CHAPTER XIV : MINISTRY OF PETROLEUM AND NATURAL GAS

14.1 Follow up Audit of Hydrocarbon Production Sharing Contract for KG-DWN-98/3 Block for the Financial Years 2012-13 and 2013-14

Many of the issues that had been pointed out in previous audits (2006-12) of the PSC block still persist. The total financial impact of excess cost recovery during 2012-14 on account of the earlier identified audit findings was USD 1547.85 million (₹ 9307.22 crore). For the period 2012-14, additional issues of excess cost recovery claimed by the operator were noticed, financial effect of which was USD 46.35 million (₹ 278.70 crore). Cost recovery has been claimed on testing (MDT) for the wells D29, D30 which needs to be appropriately assigned and reversed in view of the recent MoPNG directive (May 2015). Operator had relinquished D31 discovery and all cost recoveries connected to this discovery need to be reversed. Meanwhile the report of independent expert M/s DeGolyer & MacNaughton (D&M) has indicated migration of gas from adjacent block operated by ONGC to KG-DWN-98/3 block, which may affect the financials of this block.

14.1.1 Introduction

In April 2000, GoI awarded the KG-DWN-98/3 Block (KG-D6 block) to a consortium led by Reliance Industries Limited (RIL) through a global competitive bidding process under the New Exploration Licensing Policy (NELP)–I round. RIL had a 90 *per cent* participating interest (PI) and a Canadian Company, Niko Resources Limited (Niko) held the balance 10 *per cent* PI. In 2011, RIL assigned its 30 *per cent* PI to BP Exploration (Alpha) Limited (BP). As of March 2014, the '**Contractor**' comprised RIL, BP and NIKO with 60, 30 and 10 *per cent* PI respectively. RIL continued as the '**Operator**' of the Block.

The production sharing contract (PSC) for the KG D6 block was signed in April 2000. Based on exploration activities carried out between 2002 and 2012, a total of 19 hydrocarbon discoveries were made in the block. Of these 19 discoveries, one {D26 (MA oilfield)} is primarily an oil discovery and the remaining are gas discoveries. Oil production from MA oil field started in September 2008 while gas production from D1-D3 field started in April 2009.

14.2 Performance Analysis

14.2.1 Cumulative Financial Details:

Table 1: Details of expenditure, sales revenue, profit petroleum (PP) for the years 2012-13 and 2013-14 (as reported by the Operator)

(Amount in million US$)

Particulars	2012-13	2013-14	Cumulative as on 31.3.2014
Expenditure	436.23	615.31	11,057.29
Sales revenue	1637.00	904.92	11,073.65
Incidental income	62.77	0.84	157.91
Total revenue	1699.77	905.76	11,231.56
Cost recovered	1529.79	815.18	10,108.40
PP	169.98	90.58	1,123.16
PP GoI share (10 per cent)	17.00	9.06	1,12.31
PP Contractor share	152.98	81.52	1,010.84

The total expenditure incurred in the block till March 2014 was US$ 11,057.29 million (Exploration: US$ 1095.18 million, Development: US$ 7,752.03 million and Production: US$ 2,210.08 million).

14.2.2 Issue regarding drawl of gas from contiguous blocks of ONGC

The KG-DWN-98/3 block is contiguous to ONGC blocks in the Eastern offshore (KG-DWN- 98/2 and Godavari PML area). ONGC apprehended (December 2013) that the reservoir of its blocks extends into KG-DWN-98/3 block and that four wells drilled in KG-DWN-98/3 by the Contractor was actually draining gas from this common reservoir. The matter was taken to the High Court of Delhi (May 2014) which disposed the case in September 2015 directing the Government to take a decision on the action to be taken within a period of six months after receiving the report from an independent panel, appointed with consensus of both ONGC and RIL in July 2014, to evaluate reservoir continuity across block boundaries. The independent expert, M/s DeGolyer & MacNaughton (D&M), has since submitted (November 2015) its report.

The report indicates that as on 31 March 2015, of the gas initially in place, 49.32 *per cent* in Godavari PML and 34.71 *per cent* in KG-DWN-98/2 (Cluster I) had migrated of which 85.15 *per cent* (pertaining to Godavari PML) and 73.25 *per cent* (pertaining to KG DWN98/2) was produced through DI-D3 fields of KG-DWN-98/3 block. The report projected a higher proportion of gas migration and its production through RIL operated KG-DWN-98/3 block by end of 2019.

On the basis of D&M report, Government has appointed (December 2015) a one member committee (Justice A. P. Shah) to consider the report and recommend future action of the Government, considering the legal, financial and contractual provisions including those contained in the ORD[1] Act and the PSCs within a period of three months.

In case if the MOPNG accepts D&M report conclusion that RIL did draw gas from ONGC's contiguous fields, and directs RIL to compensate ONGC for the same, it may affect the financials of KG-DWN-98/3 including Cost Petroleum, Profit Petroleum, Royalty and taxes over its entire period of operation (since April 2009 when production of gas commenced from the block).

14.3 Audit Findings

14.3.1 Persistent issues highlighted in the past reports

Audit of the records of the operator of the KG-DWN-98/3 Block was conducted for the period from 2006-07 to 2011-12 along with performance audit of MoPNG and DGH, in two spells. The audit findings were reported in two reports, CAG Audit Report (AR) No. 19 of 2011-12 and Audit Report No. 24 of 2014. Both reports had highlighted instances of excess cost recovery recommending their disallowance. The para-wise summary of the action taken by MoPNG including issue of audit exceptions against Audit Report 24 (which is a follow up audit of Audit Report No.19) and their current status is at **Annex-III**. Audit observed that the Operator continued to claim excess cost recovery on identical issues during 2012-13 and 2013-14 despite the issues having been highlighted in previous Audits. The specific instances of persistent excess cost recovery are given below:

14.3.1.1 Underutilization of gas handling facilities due to non-achievement of production as envisaged in the approved AIDP

The non-achievement of approved production targets of 80 MMSCMD[2] as per Addendum to Initial Development Plan (AIDP) and under-utilisation of facilities had been commented in AR No. 24 of 2014 (paragraph 2.6). MoPNG had advised (May 2012) that the Operator was not entitled to recover

[1] ORD: Oil fields (Regulation and Development) Act, 1948
[2] MMSCMD-Million Metric Standard Cubic Meters per day

cumulative cost of excess capacity amounting to US$ 1005 million (₹ 6043 crore)[3] created in the block up to the year 2011-12. Despite MoPNG's directive, the Operator continued to include this amount in the cost recovery for 2012-13 and 2013-14.

Since the actual cumulative production in D1-D3 discoveries as compared to AIDP targets was lower by 39.23 *per cent* up to the FY 2012-13 and by 51. 5 *per cent* up to the FY 2013-14 than the MC approved target of AIDP, MoPNG worked out the additional amount inadmissible for recovery during this period. The amount disallowed by MoPNG for the FY 2012-13 was US$ 792 million (₹ 4762.29 crore) and for 2013-14 was US$ 579 million (₹ 3481.52 crore). In all, a cumulative cost recovery of US$ 2376 Million (₹ 14286.88 crore) has been disallowed up to FY 2013-14 towards unutilised cost of production facilities. MoPNG had intimated to the Operator (July 2014) that the additional profit petroleum (provisional) payable to the Government by the Contractor for period upto the financial year 2013-14 was US$ 195.34 million (₹ 1174.58 crore) (US$115 million upto 2012-13 and US$ 80 million for 2013-14). MoPNG had also directed to remit the additional profit petroleum within 30 days from the date of receipt of the direction which has not been complied with by the Operator.

The Operator in reply stated (August 2015) that the issue is under arbitration and therefore, *sub-judice*. Operator refrained from providing its comments on the subject to avoid any potential prejudice to either party to the arbitration.

The DGH in reply stated (July 2015) that the Contractor is yet to remit Profit Petroleum short paid.

14.3.1.2 Marketing Margin on Gas Produced and Sold

As brought out in the previous Audit Report (para no.2.8.3.1 of CAG report No. 24 of 2014), the Operator charges separately for gas price and marketing margin from its customers. The gas price is charged @ US $ 4.205/mmbtu and an additional US $ 0.135/ mmbtu is charged on account of marketing margin. However, while computing the PP and Royalty, the Operator considers the gas price (@ US $ 4.205/mmbtu) alone which has an impact on cost recovery, PP and royalty. On being pointed out by Audit, MoPNG had stated (June 2014) that

[3] Rate used to convert amounts in US$ to Indian ₹ 1US$= ₹ 60.13 as on 27 March 2014

the proposal to include marketing margin for royalty computation is being examined.

Audit noticed that the earnings through marketing margin during the FY 2012-13 and 2013-14 was US$ 63.78 million (₹ 383.51 crore) (US$ 41.65 million for the FY 2012-13 and US$ 22.13 million for 2013-14) which has not been treated as revenue having an adverse impact on cost recovery, PP and royalty (**Refer Annex-IV** for details).

The Operator, reiterated (August 2015) that there is no legal or commercial basis which requires the Contractor to include marketing margin while calculating the value of the Petroleum produced and saved from the Contract Area.

Audit reiterates that the Operator's reply is not in consonance with the contractual provisions of the PSC. Article 27.2 of the PSC states that title to petroleum sold by the Companies shall pass to the relevant buyer party at the Delivery Point. As per clause 6 (a) of GSPA, the Sale Price of gas at delivery point shall be the sum of the Gas Price in US$/mmbtu (NHV[4]) and the marketing margin in US $/mmbtu (NHV). The revenue, thus, ought to include the marketing margin.

The final decision of the Ministry in this regard is awaited.

14.3.1.3 Payment of US$ 10.13 Million Uptime Bonus for chartering FPSO

Audit has pointed out (para 2.7.6.2 of Audit Report no. 24 of 2014) that the Operator has paid uptime bonus to M/s Aker Contracting FP AS Norway (ACFP) for availability of FPSO[5] facility (hired from ACFP). This led to additional benefit to ACFP as availability of FPSO was a contractual provision. Ministry has also issued an Audit exception on the matter. Audit, however, noticed that the practice of payment of uptime bonus to ACFP for meeting the contractual condition of availability of FPSO, continued through FY 2012-13 and 2013-14. This led to an additional benefit of US$10.13 million (₹ 60.91 crore) to ACFP

4 Net Heating Value
5 FPSO-Floating, Production, Storage and Offloading

The Operator stated (September 2015) that ACFP is required to discharge its obligations on a continuous basis for efficient maintenance and repairs of the FPSO and has also specified a list of duties that ACFP has to carry out in this regard. The Operator also pointed out (April 2015) that it does not accept the Audit exception issued by MoPNG in this regard.

Audit reiterates its earlier observation. The Operator's reply cannot be accepted as ACFP is contractually bound to discharge its obligation. Article 8.5, 8.11, 8.17 and Exhibit D of the Contract requires ACFP to maintain the FPSO in fit and good condition for intended work and to comply with all quality control procedures, standards and guidelines. Hence the duties specified by the Operator were part of the contractual obligations of ACFP, for which no additional payment was required.

14.3.1.4 Unconnected wells

Audit had pointed out (para no. 2.6.3 of AR 24 of 2014) that the 50 wells planned to be drilled as per Addendum to Initial Development Plan (AIDP) by July 2013 could not be completed. Instead, the Operator could drill, complete and connect only 18 wells till 31March 2014. Audit had also highlighted that another four wells, namely A21, A22, B16 and SB1 had been drilled (August 2010 to August 2011), but had not been connected to the production facilities despite directives of DGH.

Audit noticed that the Operator has not connected (August 2015) these four wells. Operator has justified its action stating that these wells would not produce adequate incremental volume to justify the additional capex spend on completing and connecting them. DGH, however, has not agreed and has again directed (June 2014) the Operator to urgently take action to put these wells on production to realize the gas gain from the known and the new layers encountered therein. The Operator, however, has not taken further action in the matter. Though these wells have not contributed to production from the D1-D3 field, the Operator has recovered US$ 102.94 million (₹ 618.98 crore) upto the FY 2013-14 towards their cost.

The Operator, stated (August 2015) that since costs for drilling these wells have been incurred while conducting Petroleum Operations, such costs have been rightly included in Contract costs for cost recovery. None of the PSC provisions bar inclusion of such costs in the Contract costs, thereby supporting the

Operator's firm opinion. The Operator has further stated (October 2015) that the matter is under Arbitration.

14.3.1.5 Relinquishment of excess area held by Contractor

Audit had pointed out (para no 2.5.1 of AR 24 of 2014) that the entire contract area of the Block had been treated as 'discovery' area and retained by the Contractor. In October 2013, MoPNG directed the Operator to relinquish an area of 6198.88 sq.km out of the total contract area of 7645 Sq. Kms, allowing retention of 1148.12 Sq. Km under Petroleum Mining Lease. The issue relating to relinquishment of D29, D30 and D31 (area of 298 Sq.Km.) was being considered separately. However, contrary to MoPNG's directives, the Operator relinquished only an area of 5367 sq.km retaining an excess area of 831.88 sq.km. The Operator has also paid Petroleum Exploration License (PEL) fees of ₹ 3.32 Million relating to the excess retained area.

The Operator, in reply, has stated (August 2015) that audit observation relates to payment of PEL fees for the period from June 2014 to June 2015 and is outside current CAG audit. Operator has correctly paid the PEL fees during the audit period.

DGH, in reply, has stated that the Operator was informed that excess amount of PEL fees paid by the licensee shall be required to be adjusted against fee for PEL/PML[6] for subsequent year or any other area held by the licensee under Rule 11(2) of Petroleum and Natural Gas Rules, 1959.

The area relinquished by the Operator is not as per the MoPNG's directives of October 2013. Relinquishment of the additional area retained needs to be ensured by the Ministry. Alongside, excess payment of PEL fees need to be adjusted.

14.4 Observations arising from audit of documents pertaining to Financial Years 2012-13 and 2013-14

Audit verified the revenues received and the costs incurred during FY 2012-13 and 2013-14. In particular, tendering and award of contracts, their execution and payments made against them during this period were scrutinised[7]. Audit observed non-compliance of PSC provisions, costs recovered despite being

[6] Petroleum Mining Lease

[7] 100% of contracts (21) of more than US$ 50 lakhs, 75% of contracts (10) between US$ 25 to 50 lakhs, 25% of contracts (8) between US$10 to 25 lakhs and 5% of contracts (10) of less than US$ 10 lakhs were scrutinised.

dis-allowed/not approved by MC. Instances of non-compliance of MoPNG directives, DGH instructions were also noticed. The issues noticed are detailed below.

14.4.1 Issues relating to Expenditure

14.4.1.1 Non adherence to the testing process mandated by PSC

The Operator had submitted Declaration of Commerciality (DoC) proposals in February 2010 for four discoveries namely D29, D30, D31 and D34 for Management Committee (MC) review. Drill Stem Test (DST) was not carried out for all four discoveries. As such, MC was unable to review these discoveries. With submission of additional information on D34 discovery, MC reviewed this discovery without insisting on DST. Audit in its previous report (paragraph No.2.5.1 of C&AG of India Audit Report No. 24 of 2014) had recommended that cost of wells drilled in the D29, D30 and D31 areas be disallowed if they are not found commercially viable subsequently.

In May 2015 (vide Notification dated 13 May 2015), MoPNG provided three alternatives to the defaulting Contractors who had not met DST testing requirement for discoveries. The notification specifically mentioned the three discoveries, D29, D30 and D31 for which DST had not been carried out. The options *inter-alia* provided were:

- Option-1: relinquish the contract area related to discoveries;
- Option-2: conduct fresh test and submit revised DoC with a stipulation that only 50 *per cent* of cost incurred for testing (DST) will be allowed for cost recovery with a cap of US 15 million. The cost of MDT incurred by the contractors earlier in respect of such discoveries would not be allowed for cost recovery, and
- Option-3: proceed for development of discovery without conducting DST, but cost recovery of such development would be ring fenced. The cost recovery would be permitted only when these discoveries finally turn out to be commercial.

As per the notification, the option had to be selected by end June 2015 (within 60 days of CCEA approval of 29 April 2015).

Accordingly, for the three discovery areas, the Operator has decided to relinquish D31 and carry out DST for D29 and D30. The MC approved

(July 2015) the addendum to BE 2015-16 Work Programme & Budget (WP&B) for carrying out DST in discoveries D29 and D30 in the Block in accordance with GOI policy dated 13 May 2015. In this context, Audit has the following observations:

- As D31 would be relinquished by the Operator, the entire cost incurred on D31 ought to be disallowed in line with the previous audit recommendation. The cost incurred on discovery of D31 was US$15.13 million (₹ 90.98 crore) which needs to be disallowed. Additional costs have subsequently been recovered on its appraisal, cost recovery continuing even during FY 2012-13 and 2013-14. However, Audit noted that the Operator has not maintained cost records for appraisal of each discovery area, separately. As such, the appraisal costs pertaining to D 31 could not be worked out in Audit. It is necessary to appropriately allocate appraisal costs to D 31 and disallow these expenses.

- The discovery and appraisal costs of D29 and D30 can be recovered only in case these discoveries are found to be commercially viable based on DST. It was noticed that the Operator has continued to recover costs for these discoveries (US$1.19 million in FY 2012-13 and US$3.75 million in FY 2013-14 for D29, D30 and D31). The recoverability of expenses relating to D29 and D30 would depend on the commercial viability of the discoveries.

- As per the MC approval (July 2015) given under directive of MoPNG (notification dated 13 May 2015), the cost of MDT in D29 and D30 will not be allowed for cost recovery. The Operator did not maintain separate MDT costs for each discovery. On being pointed out by Audit, the Operator intimated (October 2015), that the cost of MDT for D29 was US$ 84832.23 and for D30 was US$ 103435.35. However, the Operator has worked out this quantum through allocation of the total MDT cost on the basis of rig movement, irrespective of whether MDT was performed at the site or not. As MDT is a specialised service, its cost needs to be assigned to the specific wells where the test is carried out. In absence of such specific information, Audit cannot comment on the accuracy of the MDT cost of D29 and D30 as worked out by the Operator.

The Operator intimated to MOPNG that D31 has been relinquished and DST would be conducted for D29 and D30. The Operator also stated (August 2015) that expenditure was incurred on D29 and D30 discoveries for integrated development with adjacent discoveries.

In view of the confirmation of the Operator regarding relinquishment of D31, the cost recoveries on discovery and appraisal pertaining to D31 needs to be worked out and reversed. The recovery of costs incurred on D29 and D30 would depend on commercial viability of these discoveries following DST. The MDT cost of D29 and D30 needs to be appropriately assigned and reversed.

14.4.1.2 Allocation of expenditure to cost recovery of services not utilized in the approved area

The Operator had submitted (October/November 2012) a proposal to undertake DST in one of the discoveries – D29, D30 and D31. The proposal was subsequently revised (May 2013) to undertake DST in all three wells. The budget estimates for conducting DST in these three discoveries was US$ 93 million (as per the WPB for the FY 2013-14).

The Operator awarded (April 2013) the contract for DST services to M/s. Schlumberger Asia Services Limited. However, the services were not utilised for the three earmarked discoveries (D-29, D-30, and D-31) in KG-DWN-98/3 block but for discoveries in other discovery areas/blocks, viz., MJ and CYD5. Audit noticed that the Operator has charged an amount of US$ 4 million on account of DST to the KG-DWN-98/3 block (the details are at **Annex-V**), though DST services were not utilized in the approved areas of the block. This has increased the cost recovery for block KG-DWN-98/3 and adversely affected its profit petroleum.

The Operator in reply stated (August 2015) that the rental charges of DST services have been charged to various blocks based on the deployment of the rigs. This is due to the fact that the components of the DST package are used not only during DST operations but also during completion/work-over operations as and when required. Considering that it is a long lead item, the whole package is mobilised by Operator and maintained to ensure unhindered operations at all times. Accordingly, irrespective of whether actual DST operations have been carried out or not, the cost associated with the services were charged to the wells (exploratory or otherwise) which were drilled during the period and no cost has been booked in discovery D29, D30 & D31.

The reply is not acceptable in view of the following:

- DST is a specialised service which, though intended for D-29, D-30 and D-31 in KG-DWN-98/3 block was not utilised in those discovery areas at all. Instead, the services were utilised in CY-DWN block governed by separate PSCs and MJ area. As per para 2.2 of section 2 of the PSC, all direct and allocated indirect expenditures of exploration costs incurred in the search for petroleum is to be booked to that area. As such, the cost of the specialised DST services should be allocated to the areas on actual utilisation basis and not based on the deployment of the rigs.

Thus, the entire cost of the DST services should have been charged to wells in CY-DWN block and MJ discovery area where the services were actually utilised. By allocating these costs to KG-DWN-98/3 block, the cost recovery for the block was overstated by US$ 4 million (₹ 24.05 crore) with commensurate adverse impact on profit petroleum.

14.4.1.3 Additional cost recovery of US$ 10.12 million towards Rig standby charges due to not carrying out up gradation/modifications prior to mobilisation of Rig

During April 2008 the operator entered into a contract with M/s. Deepwater Pacific 1 Inc. for charter hire of rig Dhirubhai Deepwater KG2 (DDKG2) for a period of 60 months from date of completion of its mobilisation. The rig was constructed and mobilised in March 2010. The Operator, subsequently, requested the contractor to carry out upgradation of the rig DDKG2 (March 2011). The up-gradation of the rig was essential, inter alia, as there was water production in the field. The up-gradation was completed by January 2012. The rig remained on standby during the period of its up-gradation. The operator paid an amount of US$ 10.12 million as Rig standby charges during the period of up gradation/modifications.

Audit observed that water production in D1-D3 had been noticed since October 2009, much before mobilisation of the rig, DDKG2. As such, the Operator should have planned and carried out the up-gradation of the rig during its construction (before mobilisation) period, which would have avoided standby charges of US$ 10.12 million.

The Operator in reply stated (September 2015) that the initial survey of the rig for the purpose of work-over system was carried out in February 2010. Accordingly, service providers submitted quotes and delivery of long lead rig specific items. The landing string contract was committed by Operator on May 10, 2012. This necessitated further rig surveys, considering different functionality and footprints of their equipment. Once the intervention and work-over campaign was confirmed, up-gradation works were commenced. These were major reasons for not carrying out the modifications / up-gradations before mobilization of the Rig DDKG2 (March 2010).

The reply is not acceptable as the AIDP for KG-DWN-98/3 block had been approved by the MC in December 2006. As per the AIDP targets, the Operator was required to drill 50 producer wells in D1 D3 area of the KG-DWN-98/3 block. As there was an existing plan for drilling development wells at the time of entering into the contract for hiring of the Rig DDKG2, and as water production had been observed necessitating up-gradation of the rig before its mobilisation, the Operator ought to have taken up up-gradation of the rig earlier. Taking up up-gradation of the rig as a separate project, post mobilisation led to avoidable expenditure on standby charges amounting to US$ 10.12 million (₹ 60.85 crore). As these charges have been cost recovered, this led to excess cost recovery which adversely affected profit petroleum and Government take.

14.4.2 Issues Relating to Revenue

14.4.2.1 Non receipt of refund of Indian Withholding tax outstanding due to losses incurred by M/s. Aker Contracting FP ASA

The Operator had awarded a contract for hiring an FPSO to M/s. Aker Contracting FP ASA, Norway (Aker) in May 2007. Clause 5.4 of the contract, *inter-alia* provides that the Indian Withholding Tax is applicable to payments to be made by the Contractor to Aker @ 4.182 *per cent* under the Income Tax Act 1961. As per the agreement between the Kingdom of Norway and Republic of India for avoidance of double taxation, Aker is eligible for deduction from tax on income in its country of residence, an amount equal to the income tax paid in India. This credit is to be passed on by Aker to the Contractor.

However, on account of losses incurred by Aker, it does not pay taxes in its country of residence. Hence no credit is being passed on to the Contractor. Over the period 2009-13, the Contractor has forgone credit of NOK 131.61 million

(US$ 17.10 million ~ ₹ 102.82 crore) on this account. The Operator should ensure reimbursement of the amount of withholding tax paid.

The Operator, in reply, has noted (August 2015) the suggestion of Audit and assured that Operator would ensure getting credit from the vendor provided the vendor gets tax credit in respect of Withholding Tax paid in India in its country of residence.

14.5 Conclusion

The implementation of hydrocarbon PSC in KG DWN-98/3 block over the period 2006-12 had been audited and reported upon earlier (Audit Report (AR) No. 19 of 2011-12 and AR No.24 of 2014). During the course of present audit covering the period 2012-14, it was noticed that many of the issues that had been pointed out in previous audits and on which audit exceptions have been issued by the Ministry, still persist. The total financial impact of excess cost recovery during 2012-14 on these items was USD 1547.85 million (₹ 9307.22 crore). The operator has invoked arbitration on some of these exceptions (under-utilisation of gas handling facilities, un-connected wells) and these matters presently stand un-resolved.

During the current audit covering the period 2012-14, additional issues of excess cost recovery were noticed, the net excess cost recovery taken by the operator on these items being USD 46.35 million (₹ 278.70 crore). A significant issue noticed in course of the present audit is the cost recovery made on testing (MDT) for the wells D29, D30 which needs to be appropriately assigned and reversed in view of the recent MoPNG directive (May 2015). Besides, the Operator has relinquished D31 discovery and all cost recoveries already made, connected to this discovery would need to be reversed. Other instances of excess cost recovery by the Operator were noticed including allocation of costs to the block for services used in other blocks, etc.

Besides, the report of independent expert M/s DeGolyer & MacNaughton (D&M) submitted in November 2015 on reservoir continuity between the KG-DWN-98/3 and contiguous ONGC operated blocks has pointed out that gas has migrated from the ONGC block to the KG-DWN-98/3 block, a substantial portion of which has already been produced, which may affect the financials of the KG-DWN 98/3 block. The report is presently under the consideration of a one-member committee.

The Report was issued to the Ministry of Petroleum & Natural Gas in October 2015. Reply of the Ministry to the same was awaited (February 2016).