2007-08 under Section 2.6.2 of Accounting Procedure of PSC was disallowed by MC while adopting the Accounts for the year 2008-09, on the ground that Operator (RIL) has no parent company. However, Contractor has reclassified and claimed these expenditures amounting to US$ 101.41 million (upto 2011-12) under Corporate Office Support (COS). Such expenditure cannot be vouched by Audit in the absence of documentary evidence and by placing reliance only on the basis of a certificate of a Company Auditor appointed by RIL or a certificate given by the JV Auditor appointed by MC who in turn had relied upon the certificate given by the Company Auditor.

(Para 2.9.2)

- Closing stock of crude and condensate had not been accounted for in the books of the JV. Consequently, cost recovery of US$ 12.80 million towards the value of closing stock had not been adjusted for the years 2008-09 to 2012-13 and there was a short remittance of US$ 0.14 million of Profit Petroleum of closing stock for the years 2008-09 to 2012-13.

(Para 2.9.6)

Audit recommends that MoPNG may consider issuing audit exceptions under Section 1.9 of Accounting Procedure to the PSC in respect of expenditure related issues[1], revenue issues[2] and accounting issues[3] as per details given in the Report.

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[1] ***Para Nos. 2.7.1.1, 2.7.1.2, 2.7.2.1, 2.7.2.2, 2.7.3, 2.7.4, 2.7.5.2, 2.7.6.1, 2.7.6.2 and 2.7.7.1***

[2] ***Para No. 2.8.3.1***

[3] ***Para Nos. 2.9.2, 2.9.5, 2.9.6***

2.2 Panna-Mukta and Mid & South Tapti Fields (Joint Operators: BGEPIL, RIL and ONGC)

The Panna-Mukta and Mid & South Tapti Fields are offshore shallow water fields in the offshore Bombay Basin, which were initially discovered and operated by ONGC. Subsequently, these were awarded (1994) to a consortium of private parties under a JV arrangement with ONGC.

Issues relating to Arbitration

The partners RIL and BGEPIL served arbitration notice (December 2010) under PSC to GoI. The claims raised by RIL and BGEPIL pertain to i) Cost Recovery provisions under Panna-Mukta and Tapti PSC, ii) Calculation of IM, iii) Amount of royalty payable under PMT PSC, iv) Amount of cess payable by Contractor to GoI, v) Amount of service tax payable under PSC, and vi) Meaning and effect of Accounting and Audit provisions.

GoI also raised counter claim towards depressing expenditure allowance available under Section 42 of Income Tax Act, accounting of inflated sales, accounting of Development Cost in excess of cost recovery limit (CRL), short accounting of sales, sales revenue, marketing margin, income tax rate, non-completion of committed work programme as per Appendix-G, excess cost recovery over CRL.

The awards given by the Tribunal have been contested either by GOI or by the PMT JV partners (BGEPIL and RIL). All the afore-mentioned issues are *sub-judice* as on July 2014.

(Paras 3.3.4, 3.3.5 and 3.3.6)

Recoverable costs and cost recovery

- PMTJV charged production inventory to petroleum operations at the time of purchase instead of actual consumption as mandated by the PSC provision. As on 31 March 2012, PMTJV held production inventory worth US$ 26.15 million, which had been charged to cost recovery though not consumed. The cost recovery of production inventory without its actual usage for petroleum operations had adversely impacted GoI share of PP.

  (Para 3.6.1.3)

  Audit recommends that PMT JV may ensure that production inventory is charged to accounts only when such material is removed from inventory and used in petroleum operations as provided in the PSC.

- The JV has been booking rig mobilization charges to the cost of the first well and demobilization charges to the cost of last well irrespective of the number of wells drilled in the two fields. As the GOI Profit Petroleum of the two fields are at different slabs, the improper allocation of rig mob/demob charges may impact the Government take. Major E&P operators in India, i.e. ONGC and RIL (KG-DWN-98/3 Block), allocate rig mobilization and demobilization charges based on the actual number of days utilized in wells and number of wells drilled respectively. As different operators follow different methodologies, MoPNG/DGH ought to address the issue to decide a common acceptable method which would protect the interest of the Government.

(Para 3.6.1.1)

- PMTJV allocated the common personnel expenditure on 50:50 basis though these expenditures were identifiable for Panna-Mukta and Tapti contract area separately. As the profit petroleum percentage was different for these two contracts, such equal allocation impacted the GOI profit petroleum.

(Para 3.6.1.2)

Audit recommends that the common expenditure should be appropriately allocated to Panna-Mukta and Tapti fields on a reasonable basis viz. actual expenditure identifiable to a particular contract area or in the ratio of expenditure on the primary activity.

- As per the PSC, accumulation of surplus stocks should be avoided to the extent possible. Material and equipment held in inventory should only be charged to the accounts when such material is removed from inventory and used in Petroleum Operations. PMTJV recovered inventory carrying cost of US$ 549843 on the sparable drilling inventory till February 2009 impacting the GoI PP of US$ 90178.

(Para 3.6.1.4)

- The helideck and truss, cost of which was recovered, was not used by the PMTJV for almost seven years from the date of its removal from the deck and is yet to be disposed of. The total storage cost incurred for the helideck and truss was US$ 0.814 million (February 2009 to January 2014).

(Para 3.6.1.5)

Deficiencies in Contracting procedures and execution of Contracts

- The PMTJV hired a rig from its JV partner (M/s Reliance Industries Limited) on assignment basis at higher rates resulting in an extra expenditure of US$ 6.49 million which impacted GOI-PP by US$ 1.00 million (approximately).
- PMTJV in two instances awarded contracts on nomination basis without adhering to the contracting procedure stipulated in the Joint Operating Agreement at a higher rate compared to the estimated cost. As there was no price discovery, the reasonableness of the contract value could not be ascertained in Audit.

(Paras 3.6.2.1 and 3.6.2.2)

Petroleum saved and sold

- ONGC sold its share of gas to a private party (M/s Torrent Power Limited) at a price lower than the price prescribed in the PSC in contravention to MOPNG directives that led to loss of revenue. ONGC also did not reduce the sale of gas proportionate to the decline in production which also led to loss of revenue. The total revenue loss to ONGC was US$ 19.62 million and loss to GoI take was US$ 9.92 million.

(Para 3.6.3.2)

- PMTJV did not consider all the facilities used for petroleum operations (pre wellhead and post well head activities) for computing the well head value thereby impacting the royalty payable to the GOI by US$ 0.47 million. Upgraded reserves (1997 to August 2007) were not considered for amortization of CAPEX and remitting additional royalty payable to GOI.

(Paras 3.6.3.7 and 3.6.3.8)

Petroleum Operations

- PMTJV had commenced South West Panna Project without waiting for new seismic data leading to subsequent abandonment of the project which entailed infructuous expenditure of US$ 35.76 million.
- Delay in implementing water injection in Panna field resulted in decline in production. The value of decline in oil production during 2008-12 was to the extent of US$ 661.86 million.

(Para 3.6.4.1 and 3.6.4.2)

Compliance and Control Issues

- COSA had not been formalized by PMTJV with IOCL since 1994 due to non resolution of disputes on delivery point, storage charges, dead freight, voyage costs/losses etc. valuing Rs.724.18 crore (storage expenses) and Rs.63.56 crore (voyage expenses). MOPNG could not ensure signing of COSA between IOCL and PMTJV by expeditiously resolving the contentious issues.

(Para 3.6.6.1)

Audit recommends that GoI may ensure expeditious conclusion of COSA between IOCL and PMT JV by resolving the contentious issues; and PMTJV may ensure that (i) all facilities used for petroleum operations (pre wellhead and post wellhead activities) are considered for computing the wellhead value while arriving at royalty payable to GoI and (ii) also work out and remit the additional royalty to GoI by considering the upgraded reserves (1997 to August 2007) for amortization of capex.

2.3 RJ-ON-90/1 block (Operator: Cairn Energy)

This on-land block in Rajasthan was awarded in 1995 under pre-NELP rounds and is now operated by Cairn Energy. The block has twenty five discoveries (Oil: 22 and Gas: 3) out of which five oil discoveries were on production as on March 2012.

Compliance Issues

- Though the PSC stipulated that transportation cost beyond delivery point would be borne by the buyers, yet the Operator incurred US$ 8.87 million towards shipping of crude to MRPL and RIL beyond designated delivery point (Kandla) and adjusted it from the revenues. This adjustment resulted in short payment of Profit Petroleum to GoI by US$ 1.77 million.

(Para 4.2.4)

The Operator of RJ Block should carry out cost recovery in accordance with PSC provisions as any deviation in this regard would impact payment of PP to the GoI.

Revenue Issues

- The Government had designated (September 2005) MRPL as its nominee for the RJ crude. However, after a period of about eighteen months, MRPL expressed its inability to take RJ crude citing the characteristics of RJ crude (highly viscous with high pour point and residue) and its refining capacity. This adversely affected production and evacuation of crude from RJ block.

(Para 4.3.1)

- Inability of MRPL to lift RJ crude necessitated laying of pipeline from Barmer to Salaya which was completed in May 2010 against the scheduled completion by June 2009 after delay of about 10 months. The pipeline had to be extended from Salaya to Bhogat which though scheduled for completion by Q2 of 2010 was mechanically completed only in June 2014, nearly four years behind schedule. The Operator attributed the delay in completion to delays in securing Right of Uses (RoUs), in Rajasthan and Gujarat, unionization of farmers, local political agitations etc. Meanwhile, the pipeline cost rose to US$ 1108 million (March 2013) against the approved cost of US$ 941 million.

(Para 4.3.2)

- The Government refineries (IOCL, MRPL, HPCL and BPCL) having expressed (July 2005 and October 2008) their willingness and ability to take and process the RJ crude, failed to uplift their allocated share of RJ crude which led to controlled/moderated production of crude from the block during 2009-10 and granting marketing freedom (October 2009) to the Operator to sell the unallocated portion of the crude produced from the block to domestic private refineries, which took 51.11 to 87.57 *per cent* of the total production from the block from 2009-10 to 2011-12.

(Para 4.3.3)

- Two spur lines (on the Barmer to Salaya pipeline) at Radhanpur and Viramgam (additional delivery points) to facilitate delivery of RJ crude to IOCL's Panipat and Koyali refinery respectively (Cost: US$ 58.84 million) remained largely underutilized due to failure of IOCL to uplift allocated quantity of RJ crude.

(Para 4.3.4)