Chapter-2

Audit Findings in respect of KG-DWN-98/3 Block

Chapter 2 - Audit Findings in respect of KG-DWN-98/3 Block

2.1 Overview

2.1.1. Exploration efforts in the past two decades have proven that the hydro-carbon potential of the Krishna-Godavari (KG) basin in the Bay of Bengal is of significant commercial interest. Several oil and gas fields are located in both onland and offshore parts of the basin. The KG-DWN-98/3 (also referred to as KG-D6) block, with a contract area of 7645 square km (sq. km.), is one such 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.

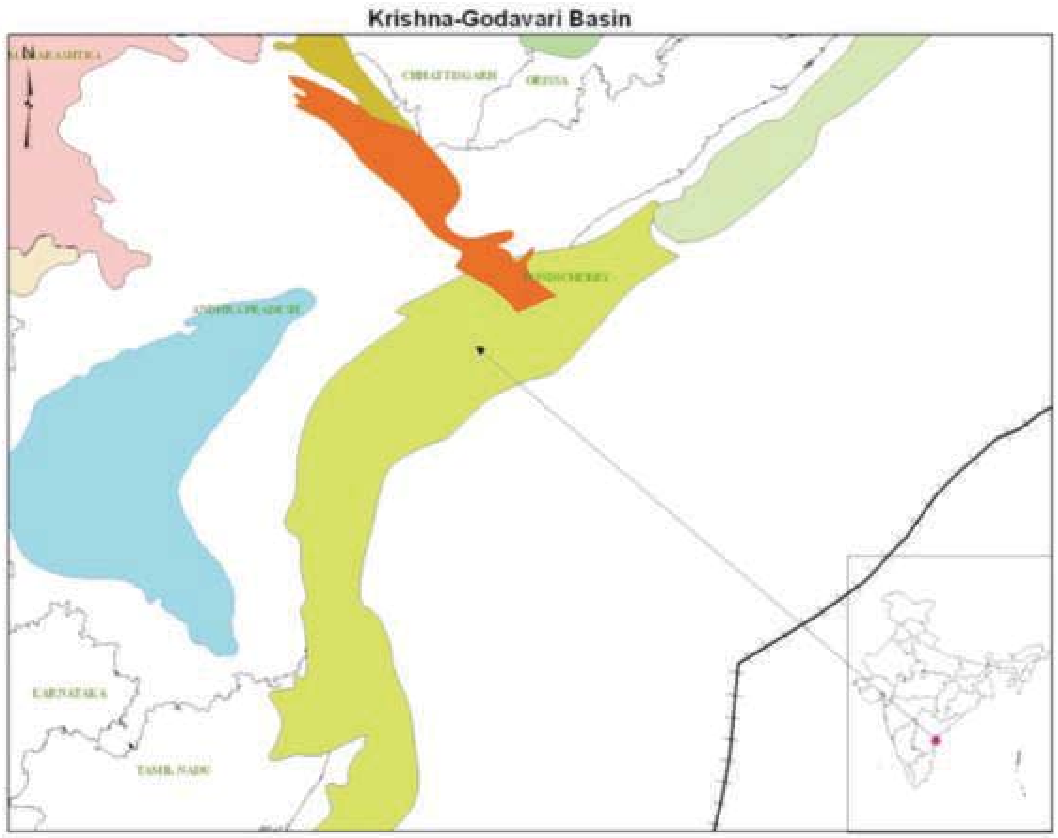

Figure 2

2.1.2. In April 2000, GoI awarded the KG-DWN-98/3 Block to a consortium led by Reliance Industries Limited (RIL) with a 90 *per cent* PI through a global competitive bidding process under the NELP – I round. Till August 2011, the only other member of the consortium was a Canadian company, namely Niko Resources Limited (NIKO). In 2011, RIL assigned its 30 *per cent* PI to BP Exploration (Alpha) Limited (BP). Thus, as of July

2014, the 'Contractor' comprised RIL, BP and NIKO with 60, 30 and 10 *per cent* PI respectively. RIL, however, continued to remain the 'Operator'[9] of the Block.

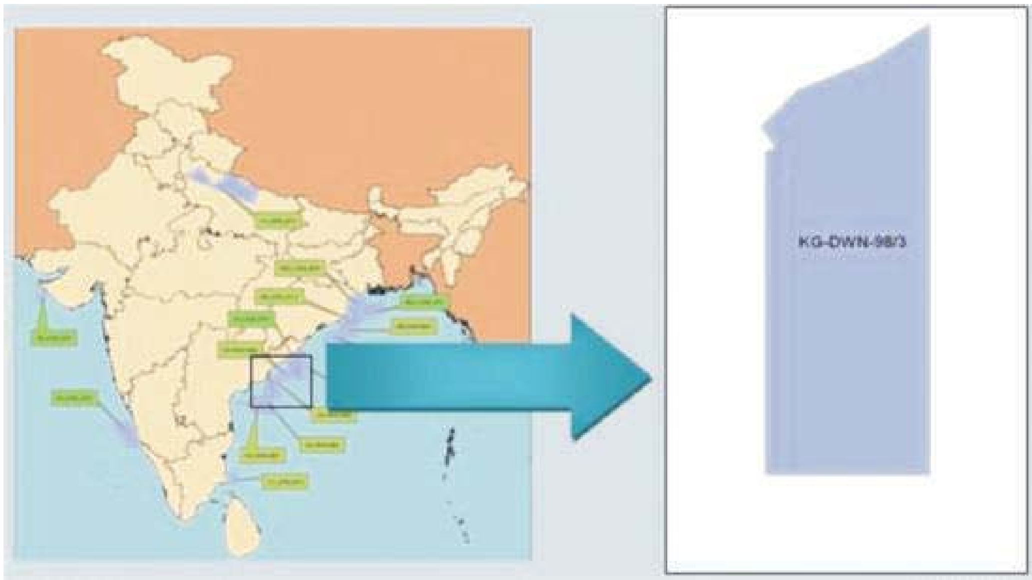

Figure 3

2.1.3. Subsequent to the signing of PSC in April 2000, based on exploration activities between 2002 and 2012[10], a total of 19[11] hydrocarbon discoveries had been made in the Block. Out of these 19, one discovery {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.

2.1.4. Financial details

Cumulative financial details of the KG-DWN-98/3 Block are as follows:

Table 3 : Cumulative financial details

(Amount in US$ million)

	As of 31 March 2012	As of 31 March 2013
➢ **Expenditure**	10,005.75	10,441.98
➢ **Sales and other income (net)**	8,626.03	10,325.80
➢ **Cost Recovered**	7,763.43	9,293.22
➢ **Unrecovered Cost**	2,242.32	1,148.76

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[9] *'Operator' means one of the parties comprising Contractor appointed as the Operator pursuant to Article 7 of PSC.*

[10] *There was no fresh discovery during 2008-2012.*

[11] *Dhirubhai (D) 1,2,3,4,5,6,7,8,16,18,19,22,23,26,29,30,31,34 and 42.*

	As of 31 March 2012	As of 31 March 2013
➢ **GoI share**		
○ **Royalty**	431.70	513.46
○ **PP (10 *per cent*)**	86.26	103.26
➢ **Contractor share**		
○ **Cost Recovery**	7,763.43	9,293.22
○ **PP (90 *per cent*)**	776.34	929.32

Expenditure - The total expenditure incurred in the Block till March 2013 was US$ 10,441.98 million, *i.e.* Exploration US$ 1,095.41 million, Development US$ 7,572.78 million and Production US$ 1,773.79 million. Details of expenditure, sales revenue, PP for the years 2008-09 to 2012-13 are as under:

Table 4 : Details of expenditure, sales revenue, profit petroleum for the years 2008-09 to 2012-13

(Amount in US$ million)

Particulars	2008-09	2009-10	2010-11	2011-12	2012-13	Cumulative as on 31.3.2013
Expenditure	2,744.28	1,929.29	804.46	532.27	436.23	10,441.98
Sales revenue	41.53	2,229.63	3,504.05	2,756.51	1,637.00	10,168.73
Incidental Income	11.43	8.48	46.66	27.74	62.77	157.07
Total revenue	52.96	2,238.11	3,550.71	2,784.25	1,699.77	10,325.80
Cost recovered	47.66	2,014.30	3,195.64	2,505.82	1,529.79	9,293.22
PP	5.30	223.81	355.07	278.43	169.98	1,032.58
PP GoI share (10 *per cent*)	0.53	22.38	35.51	27.84	17.00	103.26
PP Contractor share	4.77	201.43	319.56	250.59	152.98	929.32

Physical performance parameters - The details of Sales[12] (product-wise) reported by the Operator for the period 2008-09 to 2012-13 are as under:

Table 5 : Sales for the period 2008-09 to 2012-13

(Amount in US$ million)

Year	Gas		Crude Oil		Condensate	
	Quantity (in mmbtu[13])	Amount	Quantity (in Barrels - BBLs)	Amount	Quantity (in BBLs)	Amount
2008-09			881,067	41.53		
2009-10	460,353,175.90	1,935.79	4,000,755.00	293.84		
2010-11	659,244,545.89	2,772.12	7,994,514.86	685.15	750,395.618	46.78
2011-12	507.646,842.08	2,134.65	4,943,783.00	553.10	735,777.159	68.76
2012-13	308,545,025.19	1,297.43	2,916,831	306.36	389,762.636	33.21

2.1.5. Presentation of audit findings in this chapter

Para 2.2 of this report contains the sampling methodology adopted. Para 2.3 details the constraints faced during field audit relating to the access and non-production of records. Regulatory issues observed during performance audit at MoPNG / DGH are in Para 2.4, 2.5, 2.6 and 2.10. Audit objections in respect of expenditure related issues noticed during the audit of Contractor's records are detailed in Para 2.7. Observations on revenue and accounting issues are contained in Paras 2.8 and 2.9 and primarily emanate from the audit at the Contractor and MoPNG / DGH.

2.2 Sampling methodology

Audit reviewed on a random basis, 50 *per cent* of sales invoices generated with respect to the crude oil and condensate sale agreements and 30 *per cent* with respect to natural gas sales in each year of the audit period. Further, sample size with respect to statements for calculation of royalty and profit petroleum and its remittance was 75 *per cent*. Audit selected high-value procurements and reviewed 102 contracts valuing US$ 654.85 million (approximately) out of the total contracts valuing US$ 1736.26 million pertaining to the period 2008-09 to 2011-12 (please refer to audit comment on list of purchase orders in para 2.3.2). In addition, Audit

[12] *Source of data: Sales Statements for the year 2008-09 to 2012-13.*

[13] *Million Metric British Thermal Units.*

also examined invoices worth US$ 1725.07 million pertaining to certain contracts[14] awarded in the period prior to 2008-09 payments for which were made during the audit period. However, the process of sample selection and scope of audit was affected due to restricted and delayed access to SAP, delayed production of list of purchase orders and non-production of records as discussed in para 1.6, para 2.3 of the Report.

2.3 Audit constraints

2.3.1 Restricted access to SAP

2.3.1.1. The accounts of all domestic blocks belonging to the Operator are maintained in a SAP ERP system. The books for each block are inter-linked in SAP.

2.3.1.2. Auditors need extensive authorizations, from the administrator of the system, within the SAP system in order to perform required activities.

2.3.1.3. For this purpose, every SAP installation offers standard profiles. Customized profiles usually do not enable auditors to fulfil their tasks. From the audit point of view the most important modules in SAP where access is required are Sales and Distribution; Procurement and Payables; General Ledger; Human Resources; Project System; and Asset Accounting *etc*. With complete access to all the modules of SAP, one can download the data of all the transactions pertaining to this block and analyse selected data in various and complex ways, which is not possible in the SAP system itself. However, in case of customized profiles, as given to auditors by the Operator, it was not possible to extract the required data in all the cases and perform the analysis.

2.3.1.4. Since the Operator had not provided access to all the modules of SAP pertaining to KG-DWN-98/3 Block during the earlier audit conducted in 2010-11, MoPNG stated[15] that, *the Operator would also be given necessary instructions through the Management Committee for making changes in the system configuration including configuration of Audit Information System, as desired by audit, to facilitate detailed audit*. However, Audit noted that MoPNG had not given any instructions through MC for making changes in the system configuration.

2.3.1.5. During the current audit, read only access to all the modules of SAP pertaining to KG-DWN-98/3 was requested on 14 January 2013 and subsequently reminded verbally and in writing[16] on several occasions and levels. However, till 21 September 2013, the Operator had provided restricted / customized access only.

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[14] *Supply of Subsea Equipments, Charter of FPSO, Operation & Maintenance of FPSO, EPIC of offshore facilities for development of D1-D3 field, Control Riser cum Platform, Construction of OT / Jetty / Infrastructure facilities and Hiring of Rigs.*

[15] *Audit Report No. 19 of 2011-12.*

[16] *On 31 January 2013, 22 April 2013, 25 April 2013, 25 May 2013, 4 July 2013 and 13 July 2013.*

2.3.1.6. On 21 September 2013, while agreeing that the access provided till then was restricted, the Operator stated the following:

- *In addition to restricted access they had nominated persons with SAP knowledge from different functions to run the SAP system from their individual SAP access based on the requirements of the audit.*
- *Since as a standard practice one person does not have all authorizations for all the modules, therefore, they had created additional transaction codes to provide access to inventory related transactions like consumption of material, vendor ledger and payments, Purchase orders, Outline agreement, Service entries etc.*
- *In Reliance E&P division, accounts of all domestic blocks were created in SAP under one company code (REP/5070) and configured as one system. The books for each block were inter-linked in SAP and the SAP system was integrated across company codes.*

2.3.1.7. Examination of this additional access provided revealed that the requisite access had still not been provided, as detailed below:

- Access to certain modules and components like Sales & Distribution, Project System, Assets Accounting, Bank Accounting, Audit Information System etc. was not provided.
- Some of the Transaction Codes relating to the Materials Management module and Purchasing Documents were still not functioning or had restricted access.

2.3.1.8. Nonetheless, the auditors downloaded data under the additional access provided on the domain computer of the Operator. But the auditors then found that copying of data from the domain computer provided by the Operator to DVDs or Pen Drives was not allowed and therefore, this downloaded data was of little use to Audit. Audit requested the Operator verbally and in writing on several occasions for providing the data on DVDs for analysis but considerable time was wasted and the Operator provided a DVD containing the List of PO/ Outline Agreements (OLAs) only on 31 October 2013 while DVDs containing the data pertaining to Materials Module was provided only on 11 November 2013, at the end of the audit duration.

2.3.1.9. Thus, the Operator, in spite of having information on audit schedule, gave fragmented information, that too, after a considerable delay.

2.3.1.10. The Operator in its reply to MoPNG (June 2014) and during the Exit Conference (21 July 2014) while reiterating its stance also stated the following:

a. *Contractor as a corporate entity, with a number of businesses, uses the SAP System for controlling their multiple Business Segments.*

b. *Systemic constraints due to company security and confidentiality policy naturally make it difficult to provide outsiders full access to SAP.*

c. *In spite of these constraints, all assistance was provided to the CAG's audit team with sufficient information to carry out an audit under Section 1.9 of the Accounting Procedure to the PSC.*

d. *The draft report does not mention which part(s) of the audit (if any) could not be completed as a result of restricted access to SAP or provision of "fragmented information" after "considerable delay".*

2.3.1.11. Audit had requested access to all the modules of SAP pertaining to the KG-DWN-98/3 Block for financial years 2008-09 to 2011-12 because each transaction in SAP has corresponding entries in other modules also. Audit understands the IT Security and data confidentiality concerns of the Operator.

2.3.1.12. The Operator could not provide requisite access to Audit due to the configuration of their SAP system. MoPNG had also issued audit exception (28 November 2011) stating that *"the operator should make changes in system configuration, including configuration of Audit Information System' as desired by Audit, to facilitate detailed examination".* The Operator had sufficient time (since November 2011) to configure its system in such a way so as to have a proper balance between the IT Security, data confidentiality and audit process. Further, there is a difference between 'sufficient' and 'complete / requisite' information. Information that the Operator considers to be sufficient may not be sufficient in Audit's view. Paras 2.3.1, 2.3.2 and 2.3.3 of the report clearly bring out the areas which suffered due to fragmented information after a considerable delay. Audit has been insisting on SAP access because the information provided by the Operator was found to be incomplete again and again and the Operator was also not certifying that the information provided by them was complete (Para 2.3.2). It was brought to the notice of the Operator on 13 July 2013 that the dedicated officers identified to work with Audit for accessing data / documents were either not available or did not have sufficient authorizations in the SAP system so as to run audit queries.

2.3.1.13. MoPNG in its reply (June 2014) stated that *the Audit may provide details of any specific data that audit could not get to enable issuing necessary instruction to the Contractors. Audit was also requested by DGH to quantify the Contract Cost that could not be audited, in order to consider disallowance of any such unaudited cost.*

2.3.1.14. The para clearly brings out the areas of SAP to which access was not provided. Though MoPNG notified the audit exception (28 November 2011) on this issue advising the Contractor for making changes in system configuration to facilitate detailed examination, yet no action has been taken on the audit exception either by MoPNG or by the Operator subsequent to that. It is reiterated that the Operator may be asked to configure the SAP in such a way that access to the data pertaining to the KG-DWN-98/3 block is available to audit across all modules. In this case, it is not possible to quantify the amounts due to restricted access.

2.3.2 Incomplete list of Purchase Orders (POs)

2.3.2.1. Audit uses sampling techniques for selection of cases for detailed examination. Accordingly, Audit requested the Operator on 24 December 2012 for providing a list of contracts / purchase /work orders involving money value of US$ 1 million or more. The requested list was provided by the Operator on 10 January 2013 (List 1). Subsequently, Audit again requested the Operator on 16 April 2013 for providing a year-wise list indicating the value of each contract / purchase / work / service orders issued during the years 2008-09 to 2011-12. The Operator provided (18 May 2013) List 2, generated from SAP, of the OLAs, Contracts, POs, Release Orders and Framework Orders created between 1 April 2008 and 31 March 2012 for KG-DWN-98/3 Block and for those which are common for all blocks. A comparison of these lists with the SAP line item wise details revealed some discrepancies. These deficiencies were intimated to the Operator on 17 June 2013.

2.3.2.2. Audit independently generated a list (List 4) from SAP and found that 2552 contracts were not provided by the Operator in List 2. In response the Operator stated on 27 August 2013 that they had reviewed the data and provided another updated supplementary list of POs / OLAs (List 3) and returned the List 4 with comments.

2.3.2.3. Examination of these four (4) lists revealed following other discrepancies which were pointed out to the Operator on 15 October 2013 to which Operator replied on 31 January 2014.

a) There were 14 OLAs and 166 POs above US$ 1 million in List 2 which were not provided to Audit in List 1. The Operator replied that *"the list of OLAs and POs referred to as List 1 was not based on a query in SAP, but was prepared manually by referring the hard copy of contracts and POs"*.

b) List 3 contained 269 POs and 74 OLAs which were not provided earlier. Also, there were 113 POs out of 2552 in List 4 which were not provided earlier. The Operator replied that *"List 2 was prepared from SAP using PO / contract release date range from "01.04.2008 to 31.03.2012" i.e., audit period whereas List 3 was prepared from SAP using PO / contract date created date from "01.04.2008 to 31.03.2012". All these were marked as "New included in KGD6" or "New included in common" in List 3.*"

2.3.2.4. The Operator has, thus, agreed that List 1 provided on 10 January 2013 was incomplete. List 2 provided on 18 May 2013 after a gap of 4 months was again incomplete. List 3 was provided on 27 August 2013 after a gap of 7 months. In the meantime, as already brought out in the para dealing with access to SAP, Audit had been requesting for access to SAP so that a complete list of POs /OLAs could be downloaded. The Operator provided some additional access to SAP on 4 October 2013 and Audit was able to download a list of all POs/OLAs from SAP. However, even at this point the SAP system was giving a message that the List was incomplete due to missing authorizations (screen shots in *Annexure 3*). Audit had also requested the Operator on 17 June 2013 to certify that the list of POs /OLAs provided was complete but the Operator did not do so.

2.3.2.5. On 31 January 2014, the Operator stated that the differences in the list of POs / OLAs extracted from SAP are attributable to the following:

- *"Although the audit only pertains to Block KG-D6 and a specified period, the SAP system is used across financial years and all of RIL's blocks and there are many documents which are common to different blocks and accounting periods. The results / lists of a query for extraction of data could vary based on the parameters. All purchase orders and contract numbers are generated through the SAP system and numbering occurs through the SAP system only.*
- *Further complete access of the SAP system for E&P containing plant codes for all blocks including the plant codes for common procurement and services have been provided to Audit team.*
- *It should be noted that, as RIL uses the SAP system for release of all material and service orders, accounting of all material and service receipts and processing of invoices and payments, there is no possibility of any important contract / PO escaping Audit Sampling. The Audit Team has, therefore, been provided with access to all OLAs, POs, Framework orders, and Release Orders through its access to the SAP system. The Audit Team, having been provided with complete access to the SAP system and codes for all blocks / fields, has a complete list of all OLAs, POs, Framework Orders and Release Orders".*

2.3.2.6. The contention of the Operator is not tenable because:

a. List 1, 2 and 3 were generated and provided by the Operator only. Further, the Operator had agreed that there were 112 POs out of 2552 in List 4 which were not included in earlier lists. Thus, there were three lists with Audit, but none of the lists gave assurance that the lists provided were complete.

b. Additional access of SAP system for E&P containing plant codes for all blocks including the plant codes for common procurement and services was provided to Audit team only on 4 October 2013, i.e. after a delay of over 8 months. As already stated above, the additional access was also not complete because the SAP system was giving message that the list was incomplete due to missing authorizations.

c. A complete list was requested from the Operator so that a sample of contracts could be drawn for detailed examination. The access to download list of POs /OLAs was given by the Operator on 4 October 2013, i.e. after over 8 months from the time of the request. By this time, the purpose of asking for the list, i.e., to make proper sample selection, was lost due to the delay. Further, even if SAP system is used for release of all material and service orders, accounting of all material and service receipts and processing of invoices and payments; the lists downloaded can still be incomplete due to missing authorizations.

2.3.2.7. On 11 April 2014, the Operator stated in a presentation that *"On April 1, 2010, SAP system used by the Operator migrated to a new version – Only Open Orders and inventory were migrated to the new system, resulting in difficulties in integrating the data from the two systems that overlapped during Audit period".*

2.3.2.8. The Operator in its reply to MoPNG (June 2014) while reiterating its stance also stated that *simply going by the variations in the number of Purchase Orders covered under multiple lists, Audit's assumption that the list provided to the Audit was incomplete is not acceptable. The Operator also provided assurance to Audit that all the expenditure booked to JV accounts and claimed for cost recovery were accounted through the SAP system and Audit was provided with complete data / information pertaining to the JV books including access to SAP system.*

2.3.2.9. Audit views are not based upon the number of POs as suggested by the Operator in the reply. Rather, the para speaks about the lists being incomplete because of inclusion of those POs in the subsequent lists which were not in the earlier lists proving thereby that the earlier lists were incomplete. The Operator's assurance to Audit has limited value since the access to SAP was restricted. As already stated above the SAP system was giving a message even towards the end of audit that the List of Purchase Document was incomplete due to missing authorizations (screen shots in *Annexure 3*). During the Exit Conference (21 July 2014) the Operator confirmed that *the complete list of POs/ contracts was provided to Audit.* As detailed in para 2.3.2.4 above Audit had asked for such confirmation while the field audit was on. It was not confirmed then. Now such confirmation during Exit Conference would remain unverified and, therefore, of little use in view of the position explained above.

2.3.2.10. Even towards conclusion of the audit, Audit team did not have a complete list of POs which has restricted the selection of 'samples' for detailed scrutiny. Due to this there could be some POs which may have fallen outside the 'population' and, therefore, were not picked up for detailed scrutiny in audit.

2.3.2.11. MoPNG in its reply (June 2014) stated that *Audit may report the portion of Contract Cost that is recommended for disallowance on ground of absence of payment evidence.*

2.3.2.12 Audit would like to state that the quantification of POs outside the 'population' is not possible.

2.3.3 Non-production of records

2.3.3.1. Procurement related records in respect of five POs[17] awarded between May 2008 and September 2008 amounting to INR 386.10 million related to interior decoration work at Gadimoga, Andhra Pradesh were not provided to audit. In response, the Operator stated (28 October 2013 and 15 February 2014) that they were unable to trace the tender files. The Operator in its reply to MoPNG (June 2014) stated *"Contractor has provided contract copies & invoices with supporting documents in relation to these five contracts"*. However, Audit could not verify the procurement process since the files related to the tendering were not provided.

2.4 Regulatory and control issues

The MoPNG and DGH have very specific responsibilities in their roles. MoPNG is a party to PSC. MoPNG is mandated to take measures for exploration and exploitation of petroleum resources, production, supply, distribution, marketing and pricing of petroleum and formulation of policies on these matters. DGH is responsible for regulating and overseeing upstream activities in the Petroleum & Natural Gas (P&NG) sector and to advise GoI in these areas. DGH has been entrusted with responsibilities like implementation of NELP, matters concerning PSCs, monitoring E&P activities *etc*. The effectiveness of their actions in these roles will depend upon the timely implementation of stipulated provisions and proper functioning of the monitoring mechanism. Audit, however, observed that the monitoring mechanism at MoPNG / DGH was far from being effective as it had not been able to ensure compliance with some of the PSC provisions, as discussed in detail below.

2.4.1 Delays in approval of the Work Programme and Budget (WP&B)

2.4.1.1. As per Article 5.10 and 10.11 of the PSC, the annual WP&B for Exploration / Development and Production Operations is to be submitted by the Contractor to the MC not later than 31 December each year in respect of the year immediately following. MC responsibilities are limited to review in the case of exploration operations but the responsibilities include approval in the case of development and production operations. PSC provisions also provide for submission of a revised WP&B for good cause and if the circumstances so justify for review / approval to the MC.

2.4.1.2. The timeline for submission of WP&B is clearly laid down to ensure that MC's review / approval to WP&B is completed before start of the next FY so that the work could be implemented and expenditure incurred accordingly as per the approved WP&B. The dates of submission of WP&B and approval by MC in different years where delay was noticed are summarized in Table 6**.**

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[17] *OG8/3661285, OG8/3661286, OG8/3661288, OG8/3661291 dated 28 May 2008 and OG8/3670127 dated 4 September 2008.*

Table 6 : Cases of delay in approval of WP&B

Financial Year	Due Date / Actual Date for Submission	Approval by MC	Estimates (in US$ million)	Actual Expenditure (in US$ million)	Remarks
2008-09 Budgeted Estimates (BE)	31 December 2007 / 27 February 2008 Delay of 2 months in submission	15 July 2008	4082	2749	The approval of the WP&B was after 3 ½ months of start of the FY, by which time (June end) the Operator had already incurred an expenditure of US$ 565 million.
2008-09 Revised Estimates (RE)	NA / 15 January 2009	29 May 2009	4363		The approval for the Revised Estimates was given after two months of end of the FY on the basis of actual expenditure (US$ 2749 million).
2009-10 (BE)	31 December 2008 / 15 January 2009	29 May 2009	2734	1929	BE for 2009-10 was also reviewed /approved after two months of start of the FY.
2009-10 (RE)	NA / 30 December 2009	29 November 2010	2789		MC approved RE after eight months of the end of the relevant FY.
2010-11 (BE)	31 December 2009 / 30 December 2009	29 November 2010	1039	470	BE was approved after eight months of start of the FY. By the end of the quarter ending September 2010, the Contractor had already spent US$ 344 million without MC's approval.
2010-11 (RE)	NA / 29 December 2010	7 August 2012	1215		RE was approved after more than 16 months of closure of the FY.
2011-12 (BE)	31 December 2010 / 29 December 2010	Not Approved	1547	392	BE/RE were approved together after more than four months of the end of the relevant FY. In the meantime, the Operator had already incurred an expenditure of US$ 392 million during the year without MC's approval.
2011-12 (RE)	NA / 28 December 2011	7 August 2012	563		

2.4.1.3. In some of the cases noticed, like in 2008-09 (BE), 2010-11 (BE) and 2011-12 (BE / RE) due to delays the Operator incurred expenditure before MC's approval. In other cases, the revised estimates for 2008-09 and 2009-10 were approved on the basis of actual expenditure after end of the respective financial years.

2.4.1.4. In October 2011, DGH, while examining the WP&B for 2010-11 (RE) and 2011-12 (BE), informed the Contractor that *"the Contractor has already exceeded the amount towards some of the line items approved in the FDP"* (Field Development Plan). Further, *"Contractor was time and again advised to justify the variance while examining the WP & Budget for 2011-12 (BE). However, Contractor is yet to provide the complete information with proper justifications even after lapse of about eight months and three and a half months for D1&D3 and MA fields respectively"*. Also, *"Contractor has not made any serious effort to reply to the queries raised for evaluation of the WP & Budget, thus, leading to delay in review and approval. Further, in order to justify the delay in their part, Contractor has submitted factually incorrect and inadequate information which is not acceptable"*.

2.4.1.5. From the above, it would be observed that in none of the four years the WP&B was approved before start of the FY. In Audit opinion, approval of the WP&B is a key function of the MC. 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. MC did not effectively utilize this tool. Consequently, there was inadequate budgetary / financial control over operational activities leaving the expenditure open ended.

2.4.1.6. In response to an audit observation, DGH stated (September 2013) that *"annual work programme & budget proposal related to various activities viz. Exploration, Appraisal, Development and Production having vast techno-financial implication in KG-DWN-98/3 block. Hence, it requires comprehensive analysis prior to review/approval by the Management Committee. In order to evaluate the proposal, additional information / data / clarifications are sought from the Operator; this process occasionally overshoot timeline, besides issues relating to contractual, technical aspects"*.

2.4.1.7. The Operator in its reply to MoPNG (June 2014) stated that *"the production from the block commenced in September 2008 and expenditure had to be incurred to continue production and other Petroleum Operations from the block. For all the subsequent years, the Contractor has submitted the WP&B strictly in accordance with the timelines prescribed by the PSC… Thus, the delay was due to procedural issues and a result of technical differences over executing the development plan"*.

2.4.1.8. In reply to the draft audit report, MoPNG stated (June 2014) that *PSC does not stipulate any timeline for approval by MC for the annual WP&B due to the nature of the MC's role. WP&B undergoes series of scrutiny & analysis in order to keep close control over the activities and, hence, a strict time line cannot be stipulated for MC. Lack of consensus between MC members hinders timely conclusion of the minutes of the MC meeting, though technical examination of the proposed work program and budget by MC members gets completed in time.*

Any work program not approved by MC will not be entitled for cost recovery and it is in the natural interest of the Contractor to execute the work program approved by MC. The PSC does not provide specifically for the submission of RE. The RE has been introduced for an additional level of control and the MC approves RE after reviewing the status of implementation of the budgeted work programs.

2.4.1.9. MoPNG's reply is to be viewed in light of the fact that PSC stipulation requiring submission of WP&B not later than 31 December each year in respect of the year immediately following was clearly laid down to ensure that MC's review/approval of WP&B was completed within a period of three months by 31 March, *i.e.* before start of the next financial year from 1st April. Therefore, the time taken for approval could not be stretched indefinitely. By carrying out petroleum activity and incurring expenditure before MC's approval to the WP&B, Audit opined that the control mechanism in this regard was rendered redundant.

2.4.1.10. MoPNG's contention that the PSC did not provide specifically for the submission of RE is to be viewed in light of the fact that Article 5.12 and 10.14 of PSC do provide for submission of modifications or revisions to annual WP&B to MC for review/approval, if the circumstances so justify. Therefore, RE is also required to be reviewed / approved before close of the financial year.

2.4.1.11. During the Exit Conference held with MoPNG on 11 July 2014 to discuss the draft audit report on PSCs, Secretary, MoPNG mentioned that *MoPNG had an assurance from DG, DGH that from next year onwards they would ensure that WP&B were received by 31st December and to the extent they could they would approve it by 31st March.*

Audit Recommendation 1: MoPNG / DGH may take action for timely approval of the WP&B in future.

2.4.2 Inability of DGH / MC to enforce dis-allowance of cost recovery amounting to US$ 160.81 million

2.4.2.1. Three appraisal wells were drilled by the Operator and the cost incurred was claimed by the Operator as cost recovery in the year 2010-11 as shown in Table 7.

Table 7 : Expenditure incurred on three gas wells

Sl.No.	Well Name	Total Amount of Expenditure (in US$ million)
1	AW1	17.78
2	AR1	79.50
3	AK3	60.54
Total		**157.82**[18]

[18] *This amount (US$ 157.82 million) increased further to US$ 160.81 million upto 2012-13.*

2.4.2.2. As per PSC, "Appraisal Programme" means a programme carried out following a Discovery for the purpose of appraising Discovery resulting in a proposal for Declaration of Commerciality (DoC). "Appraisal Well" means a Well drilled pursuant to an Appraisal Programme. Further, a DoC proposal is to be submitted within three years of date of notification of discovery after carrying out the appraisal within the MC reviewed appraisal area. However, wells AR1 and AW1 were drilled post-submission of DoC proposal of D29, D30, D31 and D34 discoveries. Well AK3 was drilled outside the MC reviewed appraisal area. Thus, the drilling of these three wells was without the approval of the MC.

2.4.2.3. Consequently, as per PSC terms, the expenditure incurred on account of these wells was not eligible for cost recovery, and therefore, DGH disallowed the cost recovery of wells AR1, AW1 and AK3 vide its letter dated 3 June 2010. Further, MC in its meeting held on 7 August 2012 disallowed the cost. The Operator, however, did not accept the disallowance and requested (August 2012 and February 2013) MoPNG / DGH to cover the locations AW1 and AR1 under Rig Moratorium Policy[19]. DGH in its reply to Audit (September 2012) stated that the cost of three wells has been disallowed and has been communicated to MoPNG. In September 2013, MoPNG intimated to the Operator that the cumulative costs for these three wells amounting to US$ 160.81 million is disallowed from computation of Cost Petroleum entitlement.

2.4.2.4. Despite the fact that cost recovery was denied by the DGH and MC, Audit noted that the Operator included the cost of these wells for cost recovery in the books of accounts for the year ended 2011, 2012 and 2013. 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 has been unable to enforce its decision.

2.4.2.5. The Operator in its reply to MoPNG (June 2014) stated that *the drilling of three wells was a technical requirement for appraisal of the discoveries.* The Operator argued that *"It may also be noted that Article 6.5(c) of the PSC provides that the MC has only 'advisory function' in relation to the Contractor's 'proposal for an Appraisal Programme or revisions or additions thereto' ".*

2.4.2.6. In Audit opinion, the Operator's reply is not in consonance with the PSC contractual provisions as the expenditure incurred did not follow the laid down procedure. The findings of the appraisal programme result in a DoC. Two of these wells were drilled post submission of DoC to further appraise the same discoveries, which implies that the timelines are not sacrosanct and also that the DoC proposal was not comprehensive. As

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[19] Due to non-availability of deepwater rigs, committed work programmes were adversely affected. Consequently, MoPNG (19.7.2010) gave approval for granting of Rig Holiday in Deepwater Blocks, i.e. a drilling moratorium. This drilling moratorium was for a period of 3 years w.e.f. 1 January, 2008 to 31 December 2010. DGH was to regularly monitor availability/tie-up of the rigs in close coordination with the Contractors with respect to an agreed milestone so that the drilling commitments are completed within the respective exploration phases after grant of rig moratorium.

regards the fact that MC has only advisory function, it is pertinent to note that while MC may have only advisory function in respect of the appraisal programme, it has approval function for any expenditure incurred thereof.

2.4.2.7. MoPNG, while accepting the disallowance of the cost of these wells stated (June 2014) that, *"The mode of recovering the amount is being evaluated by the MoPNG taking into consideration the pending arbitration proceeding on issues which constitute the major component of Profit Petroleum to be recovered".*

2.4.2.8. Though the DGH disallowed the amount in 2010, a final decision was not taken by MoPNG till 2013. Now, in 2014, MoPNG is re-evaluating the 'mode of recovery'. In Audit opinion, this underlines the fact that the enforcement of the disallowance was delayed.

2.4.2.9. During the Exit Conference (July 2014), MoPNG intimated that *M/s CPCL and M/s GAIL have been directed (July 2014) to remit the sale proceeds of Crude oil / Condensate / Natural gas from KG-DWN-98/3 Block into the Government account so as to recover the amount*.

Audit Recommendation 2: MoPNG may ensure that the disallowed cost of three wells amounting to US$ 160.81 million is recovered.

2.5 Issues in approvals for petroleum operations

2.5.1 Exploration, appraisal and relinquishment

2.5.1.1. In Audit Report No. 19 of 2011-12, C&AG had pointed out that, contrary to PSC provisions[20], the Contractor was allowed to enter the second and third Exploration Phases[21] without relinquishing 25 *per cent* each of the total Contract Area[22] and to retain the entire Contract Area by treating it as 'discovery area' at the end of Phase I and Phase II. Such retention was allowed by the MC in July 2006 and later by MoPNG in July 2008[23].

2.5.1.2. Accordingly, Audit recommended that the MoPNG should review determination of the entire Contract Area of KG-DWN-98/3 as 'discovery area' strictly in terms of the PSC provisions and delineate the stipulated 25 *per cent* relinquishment area at the time of the conclusion of the 1st and 2nd exploratory phases, and then correctly delineate the 'discovery area', linked to well or wells drilled in that part, without considering any subsequent discoveries (which are invalid on account of non-compliance with PSC provisions).

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[20] *Article 4.1 and 4.2 the PSC.*

[21] *Exploration Phase I started on 7th June 2000 which lasted for four years (including extension period) upto 6 June 2004 and the Contractor opted to enter Exploration Phase II as per Article 3.5 of the PSC beginning 7 June 2004. Exercising the option to enter into the next phase of exploration at the end of Phase II (6 June 2005), the Contractor entered Exploration Phase III on 7 June 2005 which ended on 6 June 2007 (extended upto 15 July 2008).*

[22] *Contract Area was of 7645 sq. km.*

[23] *Decision was conveyed by MoPNG vide letter dated 24 February 2009.*

2.5.1.3. After deliberation, in October 2013, MoPNG issued an order for immediate relinquishment of 6198.88 sq. km. out of the total 7645 sq.km., allowing the Contractor to retain 1148.12 sq. km. relating to the Petroleum Mining Lease (PML) area in respect of four gas / oil fields[24]. The October 2013 order also mentioned that in respect of three other discoveries, i.e. D 29, 30 and 31, the matter was being considered separately and the GoI reserved the right to take any further action as deemed fit. However, the Contractor was allowed to retain 298 sq. km. under tentative Petroleum Exploration Licence (PEL) pertaining to these three discoveries.

2.5.1.4. Review of the action taken in response to the Audit recommendation revealed the following:

2.5.1.4.1. MoPNG had not reviewed the determination of the entire contract area as 'discovery area' strictly in terms of Articles 4.1 and 4.2 at the end of first and second Exploration Phase. Instead, the decision regarding relinquishment had been taken on the basis of Article 3.11 of the PSC, which states that *"if at the expiry of the exploration period a plan for development of a commercial discovery is under consideration by the Management Committee or an application for a lease is under consideration by Government pursuant to Articles 10.11 and 21 respectively, this contract and the license shall continue in force with respect to that part of the contract area to which the application for the lease relates, pending a decision on the proposed development plan and the application for the lease, but shall cease to be in force and effect with respect to the remainder of the contract area*".

2.5.1.4.2. In Audit view, MoPNG / DGH had taken the decision under Article 3.11 after considering the status of all the 19 discoveries made in the Block till the end of Exploration Phase III instead of delineating the stipulated 25 *per cent* relinquishment area at the time of the conclusion of Exploration Phases I and II in June 2004 and June 2005, as recommended in the previous audit report.

2.5.1.4.3. It may be noted that the Audit contention that the entire contract area was not a discovery area at the end of first and second phases and the related Audit recommendation were further supported by the fact that in July 2007, the Contractor, while submitting the Appraisal Programme for D29, 30, 31 and 34, had demarcated the entire area of 7645 sq. km. indicating separate discovery/appraisal and development areas for the discoveries made as on that date upto D 34 discovery (Table 8).

Table 8 : Area as demarcated by the Operator in July 2007

Demarcated Area corresponding to discoveries	Area in sq. km.
Development Area for D1 D3 discoveries, which were notified in October 2002	339
Appraisal Area for satellite discoveries (D 4, 6, 7, 8, 16, 19, 22 and 23), which were notified between January 2003 and October 2005	1729

[24] *(D1 & D3), (D-26), (D-34) and (D-2, 16, 19 & 22).*

Discovery Area for D 26 discovery, which was notified in June 2006	132
Discovery Area for the appraisal programme for 4 discoveries (D 29, 30, 31 and 34, which were notified between February and May 2007)	5445
Total area	**7645**

2.5.1.4.4. Table 8 above summarizing the status of block as on July 2007 shows that only 2200 (339 + 1729 + 132) sq. km., i.e. 29 *per cent* of the entire contract area (of 7645 sq. km.), was discovery/appraisal and development area even upto the period of notification of D 26 discovery, i.e. June 2006. The major part of the contract area, i.e. 5445 sq. km. (corresponding to the four discoveries viz. D29, D30, D 31 and D34) was identified by the Contractor as 'discovery area' only in July 2007**.** Therefore, this vindicated Audit's view that entire contract area was **not** a discovery area at the end of 1st and 2nd exploration phase in June 2004 and June 2005.

2.5.1.4.5. Apparently, the Contractor could have done this demarcation corresponding to the discovery area from the first discovery onwards. In turn, the MoPNG could also have utilised this information to implement the audit recommendation.

2.5.1.4.6. However, based on the Contractor's claim regarding the entire block area as discovery area *(which is incorrect, as detailed in the C&AG Report No. 19 of 2011-12*), the MC accepted that the entire Block area was a discovery area in July 2006. Further, MoPNG approved, on 31 July 2008[25], acceptance of the entire contract area of the KG-DWN-98/3 Block as discovery area subject to the following:

a) *The operator may be allowed retention of entire contract area of the block KG-DWN-98/3 as discovery area in the 2nd and 3rd exploration phase.*

b) *The timeline for appraisal of the Discoveries may be reckoned from 11th July 2006.*

c) *Since the entire Block area was accepted as the Discovery Area, the Block Area, therefore, must be appraised within time frame of three (3) years, commencing from the above date.*

d) *Other terms and conditions of the PSC would remain unchanged.*

2.5.1.4.7. Therefore, in terms of the MoPNG's decision, after completion of the appraisal work on the basis of an MC reviewed appraisal programme in the 'discovery area', the Contractor was required only to prepare development plans for the identified development areas and relinquish the balance area without delay within the PSC-stipulated timelines.

2.5.1.4.8. Audit, however, noted that MoPNG / DGH did not insist that the Contractor adhere to the conditions set forth in its approval and carry out only appraisal activities. In fact, Audit found that DGH, the technical arm of the MoPNG, itself opined (March 2009) that parts of the MoPNG decision relating to points at serial no. b) and c) above were not

[25] *Decision was conveyed by MoPNG vide letter dated 24 February 2009.*

implementable. DGH wrote to the MoPNG stating that the appraisal of the entire block would be difficult to implement since 'discovery area' was not confined to any particular discovery while the appraisal programme is related specifically to a particular discovery. In this regard, Audit noted that the DGH interpretation regarding 'discovery area' was not in line with PSC provisions[26] according to which "*discovery area means that part of the contract area about which based upon discovery and the results obtained from a well or wells drilled in such part.....*" thereby clearly implying that a discovery area will correspond to a particular discovery and also as per the position elaborated in the paras 2.5.1.4.3 and 2.5.1.4.4 above.

2.5.1.4.9. In the background of the MoPNG decision and its non-enforcement, Audit re-visited the extant PSC provisions regarding exploration and appraisal. It may be noted that

- PSC provides for step-wise development of a discovery and the related discovery/ development area.
- If, pursuant to Article 10.1 (c), the Contractor notifies the MC that the discovery is of potential commercial interest, the Contractor shall prepare and submit to the MC within 120 days[27] of such notification, a proposed appraisal programme with a WP&B to carry out an adequate and effective appraisal of such discovery designed to achieve both the following objectives: (i) determine without delay, and, in any event, within the period specified in Article 10.5, whether such discovery is a commercial discovery and (ii) determine, with reasonable precision, the boundaries of the area to be delineated as the development area; Thereafter, the next stage is submission of DoC proposal (after completion of appraisal in the discovery/appraisal area as per MC reviewed appraisal programme) under Article 21.5.4 within three years[28] of notification of the discovery.
- If no DoC proposal is submitted to the MC by the Contractor within the three years' period, then the Contractor should relinquish its rights to develop such discovery and the area relating to such discovery should be excluded from the contract area.
- The DoC is followed by submission of development plan under Article 21.5.6. Once the DoC is reviewed by MC and the development plan is approved, that part of the discovery area covered by the development plan is treated as development area. Therefore, the remaining area should be relinquished.

2.5.1.4.10. In case the Contractor does not relinquish the area and continues with exploration activities in such area then, contrary to the intent of the NELP[29], this would result

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[26] *PSC provision 1.39.*

[27] *120 days in respect of oil and 1 year in respect of gas discoveries.*

[28] *30 months in respect of oil discovery and 3 years in respect of gas discovery.*

[29] *The key feature of the NELP PSCs is that the Contractors bid on the percentage of the reward that the GoI receives from the hydrocarbon block. The Contractor undertakes the initial exploration risks. If no hydrocarbons are discovered, or the quantities are small, the revenues generated may not be sufficient to recover the costs incurred; this risk is borne by the Contractor.*

in GoI sharing the exploration risk, especially where there have been significant commercial discoveries in the initial exploration period. This would also delay subsequent recycling of the balance area where re-bidding can take place.

2.5.1.4.11. Audit had observed in Audit Report No. 19 of 2011-12, that *"DGH and MoPNG chose to go along with differing interpretations of the operator concurrently – to continue with exploration activities, side by side with declaration of the entire contract area as discovery area*".

2.5.1.4.12. Thus, PSC provisions as above, MC acceptance of discovery area in July 2006 and MoPNG decision of July 2008[30] mean that no further exploration activity except the appraisal activities relating to the discoveries made till July 2006 needed to be undertaken in the entire discovery area of 7645 sq. km. In the case of KG-DWN-98/3, the Contractor was able to do further exploration activities in the 'discovery area', which included drilling of eight[31] exploration wells and six[32] appraisal wells of discoveries[33] resulting from these exploration wells (*Annexure 4*).

2.5.1.4.13. Therefore, non-enforcement of MoPNG decision led to continuation of exploration activities in the discovery area at an expenditure of US$ 427.03 million at the risk of revenue of the commercial discoveries, viz. D1 and D3, made in the Block.

2.5.1.4.14. The Operator in its reply to MoPNG (June 2014) stated as under:

The understanding of the auditors.... with regard to the definition and meaning of terms such as "discovery area", "relinquishment" and "appraisal" within the PSC was deeply flawed and had no basis as per the provisions therein....The limited purpose of Discovery Area under the PSC is only for determination of the area to be retained by the Contractor in the subsequent exploration phases for further exploration. Discovery Area is not determined for conducting appraisal activities as the PSC intends appraisal of a Particular Discovery.

Activities of exploration and appraisal continue through the life of even a producing field after the development phase.

The area was retained strictly as per the provisions of the PSC and with the approval of the MC and Government and the work resulted in discovering more reserves for the benefit of the Parties to the PSC and the nation.

2.5.1.4.15. Audit's views regarding the discovery area and relinquishment are supported by PSC provisions. Therefore, Operator's assertion regarding the understanding of the auditors does not have merit. The status of the discovery/appraisal and development area

[30] *Conveyed by MoPNG vide letter dated 24 February 2009.*

[31] *MG1, MB1, AA1, Q1, P2, R1, MK1, and L1.*

[32] *BA1, AS1, AR2, BA2, AV1 and AB1.*

[33] *D29, 30, 31 and 34.*

(Table 8 above refers) given by the Contractor to DGH in July 2007 itself corroborates Audit view that the entire contract area was not a discovery area at the end of first and second exploration phase.

2.5.1.4.16. Besides relinquishment, delineation of the discovery area also serves to indicate the area for ascertaining commerciality and carving out development area in future. Further, Operator's contention that discovery area is not determined for conducting appraisal activities as the PSC intends appraisal of a particular discovery is contradictory in view of the fact that the Operator himself had proposed a discovery area of 5445 sq. km. corresponding to the four discoveries viz. D29, D30, D31 and D34 for appraisal programme (for 36 months) in order to ascertain the commerciality.

2.5.1.4.17. Operator's contention that activities of exploration and appraisal continue even after the development phase is not supported by extant PSC provisions.

2.5.1.4.18. As already discussed above, the approval of the MC and MoPNG was not in line with the PSC provisions. As regards the potential benefits which may accrue to stake holders, Audit would like to state that its views are not meant to hamper exploration but that such activities should be conducted within the contractual regime and legal framework.

2.5.1.4.19. In reply (June 2014), MoPNG stated as under:

- *Article 4 of PSC deals with the Contractor's right to retain and relinquish the Contract Area in phases and it permits the retention of the 'discovery area' by the Contractor at the end of phase I and II exploration phases for further exploration and appraisal operations. Article 3.11 deals with retention of portions of Contract Area beyond the exploration phases on account of development operations. MOP&NG applied appropriate PSC provisions as deemed fit as per the nature of the decision taken.*
- *The CAG's different view on this technical issue of discovery area has been placed before the Public Accounts Committee, where both the sides have presented their views and counter views. Pending a recommendation of PAC to the contrary, the CAG's opinion on the technical issue does not override the determination done by Government.*
- *There has been no decision in MOP&NG to amend the provisions of PSC to disallow exploration in phase II and III and waiving the Contractor's liability to complete committed minimum work program, which are exploratory in nature. Audit appears to have mis-interpreted the MOP&NG letter to the effect of amending the PSC.*
- *With regard to audit comments on GoI's share of exploration risk, it is clarified that the Government does not share any risk in the functioning of PSC and Government earns only a share in profit and royalty on production. Audit's interpretation that Government shares the exploration risk will have the consequence of increasing the liability of Government, which is not intended in the PSC.*

- *Records do not show that any exploration other than appraisal was done after 15 July 2008. Article 4 permits the Contractor to retain discovery area in phase II and phase III for further exploration in such discovery area. After entering into phase II or phase III, the Contractor is liable under Article 3 of PSC to carry out exploration and complete at least the committed minimum work program stipulated in Article 5.3 and 5.4. The Contractor's liability to complete committed minimum work program is not waived even if the discovery area of 1st discovery extends to the entire Contract Area.*
- *Audit's interpretations would unduly benefit the contractors to avoid their liabilities to carry out exploration operations during the exploration phases and to complete committed minimum work program under different phases of exploration.*
- *Conclusion that 'MOP&NG decision' of February 2009 was not enforced is incorrect as the exploration phase itself was over in July 2008 i.e. much before the stated 'MOP&NG decision'.*
- *Audit would need to clarify if discoveries made in phase II and phase III are to be disallowed as suggested by CAG (paragraph 2.5.1.2 of draft report), and as to how MA-26 discovered in phase II, which has been under production for 5 years and D-34 discovered in phase III, whose development plan has already been approved by MC, should be treated under the PSC as per the interpretation of CAG.*

2.5.1.4.20. Audit's views on MoPNG's response are as under:

- MoPNG's decision regarding the relinquishment of the area under Article 3.11 now (October 2013) would have been appropriate if MoPNG had taken the decision after reviewing determination of the entire contract area of KG-DWN-98/3 as 'discovery area', strictly in terms of the PSC provisions and delineated the stipulated 25 *per cent* relinquishment area each at the time of the conclusion of the 1st and 2nd exploratory phases in June 2004 and June 2005, and then correctly delineated the 'discovery area' strictly based on the PSC definition, linked to well or wells drilled in that part. Therefore, the permission granted to hold the entire Contract Area as discovery area in the subsequent exploration phases without the stipulated relinquishment was not strictly in accordance with the provisions of the PSC, as claimed by MoPNG.
- Regarding PAC's recommendation on the matter being pending, it is clarified that this being a follow up, Audit has brought out the current position in this regard.
- Audit had not interpreted MOPNG's letter to have an effect of amending the PSC provisions, as claimed by MoPNG but highlighted the deficiency regarding non-implementation of its decision of July 2008 (conveyed in February 2009) and the PSC provisions relating to completion of appraisal, submission of DoC (by July 2009) and development plan and thereafter relinquishment of the remaining area not covered under the development area within the PSC stipulated timelines.
    - However, Article 3.5 (b) already allows the Contractor to avoid further obligation in respect of the minimum work program under Article 4 for any

subsequent exploration phase if, at the end of 1st or 2nd exploration phase, the contractor opts not to proceed to the next exploration phase by retaining only discovery and development areas.

- While reiterating that the delineation of the entire contract area as discovery area was incorrect, Audit would like to state that its interpretation is not towards helping contractors to avoid the minimum work programme obligations but rather to achieve the objective of PSC to efficiently monetize petroleum resources in an expeditious manner. This is because:

  a. Exploration phase includes both exploration and appraisal operations;

  b. On declaring a discovery the Contractor is obliged to move ahead to appraise and submit DoC /development plan within the PSC stipulated timelines;

  c. As detailed in para 2.5.1.4.9 above, if, pursuant to Article 10.1 (c), the Contractor notifies the MC that the discovery is of potential commercial interest, the Contractor is required to follow the next steps for development of the discovery and the discovery/ development area.

  d. Article 21.5.1 read with Article 4.4 clearly says that notwithstanding the provisions of Article 3, the Contractor shall be entitled to retain the discovery area subject to the provisions of Article 21 – this Article provides for stage-wise development of a discovery and the corresponding discovery/development area.

2.5.1.4.21. Therefore, MoPNG's own decision of July 2008 / February 2009 mentioning that since the entire block area was accepted as discovery area, the Block area, therefore, must be appraised within three years, substantiates Audit view that PSC provides for stage wise development of petroleum reserves wherein subsequent to declaring a discovery the Contractor is obliged to move ahead to appraise the discovery within the discovery area and submit DoC / development plans and after any development area has been designated, relinquish all of the contract area not included within the said development area.

- Audit understands that no exploration other than appraisal was done after the third exploration phase i.e. 15 July 2008. However, Audit has only pointed out the deficiency regarding allowing the exploration activities in the discovery area after July 2006 at the risk of revenue of KG-DWN-98/3 block.

- As regards MoPNG's reply regarding Audit's views given in paragraph 2.5.1.2 of the draft report, the anomalous situation arose only because of non-enforcement of the PSC provisions relating to relinquishment at an appropriate time by MC/MoPNG. Incidentally, in this report Audit has only commented upon the exploration activities subsequent to July 2006 which does not include the MA-26 discovery. However, as was clarified in the Exit Conference with the MoPNG representatives on 11 July 2014 the main point being highlighted in this regard was that since MoPNG had decided in

July 2008 / February 2009 that the entire area was a discovery area from July 2006, the same was to be appraised upto July 2009 whereas the Contractor had done exploration activities also in the discovery area after July 2006.

- Audit is not against exploration per se. Initially the exploration risk is that of the Contractor until there is a commercial discovery. After a commercial discovery the exploration risk is shared between the Contractor and the GoI if exploration is carried out in the unexplored / undiscovered contract area as per the PSC provisions.
- However, in this case the exploration was carried out in the discovery area which was supposed to be only appraised within a time frame. Therefore, GoI was unduly made to share the exploration risk through the revenues from the existing commercial discoveries of the Block.

2.5.1.4.22. Thus, in view of the PSC provisions as discussed above, MC acceptance of discovery area in July 2006 and MoPNG decision of July 2008[34], Audit is of the opinion that further exploration activities in the 'discovery area' (which included drilling of eight[35] exploration wells and six[36] appraisal wells of discoveries[37] 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.

Audit Recommendation 3: Under such a scenario, 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.

2.5.2 Proposal for Declaration of Commerciality (DoC)

2.5.2.1. As required under Article 10.5 and 21.5.4 of the PSC, the Operator submitted (February 2010) a DoC proposal for D29, D30, D31 and D34 discoveries for MC review.

2.5.2.2. Evaluation of DoC is a technical-cum-economic analysis based on relevant technical and economic data including estimated recoverable reserves, sustainable production

[34] *Conveyed by MoPNG vide letter dated 24 February 2009.*

[35] *MG1, MB1, AA1, Q1, P2, R1, MK1, and L1.*

[36] *BA1, AS1, AR2, BA2, AV1 and AB1.*

[37] *D29, 30, 31 and 34.*

levels, estimated development and production expenditures, prevailing and forecasted prices, and other pertinent technical and economic factors according to Good International Petroleum Industry Practices as well as all evaluations, interpretations and analyses of such data and feasibility studies relating to the Discovery prepared by or for the Contractor.

2.5.2.3. While appraising the proposal, DGH and the Operator deliberated on various issues including clarifications on reservoir, production and finance / techno-economics. DGH insisted on ascertainment of production profile of the discoveries. It observed that Modular Dynamic Test (MDT) carried out by the Operator did not provide individual well testing rates in order to ascertain sustainable production levels which was necessary for evaluation of commerciality of discoveries. In fact, for the requirement of well test data / rate, the Operator himself admitted that *"derivation of permeability based on MDT is not reliable"*. The MDT data acquired by the Operator only had reservoir pressures and types of fluid encountered. As no appraisal wells were drilled in the pools of discovery wells to substantiate the production rates considered by the Operator in the DoC, DGH felt that the profile generated without considering MDT / Drill Stem Test (DST) data in the wells was not on a sound technical basis. Hence, DGH observed that in the absence of a reliable production profile, economic analysis could not be carried out. Also, while clarifying on the economic viability issue raised by DGH, the Operator stated in a letter to DGH on 4 June 2010 that "*There is no doubt that the development of these discoveries, which are marginal in nature, ... is not viable at US$ 4.2 / mmbtu"*.

2.5.2.4. Since the DoC did not provide individual testing rates and could not demonstrate sustainable production levels, in October 2010, DGH communicated to the Operator that the DoC for the four gas discoveries could not be reviewed. Subsequently, in November 2010, the Operator submitted additional test data/information. However, this data related only to the D34 gas discovery. Finally, in November 2011, based on the test data and subsequent meetings and correspondence, MC reviewed the DoC proposal for D34 discovery but in respect of D29, D30 and D31, MC re-iterated DGH views and stated that *"in the absence of production tests which provide sustainable production levels from the reservoir, commerciality of discoveries D29, D30 and D31 could not be evaluated.*"

2.5.2.5. In May 2012, while issuing a notice for MC meeting, the Operator requested the MC to complete review of DoC for D29, D30 and D31. Thereafter, in a subsequent MC meeting (August 2012), MC advised the Operator to generate and submit test data for these discoveries. Subsequently, the Operator submitted a proposal on 6 October 2012 and 21 November 2012 to undertake test (DST) in only one well out of the three discoveries. The Operator further said that such results of DST for one well should be applicable to other two wells also. While DGH agreed to the Operator's proposal to undertake DST in one discovery well, they further asked the Operator on 27 November 2012 to submit a plan for surface flow test for the other two discovery wells also.

2.5.2.6. After considerable assessment, correspondence and clarifications, the DGH came to a conclusion that the DoC in respect of these three discoveries was not acceptable. The Operator insisted upon re-opening the issue and submitted a proposal for DST. Yet, the Operator did not carry out the same and later argued that, as per PSC, (a) the DST was not mandatory, (b) Contractor has the right to determine requirement for DST based on its technical judgment, and (c) it was not the only test. Audit scrutiny in this regard disclosed the following:

- Initially, no production test data for the three discoveries was provided by the Operator subsequent to the August 2012 MC meeting.
- Later, the DST, as proposed by the Operator itself for one well, was not undertaken. Even as of February 2014, it has not been undertaken.
- In this context, it may be noted that as per PSC provisions, while reviewing the DoC, MC might request any other additional information it might reasonably require so as to complete the review of the proposal made by the Contractor. The PSC permitted time-line for review of DoC expired in August 2010 but since the Operator re-opened the issue, it was bound to supply any such clarification as is required. Therefore, the Operator could not have rejected the demand.
- As of June 2014, review of the DoC of these three discoveries had not been completed by MC.

2.5.2.7. On 15 April 2013, DGH had, while submitting the proposal for relinquishment of the contract area to MoPNG, also proposed that the area pertaining to these three discoveries be relinquished. In its proposal, DGH had re-iterated that no production test data for these discoveries had been provided by the Operator till that date. Further, DGH mentioned that since surface flow test was a PSC requirement, the DoC could not be reviewed by the MC. Moreover, the Operator could not keep a part of the contract area for an indefinitely long period in the garb of an incomplete DoC proposal. The time limit for submitting a valid DoC for those three discoveries was already over[38].

2.5.2.8. Subsequently, after examination of the case in MoPNG and holding of deliberations with DGH and Contractor, the relinquishment proposal was submitted by Secretary, MoPNG on 30 August 2013 to Minister, PNG proposing for relinquishment of area related to D29, D30 and D31. Finally, in October 2013, while deliberating on the proposal for relinquishment, the Minister (PNG) observed (with respect to D29, D30 and D31 discoveries) that *"there is a clear cut difference of opinion between the Contractor and the DGH as to whether DST is a mandatory requirement under the PSC or not. It is difficult to rule out either of these interpretations…………a fair and balanced approach could be to allow the Contractor to conduct DST now and review the DoC on the basis of outcome of*

[38] *Under Article 21.5.4 of PSC, a proposal for DoC is required to be submitted within 3 years from the discovery.*

these tests. Depending on the outcome, the matter may be taken up before CCEA (Cabinet Committee on Economic Affairs) *for its information fully explaining the facts and circumstances of the case".*

2.5.2.9. Thus, in October 2013, while issuing the order regarding relinquishment of Contract Area of KG-DWN-98/3 Block, MoPNG allowed the Contractor to retain 298 sq. km. contract area for D29, D30 and D31 discoveries under a tentative PEL as the matter was being considered separately by the GoI.

2.5.2.10. Audit noted that this decision was in contravention of DGH technical advice and would have significant financial impact as the activity and budget of DST for the three discoveries had been included (December 2013) by the Operator at an approximate total cost of US$ 100 million in the WP&B for FY 2013-14 (RE) and 2014-15 (BE). The Operator also sought (10 January 2014) DGH approval of time for DST. In turn, DGH addressed the issue to MoPNG. Final decision had not been taken, as of February 2014, on the issue of whether the cost of DST was recoverable or not under extant PSC provisions. As of February 2014, the case had not been submitted to CCEA.

2.5.2.11. In Audit view, there has been inordinate delay in finalising the review of the DoC proposal in respect of these discoveries, which is against NELP objective of expeditious monetisation of hydrocarbon resources.

2.5.2.12. The Operator in its reply to MoPNG (June 2014) stated that *"the contention of DGH that DST is mandatory because it is mentioned in the definition leads one to the obviously absurd conclusion that the Contractor cannot even notify a discovery without conducting a DST".*

2.5.2.13. In this regard, Audit would like to state that Article 10.5 of PSC states that *"the Contractor shall in respect of a Discovery of Crude Oil advise the Management Committee by notice in writing .... whether such Discovery should be declared a Commercial Discovery or not. Such notice shall be accompanied by a report on the Discovery setting forth at relevant technical and economic data including* ***estimated recoverable reserves, sustainable production levels****, estimated development and production expenditures, prevailing and forecasted prices, and other pertinent technical and economic factors according to Good International Petroleum Industry Practices as well as all evaluations, interpretations and analyses of such data and feasibility studies relating to the Discovery prepared by or for the Contractor, with respect to the Discovery and any other relevant information*".

Further, Article 10.2 mentions that *"If the Contractor determines to conduct a drill stem or production test, in open hole or through perforated casing, with regard to the Discovery, it shall notify the Government....".*

2.5.2.14. Thus, the issue is not of DST but that the Operator should be able to show adequate evidence of 'sustainable production levels' in whatever way agreed. The optional nature of DST is not being debated here. The Operator was not able to do so to the satisfaction of MC / DGH due to which in May 2010, DGH, in their letter to the Operator, asked the Operator, *"to provide the details of estimation of production rates arrived at through MDT data"*. Since the Operator was unable to provide the requisite data to MC / DGH, DGH while intimating (October 2010) the Contractor that the DoC for the four gas discoveries could not be reviewed, had mentioned that *"the profile generated without generating/considering MDT/DST data in the wells may not be of sound technical basis*". Further, DGH had also mentioned that *"As per the Article 10.5 of PSC the operator, is required to generate and provide data pertaining to "**sustainable production levels',** which is essential for generating the production profile. Such data was not acquired by the operator in any of the wells under consideration. Hence, the production profile in the DOC could not be evaluated, due to lack of production testing data"*.

2.5.2.15. In response (June 2014), MoPNG stated that *this was a case where DGH had not considered the testing methods adopted by the Contractor. As the Contractor had appealed time and again to MOP&NG against the decision of DGH, the MOP&NG was deliberating the issue for resolving the issue in a way that would enhance energy security without compromising the technical requirements of PSC. Time taken to settle the dispute should not be treated as delay*.

2.5.2.16. MoPNG's reply may be viewed in light of the fact that, as per the PSC provisions, the review of the DoC was to be completed by MC by August 2010. However, 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 been not finalised as yet.

2.5.2.17. During the Exit Conference held with MoPNG/DGH on 11 July 2014 to discuss the draft report, Secretary, MoPNG informed that MoPNG hoped to get a decision on this issue soon.

Audit Recommendation 4: MoPNG may develop consistent and uniform parameters for evaluating commerciality of discoveries.

2.6 Production from D1-D3 gas fields

2.6.1 Introduction

2.6.1.1. The process of discovery, development and production is described in Article 10 of the PSC which, *inter alia*, contains details of data and supporting information besides the time limits for approval that should accompany or be mentioned in the Comprehensive Development Plan.

2.6.1.2. The Operator made 19 discoveries in the Block between 2002 and 2008, out of which 18 are gas discoveries, and one is an oil discovery. Of the 18 gas discoveries, D1 and D3, which were discovered in October 2002, were declared by the Operator as commercial discoveries in April 2003 and March 2004 respectively, after taking the advice of the MC.

2.6.1.3. After notification of D1 and D3 gas discoveries as commercial discoveries, the Operator submitted (May 2004) an Initial Development Plan (IDP) to DGH for approval of the development of discoveries by MC as required under Article 21.5.6 of the PSC, in the delineated area of 339.41 sq. km. (4.4 *per cent* of the total block area). IDP targeted only a portion of two channel complexes in the reservoir, i.e. Channel A (D1) and Channel B (D3), where exploratory wells[39] were drilled.

2.6.2 Gas estimates

Audit examined the events leading to estimates of the recoverable reserves as in the development plans as follows:

2.6.2.1. At the time of submission of the IDP, the Operator had estimated the original gas-in-place (OGIP) with confidence based on the studies done and validation by various international experts. The Operator had, in fact, given assurance by stating that while, "*future studies of the D1-D3 gas fields connectivity would have a better characterization of overbanks and levees (the thin bed sands)…*" but with respect to the initial wells in the vicinity of A1, the Operator affirmed that *"these areas have been adequately characterized to predict its behavior with a fair degree of confidence. Therefore, any future studies would not impact the result of the initial wells and the field performance. Rather it would enhance understanding to develop a better depletion strategy.*''

2.6.2.2. In response to a query from DGH seeking details of reservoir estimation, the Operator informed (October 2004) that in view of variations in estimation techniques and subjective judgments involved at various stages of estimation, the reserves were got estimated by two agencies (third party) of international repute. The Operator had stated (May 2004) in the IDP that due to complexity of the reservoir and associated uncertainties, various agencies *viz.* DeGolyer & McNaughton, Petroleum GeoSystems and Petrotel were engaged to estimate the OGIP. DGH, after reviewing the IDP and the submissions of the Operator, evaluated OIGP of 5.45 tcf[40] considering 100 *per cent* of P1 and 50 *per cent* of P2 and recoverable reserves of 3.81 tcf.

2.6.2.3. The MC approved the IDP on 5 November 2004. However, before start of commercial production, the Operator submitted (October 2006) Addendum to IDP (AIDP) for the development of D1-D3 gas fields. The Operator, while submitting AIDP, stated that the IDP had been based on information of four wells. Drilling of two development wells[41] helped in better understanding of overall hydrocarbon potential of the Block in general and upgradation of reserves associated with D1-D3 gas discoveries in particular. Also subsequent to the approval of IDP, lot of work had been done to assess the overall hydrocarbon potential

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[39] *A1, A2A, B1 and B2.*

[40] *Trillion Cubic Feet.*

[41] *A10 & B7.*

of the Block including D1-D3 gas fields. As a result, the hydrocarbon potential of the Block and recoverable reserves in D1-D3 gas fields had increased considerably.

2.6.2.4. Consequently, the AIDP estimated increased OGIP of 14.164 tcf and recoverable reserves of 12.04 tcf. The MC, after reviewing the submission of the Operator, approved AIDP (12 December 2006) with OGIP of 12.587 tcf and recoverable reserves of 10.03 tcf.

2.6.2.5. Incidentally, AIDP was based on data from a small portion of the A and B channels only. No wells were drilled in the layered reservoir area on the basis of which the reserves estimate in the AIDP was increased. However, DGH did not ask the Contractor for conducting appraisal in these areas. Audit has already commented upon the lack of a formal appraisal programme in its earlier Report No.19 of 2011-12. At that time, DGH, MoPNG and Operator had defended their actions on the ground that while a formal appraisal programme was not submitted, appraisal activities, which fulfilled the objectives of PSC, were carried out.

2.6.2.6. The Operator in its reply to MoPNG (June 2014) stated that *"the AIDP was based on study and validation by internationally reputed agencies"*. In August 2012, the Operator submitted a Revised FDP (RFDP) with lower OGIP (3.60 tcf) and recoverable reserves (2.90 tcf). Table 9 shows the volume of OGIP and Recoverable Reserves under IDP, AIDP and RFDP. In this regard, MoPNG stated (June 2014) that *"the downward revision of reserves by the Contractor under revised plan has not been agreed to, as the Contractor has not technically demonstrated with any new data or by drilling new wells in other than main channel"*.

Table 9 : Statement showing OGIP and Recoverable Reserve

S.N.	Plan	Month/Year	OGIP	Recoverable Reserve
1.	IDP	May 2004	5.45 tcf*	3.81 tcf*
2.	AIDP	October 2006	12.587 tcf*	10.03 tcf*
3.	RFDP	August 2012	3.60 tcf	2.90 tcf

* *MC / DGH approved figures.*

2.6.2.7. Audit noted the views expressed at the time of examination of the development plans by DGH consultants. Some of the reservations expressed by the experts at that time are quoted below:

Shri P.V. Ramana, Consultant (Reservoir Studies) – 13 October 2004

IDP pertains to a portion of the two channel complexes – Channel A & Channel B – comprising of D-1 and D-3 discovery areas. The area earmarked for development encompassing the two channels 'A' and 'B' is small. The two channels and their depositional elements are fairly well identified and evaluated geologically and petrophysically, in spite of the heterogeneity of the channel fills.

N.C. Nanda, Petroleum Geophysicist, Consultant - 27 August 2004

"The degree of complexity can be judged from the fact that it is very hard to interpret the geological history and palaeography of the individual channels from existing seismic data and also from the extremely varying characters of the four wells logs where any kind of correlation is even beyond attempt. Under the circumstances, the reservoirs may not have good continuity vertically and/or laterally. However, continuity under static reservoir conditions may not be the same as connectivity when the reservoir is depleted, under dynamic conditions.

The two mapped channel systems 'A' & 'B' also indicate to diverge towards east with widening inter-channel area suggesting perhaps poor/no inter-channel continuity. The four well sampling data in a complex subaqueous channel system covering an area of about 90 sq. km. is too inadequate for proper calibration and to predict the thickness of pay sands away from wells with high confidence. The level of confidence will improve with more wells drilled in an optimally phased manner and gas produced".

Shri J.M.B. Baruah, DGH's consultant - 10 November 2006

"The need for preparation and submission of a revised Development Plan with higher capacity appears to have arisen out of the following compelling reasons:

(a) Very steep escalation in cost of executing the work programme of IDP, and

(b) Delay in executing the IDP.

The factors which contributed to more than doubling of the 2P reserves have not been brought out clearly in AIDP. For a better understanding of this large variation in reserves estimation, DGH should independently study the Gaffney, Cline & Associates (GCA) report. In this connection, it may be noted that GCA may not have certified the reserves. This needs to be verified by DGH. The wide variation in estimation of reserves does, however, suggest that the reservoirs have not yet been fully understood. A high rate of subsidence of the over-burden could result in fracture/faulting extent to the surface with disastrous consequences.

The reservoir sands encountered in D1 & D3 gas fields are highly unconsolidated. The grain size also varies widely. The geo-mechanical studies indicated reservoir compaction as a result of reservoir pressure drop after start of production. This could lead to a significant drop in reservoir rock permeability with attendant drop in well productivity even from the high permeability layers.

The other production problem that would be associated with un-consolidated sands is the sand ingress problem. Effective sand control measure adopted to neutralize the sand ingress problem could result in drop in well productivity.

A lower gas production rate would ensure a slower rate of subsidence of the sea bed. This has important environment impact. A high rate of subsidence of the over-burden could result in fracture/faulting extend to the surface with disastrous consequences".

2.6.2.8. In response to the Operator's proposal to revise recovery factor from 75 *per cent*, given in the AIDP, to a new value of 85 *per cent* citing that good quality of sand and absence of aquifer activity would help in achieving recovery factor of 85 *per cent*, DGH approved (December 2006) a recovery factor of 80 *per cent*. DGH, in its reply (January 2014) to Audit, continued to refer to data generated and examined by the Operator and its validation by international experts appointed by the Operator but did not mention how it had ensured accuracy and realistic nature of the data before agreeing to the approval of AIDP in MC. In this regard, MoPNG stated (June 2014) that *"the basis of a higher reserve estimate under AIDP was increase in the estimated OGIP. There was no contradicting estimate of recovery factor by any consultant. The recovery factor estimated by DGH was more conservative than the estimates of international consultant"*. However, DGH did not give any clarification as to how it considered / rebutted the views of its own consultants as mentioned above while approving the AIDP.

2.6.2.9. Interestingly, DGH informed (04 May 2007) MoPNG that as per IDP, OGIP was estimated at 7.6 tcf and recoverable reserves were at 5.32 tcf. However, approval of IDP documents indicated that DGH had considered OGIP as 5.45 tcf and recoverable reserves as 3.81 tcf. It is not clear how different estimates of reserves of gas were reconciled by DGH and the basis of information furnished to MoPNG.

2.6.2.10. MoPNG in its reply (June 2014) stated that *"in general, the Contractor's reserve estimations are examined by a multi-disciplinary team at DGH, including Consultants, based on geological data obtained and interpreted by the Operator and their technical experts including international agencies hired by the Operator"*. MoPNG accepted that *"the reserve figures considered by DGH were those validated by reputed international agencies hired by Operator"*.

2.6.2.11. On this audit issue, the Operator in its reply to MoPNG (June 2014) stated that *"it is not uncommon for the reserve estimates to differ widely depending on the geological conditions and consistency cannot be assured, for reason reserves are always estimated in terms of probability and not certainty"*.

2.6.2.12. MoPNG and DGH are responsible for scrutinizing FDPs prior to their approval. 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. Clearly, the DGH went along with the estimates of the Operator even when its own consultants had expressed reservations.

2.6.3 Implementation of AIDP and decline in production

2.6.3.1. As per the AIDP, the Operator proposed to drill and develop 50 producing wells (22 producing wells in Phase-I and 28 producing wells in Phase-II) to maintain a plateau production rate of 80 mmscmd[42] for eight years. However, MC, after discussions approved plateau production for six years. This was as against 34 producing wells envisaged under

[42] *Million Metric Standard Cubic Meters per Day.*

IDP. The facilities created under AIDP were stated to be upgradeable to production of 120 mmscmd. Table 10 below shows the number of development wells that were required to be put on stream as per the approved AIDP.

Table 10 : Number of development wells that were required

Date	Phase	Number of Producers wells	Gas Rate (mmscf/d)	Average gas rate (mmscmd)
01/07/2008	Phase I	9	975.337	27.63
01/07/2009		18	1885.76	53.42
01/07/2010		22	2185.34	61.90
01/07/2011	Phase II	31	2825	80
01/07/2012		40	2825	80
01/07/2013		50	2825	80
01/07/2014		50	2825	80
01/07/2015		50	2825	80
01/07/2016		50	2825	80
01/07/2017		50	2437.85	69.06
01/07/2018		50	2075.63	58.80
01/07/2019		50	1407.94	39.88
01/07/2020		50	794.448	22.51

2.6.3.2. Although the Operator was required to drill, connect and put on stream 22 wells as per approved Phase I of AIDP, however, the Operator had drilled, completed and connected only 18 wells[43] (against Phase I) upto 2011-12 in the main D1-D3 reservoir area, i.e. Channel A and B.

2.6.3.3. The Operator drilled four more wells[44] during the period, August 2010 to August 2011 but these wells were not connected to the production facility due to inadequate incremental volumes reported by the Operator. The Operator stated to DGH (March 2012) that "*these wells would not produce adequate incremental volumes to justify the additional capex spent on completing and connecting them. It was for this commercial reason that it was decided not to connect these wells to the production facilities*".

2.6.3.4. Production from the D1-D3 field commenced in April 2009. Table 11 shows the details of wells drilled and planned in D1-D3 development area, and approved production *vis-*

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[43] *A1, A2, A5, A6, A9, A10, A13, A16, A20, B1, B2, B4, B6, B7, B8, B11, B13, B15.*

[44] *A21, A22, B16 & SB1.*

à-vis actual production upto 2012-13.

Table 11 : Approved production *vis-à-vis* Actual production

Year	Number of Producer wells		Shortfall	Average Gas Production (mmscmd)		Excess/ Shortfall
	Planned as per AIDP (Cumulative)	As per Actual (Cumulative)		Approved production profile	Actual Production	
2009-10	9	9 to 18		27.63	39.31	+ 11.68
2010-11	18			53.42	48.13	- 5.29
2011-12	22	18	4	61.90	35.33	- 26.57
2012-13	31	18	13	80.00	20.87	-59.13

2.6.3.5. Gas production started declining in August 2010. While production level achieved in 2010-11 was 90 *per cent* of approved production profile, this decreased to 57 *per cent* in 2011-12 and 26 *per cent* in 2012-13. In this regard, the Operator in its reply to MoPNG (June 2014) stated that *"after starting the production from the field following the AIDP, the field experienced significant pressure and production rate decline due to lower in-place gas volumes to support production"*.

2.6.3.6. On a query from Audit, DGH informed (January 2014) that as of March 2012, out of 18 wells connected, only 12 wells were producing gas and six wells[45] had ceased to flow due to water and sand ingress.

2.6.3.7. Audit scrutiny of the documents in this regard revealed the following:

- In December 2010, the Operator submitted the WP&B for the FYs 2010-11 (RE) and 2011-12 (BE) without providing the production / sales projections of D1 -D3 gas field and MA oilfield as required under Article 10.9 and 10.13 of PSC. Although DGH requested (January 2011) the Operator to provide these projections, since no response was received from the Operator, DGH returned (January 2011) the WP&B in original.
- In response, the Operator re-submitted (February 2011) the WP&B partially addressing the concerns of DGH by providing production projections for D1-D3 for the FY 2010-11 (RE).
- While examining these submissions, DGH found that the production projections were not in line with the approved AIDP. Consequently, DGH advised the Operator to modify the WP&B accordingly to drill and put on stream more wells as envisaged in FDP (AIDP). However, the Operator replied (March 2011) that the drilling,

[45] *A2, A6, A10, B2 & B13-Water and B1-Sand.*

completion and field installation of five new wells cannot happen before mid-2014. DGH opined (March 2011) that the Contractor's inability to put on stream new development wells before mid-2014 was a major deviation from the AIDP commitments and timelines. DGH, therefore, did not agree to the revised oil and gas production profile as submitted for 2011-12 (BE) and proposed for 2012-13 and advised the Contractor to workout suitable plans and achieve the AIDP production profile.

- With the production from these fields showing an increasingly declining trend, DGH suggested (April 2011) a course of action which involved re-casting the production profile based on (i) drilling of two wells, completing and connecting four wells in the first quarter of 2011-12 and drilling, completion and connection of nine wells during 2011-12. The Operator rejected this course of action stating (April 2011) that no provision in the PSC stipulates that Contractor's estimates of production are to be in line with the FDP and that there was no justification for drilling the number of wells as suggested by DGH during 2011-12.

- In May 2011, the course of action advised by DGH was repeated by MC in its meeting. Thereafter, Operator re-submitted (May 2011) a recast WP&B for the FYs 2010-11 (RE) and 2011-12 (BE). However, the re-cast WP&B did not have firm commitments in respect of all the suggestions made by MC / DGH for drilling of wells:

  - *FY 2011-12 (BE) – Firm: 3 wells, To mature: 08 wells for FY 2011-12 which will be firmed up on the basis of the result of the three firm wells;*
  - *FY 2012-13 (Provisional) – To mature 09 wells;*
  - *Drilling, connecting and commissioning of the new wells may not be possible before mid 2013.*

2.6.3.8. While confirming these facts, DGH stated (January 2014) that *"the Contractor was advised and reminded by DGH vide number of letters not only to complete, connect and put on production these 4 wells drilled in 2010-11, but was also directed to drill, complete and put on production the remaining number of wells in line with approved AIDP to attain the projected gas production rate. But operator did not connect them, and also did not submit computations to establish that incremental volume is inadequate for economic operation*".

2.6.3.9. Since the production performance of D1-D3 gas fields was not in line with the approved AIDP, DGH advised the Operator on several occasions[46] to drill, complete and connect more wells in line with the approved AIDP. The Operator while explaining (30 April

[46] *23 February 2011, 01 March 2011, 30 March 2011, 05 April 2011, 13 April 2011, 06 June 2011, 11 July 2011, 08 August 2011, 19 September 2011, 17 February 2012, 27 April 2012.*

2011) the production status stated that *"seeing the behavior of D1-D3 field…… drilling of additional wells in main channel area, as originally envisaged in the AIDP, has not been advisable"*. The Operator felt that additional wells may not help to significantly improve either production rate or recovery. DGH noted (19 September 2011) that the Operator had submitted the AIDP after carrying out extensive G&G (Geological and Geophysical) studies and drilling work programme and on the basis of detailed study and analysis had carried out in-house and further validation by engaging international reputed agencies like Gaffney, Cline & Associates (Report – October 2006).

2.6.3.10. The Operator did not adhere to the approved AIDP in terms of numbers of producer wells to be drilled and connected, and gas rate, even after repeated reminders. There was extensive correspondence by the Operator with the DGH reiterating the same views and providing information with delay, by which time decisions were in the nature of *fait accompli*. DGH also stated (March 2014) that *the Operator provided their response to DGH queries, after some delay and some of it was repetitive in nature, despite regular follow-up by DGH.*

2.6.3.11. With the differing views of DGH and Operator, DGH decided (April 2011) to get the performance evaluated by Mr. P Gopalakrishnan (Consultant). The Consultant noticed (April 2011) that *"the field has been started and produced as per the expectations for a year or so, but the Operator did not drill the wells as per the AIDP by the end of first year, thereby affecting a rate-decline, and a consequent partial regain of the reservoir pressure…All 18 wells are in the main D1-D3 reservoir area, exposing the main channel sand reservoir and the layered (laminated) reservoir. The two wells, drilled in 2010 but not connected, are also in the main reservoir area. Besides, the exploitation of the layered reservoir does not seem to be at the desired level, although this reservoir unit corresponds to nearly 60 per cent of GIIP. Considerable areas have been left in the proven areas (1P) of D1-D3 fields, while there has been no drilling in the inter-channel areas, where the reserves are yet to be proved…."*.

2.6.3.12. The Consultant recommended that :

- *The shortfall of gas production is due to non-drilling of the adequate number of wells as per AIDP and therefore drilling as per the AIDP may be undertaken immediately.*
- *The thick high permeability reservoirs at the base of the pool (in both A & B areas) have undergone more withdrawal. Therefore, for future wells, a different completion strategy may be required to drain the layered thin sand groups more effectively.*

2.6.3.13. The Consultant also stated that delays in commissioning additional producers would trigger water drive in the reservoir and consequent reduction of the ultimate recovery as a result of water encroachment as well as permanent loss of some of the Gas Reserves.

The Operator opined that "*no provision in the PSC stipulates that Contractor's estimates of production are to be in line with the FDP*". However, Operator's opinion has to be viewed in the context of Article 10.9 of the PSC which states that "*A Development Plan approved by*

MC or Government, as may be the case, from time to time shall commit the Contractor to the obligations stipulated in Articles 10.11 to 10.13". The AIDP was approved in December 2006. Further, Article 10.12 provide that "*The Management Committee... may require the Contractor to prepare an estimate of potential production to be achieved ... for each of the three (3) Years following the year to which the Work Programme and Budget relate.... If major changes in Yearly estimates of potential production are required, these shall be based on concrete evidence necessitating such changes......*". As previously noted[47], the approval of annual WP&B for 2010-11 (RE) got delayed as the Operator did not submit relevant data. Moreover, as per Article 10.13 of the PSC, "*Not later than the fifteenth (15th) of January each year, the Contractor shall determine the "Programme Quantity" with the approval of the Management Committee. The Programme Quantity for any Year shall be the maximum quantity of Petroleum based on Contractor's estimates, as approved by the Management Committee, which can be produced from a Development Area consistent with Good International Petroleum Industry Practices and minimising unit production cost*".

2.6.3.14. Instead of carrying out activities as suggested by DGH as per the commitments[48] under the PSC, the Operator submitted (August 2012) another development plan, i.e. RFDP, for D1-D3 gas fields on the basis of the collected and analysed production data of D1-D3 gas fields for approval of MC. The RFDP is based on estimated OGIP of 3.6 tcf. The Operator worked out three cases as shown in Table 12, with different recovery factors.

Table 12 : Different scenarios projected in RFDP

Scenario	Gas Production period	Total Gas Recovery in BCF	Recovery Factor *per cent* with OGIP of 3.6 tcf	Total Capital Expenditure ($ MM)
Case I	upto 2015-16	2309	64	377
Case II	upto 2020-21	2867	80	531
Case III	upto 2022-23	3032	84	1110

2.6.3.15. The Operator recommended Case II. The Operator stated that there was a need to do 'workover' on the existing wells and would not drill any other well. Further, any delay in execution of the work might lead to early field closure in 2015-16.

2.6.3.16. DGH stated (January 2014), "*the Operator was repeatedly asked to drill the wells in line with approved AIDP and because of the failure of the Operator to do so, the revised assessment by the Contractor of downgraded reserves with reduced production profile forming a part of RFDP for D1&D3 gas fields has not been approved by DGH / MoPNG*".

2.6.3.17. If MoPNG / DGH does not approve the RFDP then Case I scenario would prevail

[47] *Para 2.4.1 and 2.6.3.7*

[48] *In the budget FY 2011-12 (BE) and FY 2012-13 (Projected), Operator indicated gas production rate of 43 mmscmd and 38 mmscmd for 2011-12 and 2012-13 respectively which was below the MC approved FDP.*

and the D1-D3 field as per RFDP, would shut down in 2015-16. It would, thus, appear that the Operator has decided not to drill remaining wells leaving the GoI with little flexibility to make a decision.

2.6.3.18. Audit would like to also mention the views of the Standing Committee on Petroleum and Natural Gas in this regard. The Committee in its Nineteenth Report (October 2013) had stated, "*the Committee are worried and express their unhappiness at the whole series of events. The KG-D6 basin was success story of NELP regime, which invited private companies and MNCs in the exploration and production regime, which until then was a NOCs forte. However, the Contractor has not adhered to the measures suggested by the upstream regulator DGH to drill wells to increase natural gas production. Also coincidentally, the demand for increase in the price of natural gas by the Contractor over and above the discovered price by arm length mechanism as provided in the PSC has also brought question mark regarding the interest of Contractor to abide in the sanctity and stability of the PSC*".

2.6.3.19. The Operator's decision to not drill and connect the committed producer wells as per the approved AIDP even after repeated reminders by the DGH is a matter to be seriously considered and resolved by the MoPNG to ensure the energy security of the country.

Audit Recommendation 5: 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.

2.6.4 Increase in development cost

2.6.4.1. 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 in Phase-I. The AIDP was approved by MC (November 2006) wherein the Operator proposed to incur expenditure in two phases i.e. US$ 5.20 billion in Phase-I (upto 2008-09) and US$ 3.63 billion in Phase-II (beyond 2008-09). The total cost of D1-D3 development was to be US$ 8.83 billion in two Phases. The actual spend has increased though the Operator had informed MC that the cost for Phase-I was mainly based on commitments/ contracts already finalized.

2.6.4.2. An analysis of some of the major expenditure incurred for installing various facilities and equipments in the D1-D3 gas fields, revealed the following:

- Onshore Terminal (OT) was constructed at a cost of US$ 827.68 million as against estimated cost of US$ 550.87 million, i.e. increase of US$ 276.81 million. The increase was mainly attributable to the fact that at the time of submission of AIDP (October 2006), OT engineering was in initial stage and the Operator carried out major engineering activities after submission of AIDP. Further, the work of construction was initiated without having a concrete design in place and resultantly, the Operator had to introduce frequent Change Orders during the execution of the construction contract.

- Six Subsea manifolds were installed at the cost of US$ 80.19 million as against the estimated cost of US$ 70.81 million.
- Pipelines and Pipeline End Manifold were installed at the cost of US$ 1019.43 million as against the estimated cost of US$ 906.92 million. The increase in cost was due to changes in the design engineering of hardware and complications encountered during installation and distance between the wells and manifolds.
- Control cum Riser Platform (CRP) serves as a hub for receiving gas production from deepwater pipeline manifold and for diverting it to OT through pipeline. It was constructed at a cost of US$ 571.39 million as against estimated cost of US$ 446.83 million. The cost mentioned in the AIDP was indicative and without any detailed engineering. Therefore, actual work includes additional work and revision of work scope which resulted in increase in engineering man-hours and engineering cost.

2.6.4.3. DGH confirmed (January 2014) that *"the expenditure of US$ 5.76 billion claimed by the Contractor includes certain items which did not originally form part of US$ 5.20 billion"*.

2.6.4.4. According to the provisions and spirit of PSC, MC / DGH, is responsible for ensuring that all the cost estimates are reasonable and realistic. However, Audit found no evidence to obtain assurance that the estimates had been duly verified by MC / DGH.

2.6.4.5. DGH, however, argued (January 2014) that *"the Audit may confirm that if there are items of expenditure not authorized by MC either at the stage of AIDP approval or at the stage of annual work programme & budget, or where the actual cost has increased without adequate explanation in spite of estimates being based mostly on commitments/contracts already finalized, then such costs may be flagged for disallowance of their recovery……The provisions of PSC have been somewhat misinterpreted. The correct interpretation of the PSC is as follows:*

i) The MC should examine and approve mainly the physical components of the development plan.

ii) The Contractor should follow the procurement procedure, approved under the PSC, while procuring various goods and services for the approved physical components of the development plan.

iii) The auditor, while auditing the accounts of the Contractor, has to verify, among others, that the goods and services have been procured in accordance with the PSC provisions and as per the requirements of approved development plan.

iv) It is, therefore, the responsibility of the auditor to go into various costs after they have been incurred and to recommend disallowance of such costs which are in violation of

PSC provisions. It is for this reason that tentative estimates considered, if any, by the MC do not automatically entitle the Contractor for any cost recovery under the PSC.

v) *The paragraph gives the example of detailed design, engineering, drawings, infrastructure, materials etc. not being available and about change orders for purchase of subsea equipments. It needs to be clearly understood that the PSC does not require DGH / MoPNG to assume the role of a project manager for each major item of expenditure in each of the 300 odd PSCs signed so far".*

2.6.4.6. Reply of the DGH is not acceptable because Article 6.6 of the PSC stipulates that the Annual WP&B in respect of development and production operations are to be approved by MC. As such, the Operator is not entitled to incur any expenditure without the approval of the WP&B by the MC. Therefore, it is the primary responsibility of the DGH to review WP&B in detail within the prescribed PSC time-limit for control of the expenditure.

2.6.4.7. The Operator in its reply to MoPNG (June 2014) stated that *"AIDP approved by the MC envisaged an estimated Capex of $ 8.8 bn to be spent in two phases. The implementation of Phase II was contingent on the progress of Phase I and would be subject to any revisions dictated by that experience. Against an initial estimated development cost of $ 8.8 bn the actual expenditure incurred till 31.03.2012 is only about $ 5.76 bn. Even though there was an increase in the development cost beyond initial estimates of $ 5.2 bn for Phase I, Contractor strived to resolve cascading effects of delays in a real time horizon covering several logistical, regulatory, and other obligations across separate piecemeal items. Contractor also strived and to minimize Total Installed Cost (TIC) within shortest possible completion time without compromising safety and quality to ensure the success of the Project 'as a whole'".*

2.6.4.8. Reply of the Operator is not acceptable since as per the MC approved AIDP (Phase-I), the cost of drilling and connecting of 22 wells and gas production facility for 80 mmscmd was US$ 5.2 billion, whereas the Operator had drilled 22 wells but connected only 18 wells alongwith other production facilities at the cost of US$ 5.76 billion. This clearly shows that there has been an increase in the Phase-I development cost even though the Operator had not fully completed the Phase-I development plan.

2.6.5 Under-utilisation of gas handling facilities

2.6.5.1. The AIDP envisaged plateau production rate of 80 mmscmd, with first gas production by mid-2008. The Operator submitted (November 2006) a detailed proposal to DGH indicating that capex would be incurred in two phases, i.e. US$ 5.20 billion in Phase-I (upto 2008-09) and US$ 3.64 billion in Phase-II (beyond 2008-09). The Operator had not started (December 2013), Phase II development work, including drilling of producer wells. However, Phase I activities had been undertaken.

2.6.5.2. 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 for instance,

- in the case of the OT, nearly 50 *per cent* of the trains comprising of slug catcher, production separator, gas filter coalesce, gas turbine generators etc. remained unutilized,
- the facilities created in the CRP, due to decline in trend of gas, remained underutilized,
- in the case of the six subsea manifolds, each manifold was designed to connect six wells, however, only eighteen wells have been, attached with these manifolds, till date. Due to non-attachment of remaining wells, 50 *per cent* of these facilities also remained unutilized.
- lastly, three 24" pipelines were installed from CRP to OT and two 24" pipelines from CRP to Deep Water Pipeline End Manifold. The Operator (in AIDP) informed that pipelines were designed to handle 80 mmscmd of gas with provision to expand upto 120 mmscmd and third pipeline between OT and CRP would assist in increasing the plateau capacity beyond 40 mmscmd and also for adequate redundancy, in case one pipeline failed. Due to decrease in the present gas production level and not drilling of wells as per approved AIDP, two pipelines would appear sufficient to supply gas from CRP to OT and therefore, the third pipeline installed after incurring US$ 182.73 million had remained idle rendering this expenditure unfruitful.

2.6.5.3. DGH stated (January 2014), "*this office agrees with the finding of under-utilization of facilities due to decline in production, and this has been the basis of disallowance of cost recovery to the tune of US$ 1.005 billion upto 2011-12*".

2.6.5.4. The Operator in its reply to MoPNG (June 2014) stated that "*the capacity of the existing facilities and in-built design flexibilities shall be effectively utilized for integration of R-Cluster, Satellite & Other Satellite fields.... From a critique's perspective, it may appear that the facilities are under-utilized; however, from an integrated & holistic view taking into consideration that these facilities have been utilized for D1-D3 over the past 5 years and will continue to be efficiently utilized for future development, Contractor believes that the expenditure incurred on existing facilities is justified".*

2.6.5.5. Operator's comments may be viewed in the light of the fact that the facilities were created for D1-D3 gas fields under their development plan which remained underutilised. Operator's justification for their future utilisation on the basis of development plan of other fields is not acceptable as these plans are at varying stages of submission/approval.

2.6.5.6. During the Exit Conference (July 2014), Operator stated that *"this matter being under arbitration, is sub-judice and any inference drawn on this issue in the audit report would be prejudicial to the interest of the parties to the PSC".*

2.6.5.7. It may be noted that as per Article 33.12 of the PSC "*in so far as practicable, the Parties shall continue to implement the terms of this Contract notwithstanding the initiation of arbitral proceedings before a sole expert, conciliator or arbitral tribunal and any pending claim or dispute"*. Further, this audit has been undertaken on the request of the GoI (one of the parties) with the scope, extent and manner as specified in Article 25 and Appendix C of the PSC.

2.6.6 Viability of Optimized Field Development Plan (OFDP)

2.6.6.1. The Contractor submitted (July 2008) Development Plan (DP) of nine Satellite Gas Discoveries[49] (SGD) for the approval of MC. The DP envisaged estimated gas reserves of 2200 BCF, capex of US$ 5910 million with expected gas from mid-2013 onwards subject to approval of the plan by January 2009. DGH after carrying out techno-economic study of DP at a gas price of US$ 4.20 per mmbtu, observed (February 2009) a negative net present value (NPV) of cash flow from the project at a discounting factor of 10 *per cent* and advised (March/April/ November 2009) the Contractor to re-consider the DP and submit timeline of submission of DP for the approval of GoI.

2.6.6.2. The Contractor submitted (December 2009) an OFDP for four satellite discoveries[50] with OGIP of 1513 BCF, gas production rate of 10 mmscmd from eight wells at an estimated capex of US$ 1.529 billion. After in-house study and correspondence with the Contractor, DGH carried out techno economics on the production profile, cost estimates and project schedule which yielded a negative NPV of US$ 239 million. DGH also worked out another scenario by excluding royalty as expenditure from revenue and phasing of capex in two years, making the project marginally economically viable (with an NPV of US$ 33 million).

2.6.6.3. Given the negative NPV and the fact that estimated capex was based on Contractor's in-house estimates of 2006 without carrying out Front End Engineering & Design (FEED) and detailed engineering, DGH informed (August 2011) MoPNG that OFDP may not be techno-economically viable at a gas price of US$ 4.2/ mmbtu.

2.6.6.4. MoPNG advised (23 December 2011) DGH to work out different economic scenarios with 10 *per cent* and 15 *per cent* (both positive and negative) variations in capex and break-even price/ mmbtu for each variance. After working out four scenarios (both positive and negative) with 10 *per cent* and 15 *per cent* variance DGH worked out a break-even rate per mmbtu between US$ 4.34 per mmbtu and US$ 5.81 per mmbtu and requested (December 2011) MoPNG to take a view on the matter. The lowest break-even rate was higher than gas price of US$ 4.2 / mmbtu.

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[49] *D-2, D-4, D-6, D-7, D-8, D-16, D-19, D-22 and D-23.*

[50] *D-2, D-6, D-19 and D-22.*

2.6.6.5. MoPNG asked DGH (02 January 2012) to work out the viability of the proposed satellite fields by taking the total production into account at Weighted Average Price (WAP) as the gas produced from four SGD would be sold along with the gas produced from D1-D3 and MA fields on the gas price of US$ 4.2 per mmbtu fixed by Empowered Group of Ministers (EGoM) for the entire contract area. Accordingly, DGH computed the WAP of gas for the entire block considering the producible reserves of D1-D3 and MA fields at the rate of US$ 3 per mmbtu and the four SGD at the rate of US$ 5.8 per mmbtu, which varied in the range of US$ 3.15 per mmbtu to US$ 3.22 per mmbtu. The project was now found to be viable by DGH and MC approved OFDP on 3 January 2012.

2.6.6.6. From the above facts, Audit observed that

- MoPNG/DGH has not fixed any norms/criteria for working out techno-economic analysis of a FDP.
- Initially, the OFDP was not techno-economically viable, however, it was made marginally viable by devising different scenarios and changing assumptions e.g. exclusion of royalty as expenditure, variation in capex etc.
- MoPNG had directed (30 September 2011) DGH to engage a 'third party for validation' of capex of OFDP. In view of non-submission of earnest money/bid security and conflict of interest, DGH informed (19 December 2011) MoPNG that it was not possible to get the third party validation of capex of OFDP. However, before MoPNG could take any decision on the matter, MC approved OFDP in January 2012. Therefore, in the absence of validation of capex by third party, the reasonability and justification of capex and GoI share of PP could not be assured.

2.6.6.7. DGH in its reply (October 2012) stated that

(i) The FDP involves monetization of four satellites gas discoveries holding substantial reserve of 0.617 tcf of gas. The Contractor had evaluated techno-feasibility of project at a gas price of US$ 6 per mmbtu.

(ii) However, when the project was evaluated in DGH at current gas price of US$ 4.20 per mmbtu, the project was showing negative NPV. Non-monetization of gas on ground of such evaluation at a gas price of US$ 4.2 per mmbtu would result in huge loss of gas production, particularly keeping in view the higher gas price paid for other blocks. Therefore, different scenarios were tested such as with shorter gestation period, excluding royalty, capex escalated/ depressed by 10 and 15 per cent.

(iii) Royalty is Cash-in-flow to one of the stock holders that is, GoI and hence excluded as expenditure in one of the scenario evaluation.

(iv) Capex that will be considered for cost recovery will be restricted to actual cash flow duly certified by auditor, including CAG.

(v) *In order to evaluate the range of economic feasibility of project with reference to possible gas prices, it was computed that the Break Even price was on the range of US$ 4.34 to US$ 5.81 when Capex was escalated by +/- 10 per cent to 15 per cent.*

2.6.6.8. MoPNG in its reply (June 2014) stated that

- *the economic viability was evaluated at different scenarios so as to optimize the decision making in order to avoid non-development of any discovery.*
- *Techno-economic evaluation is guided by principles of economics and application of mind. Setting separate norms for economic evaluation may not be possible.*
- *D1 & D3 and MA were evaluated at different points of time. Hence different prices were used for evaluation done at different points of time.*

2.6.6.9. The Operator in its reply to MoPNG (June 2014) stated that *"small and marginal and commercially borderline discoveries are best developed along with existing ones as it improves their chance of production. Having found the hydrocarbon reserves, by utilising the existing infrastructure facilities, the existing contractor is better placed to make these marginal/small reserves economically viable for development within couple of years as against leaving them undeveloped forever... Evaluating the FDP at a sub market price and then declaring it unviable was not only against the PSC, but was tantamount to suppressing much needed production in a country suffering from lack of gas".*

2.6.6.10. In the opinion of Audit, reply of DGH/MoPNG/Operator is to be considered in view of the following:

- There is no rationale for working out techno-economics after taking WAP at the rate of US$ 3.0 for D1 & D3 gas fields & MA oilfield gas and US$ 5.8 per mmbtu for OFPD, as GoI had fixed the price of gas of US$ 4.20 per mmbtu.
- At the time of evaluation of OFDP, the prevailing gas price for KG-DWN-98/3 was available, therefore, there was no need to use different prices.
- OFDP estimated capex was based on Contractor's in-house estimates of 2006 and the Contractor had not carried out FEED and detailed engineering till approval of OFDP. Hence, capex was not realistic and chances of cost escalation cannot be negated.
- Royalty had been considered as expenditure for calculating IM, hence, cannot be excluded as expenditure.
- WAP for economic evaluation of OFDP indicates that insufficiency, if any, of the OFDP would be compensated with the revenue of D1&D3 and MA fields, which are already producing less gas/oil than the approved production profile.
- Carrying out financial due diligence prior to approving the plan is of greater importance since the Contractor is entitled to incur expenditure with the approval of annual WP&B and the responsibility of an auditor would be a *post facto* exercise.

2.6.6.11. Audit is not against development of small and marginal and commercially borderline discoveries. Audit's main concern is that there should be an appropriate framework which takes into account all the relevant factors for working out techno-economic analysis of a FDP for such discoveries. It becomes all the more important since the country cannot afford to lose out even a small discovery in order to achieve energy security. Thus, MoPNG should fix norms/criteria for working out techno-economic analysis of a FDP keeping in view the GoI's policy regarding gas utilization in the country.

Audit Recommendation 6: MoPNG may consider fixing norms / criteria for working out techno-economic analysis of a FDP.

2.7 Expenditure related issues

Audit reviewed the expenditure incurred on a sample / test-check basis from the point of view of compliance and propriety in relation to PSC provisions and terms and conditions of the related procurement contract. The selected transactions covered payments pertaining to contracts awarded earlier but which took place during the period 2008-09 to 2011-12 and also contracts awarded during this period. Result of such audit examination revealed instances where payments made were not in line with contractual provisions leading to additional and inadmissible expenditure, as detailed below.

2.7.1 Grant of concessions against contractual terms

2.7.1.1 Contract for Engineering, Procurement, Installation and Construction of offshore facilities

2.7.1.1.1. The Operator awarded contract number OG8/3611335 dated 4 October 2006 to M/s Allseas Marine Contractors S.A. (AMC) for Engineering, Procurement, Installation and Construction (EPIC) of offshore facilities for development of D1-D3 fields for a basic contract price of Euro 764.08 million comprising a lump sum price of Euro 699.09 million and provisional price of Euro 64.99 million. As per the milestones specified in the contract, Milestone 2, i.e. "Completion of pre-commissioning and ready for start-up of first set of 9 wells" was to be achieved by 15 May 2008 while Milestone 3, i.e. "Completion of pre-commissioning and ready for start-up of second set of 9 wells", was to be achieved by 17 July 2008.

2.7.1.1.2. However, as AMC was not able to achieve the above milestones, it informed the Operator on 20 June 2008 that various factors attributable to the Operator were preventing it from performing its obligations under the contract, rendering it inoperable both in delivery and contract administration. AMC mentioned that the delays attributable to Operator had escalated to the extent that the AMC's third party contractual commitments were endangered. According to the AMC, all parties involved: Operator, AMC and its sub-contractors were responsible for respective delays on this project. The AMC further mentioned that if the Operator wished to change the sequence of the work in order to achieve an earliest possible

First Gas date then the Operator should pay for the extra expenses to achieve the same. Moreover, the Operator would need to pay for the extra expenses already incurred in the past months due to deviations from the scheme suggested by AMC.

2.7.1.1.3. Operator, however, refuted (25 June 2008 and 7 August 2008) the AMC's assertions that delays attributable to it were preventing the AMC from performing its obligations and asked the AMC to acknowledge and accept responsibility for its lack of performance, such as inordinate delay in mobilization of key resources, slow progress on almost all fronts, poor performance of vessel 'Eclipse', sub-optimal overall implementation, quality related issues, inefficient planning and management, inadequate manpower etc.

2.7.1.1.4. In order to resolve the contract related issues with the AMC and also to expedite completion of the works, correspondence and discussions were held between Operator and the vendor during June, July and August 2008.

2.7.1.1.5. After discussions with the AMC, Operator submitted a proposal before the OC of KG-DWN-98/3 Block on 1 September 2008 requesting it to grant some concessions requested by the AMC. Regarding delays and penalties, the Operator noted that the limit of maximum Liquidated Damages (LD) payable under the contract had been reached and AMC had virtually no incentive to complete the project. The Operator also mentioned that even though the contract stipulated that additional resources required for meeting the milestones were to be mobilized by AMC, i.e. at own cost, it thought that in the interest of the project it should not take a stand which could discourage AMC to complete the work as such a move would prove to be counterproductive. The Operator reasoned in the proposal that AMC had grounds to claim that they had considerably overshot their cost estimate for executing the work and, in fact, due to the delay in supplying of Free Issue Materials (FIM) and delay in completing CRP the Operator had contributed, to an extent, in delaying AMC's work. Other reasons for not achieving the milestones were new regulations of Specific Period License (SPL) issued by Directorate General of Shipping (DGS) having impact on schedule and periodic intrusions by fishing boats in the area of operations, etc. Thus, applying LD and forcing AMC to mobilize additional resources at its cost would lead to litigation at that juncture, thereby, delaying the project further.

2.7.1.1.6. Based on the justification provided by the Operator, the OC agreed (2 September 2008) to give the following concessions to AMC, the estimated impact of which was Euro 200 million approximately:

- To provide additional resources required for expediting the offshore work without any cost to AMC or recovery from them.
- To release the subsea construction vessel Helix Express and instead mobilize the vessel Rem Forza by paying mobilization fee.
- To provide additional diving spread at no cost to AMC.

- To pay additional amount of Euro 95 million to the vendor for delays not attributed to AMC.
- To relax levy of LD.
- To pay incentive to AMC for achieving first gas by specified date.
- To provide assistance and pay for resources for expediting jumper fabrication.

2.7.1.1.7. Subsequently, with a view to expediting completion of the works, an agreement was signed between AMC and Operator on 13 October 2008 containing a framework for resolution of contract related issues between them, including the above concessions, with the aim of AMC achieving Milestone 2 by 23 December 2008 and Milestone 3 by 18 March 2009.

2.7.1.1.8. Examination of the documents in this connection led Audit to conclude that these concessions did not fall within the purview of the EPIC contract and the PSC provisions. According to Section 3.2 (ix) of Appendix C to the Accounting Procedure to PSC *amounts paid with respect to non-fulfillment of contractual obligations are not recoverable and not allowable*. Therefore, in Audit opinion, these payments (approximately Euro 200 million) should not be recoverable from the Block. Detailed observations follow:

- Excepting the provisional part of the total price (approximately Euro 65 million), the contract with AMC is a lump-sum contract and all costs had been factored in prior to finalizing the contract. Incidentally, detailed pre-bid meetings had been held with the bidders to clarify scope issues and the AMC had revised his original bid upwards[51]. In this regard, Audit noted that there was no specific provision in the contract which entitled AMC to claim the cost overrun for the reasons for which Operator had paid the amount. Nonetheless, on the basis of the terms of the resolution, the Operator made outright payment of Euro 95 million (out of a total cost overrun of Euro 360 million worked out by AMC) to AMC towards its share of cost overrun.
- In terms of clause number 9.5 of the contract, at no time prior to completion should the AMC substitute any marine craft used by the AMC in the performance of the Works without the prior written approval of the Operator. If the AMC wished to seek the Operator's approval for any substitution, the AMC was to ensure that any proposed substitute marine craft, should (a) be of an equal or higher standard and specification; and (b) have the same or better capability and capacity to perform the part of the Works for which it was to be used, than the original marine craft that it was replacing. Further, all and any costs associated with replacing any such marine craft should be for the sole account of the AMC. Additionally, any such substitution or replacement would be at the sole risk of the AMC and should not entitle the AMC to claim for any extension of time to any Milestone Date or the Completion Date or any increase in the Contract Price.

[51] *Audit findings on gaps in the bidding and award process are contained Audit Report No. 19 of 2011-12.*

- Review of Change Order Number 11 dated 1 October 2008 (effective from 20 September 2008), however, revealed that pursuant to the above clause, AMC sought Operator's approval to substitute subsea construction vessel 'Express' with the vessel 'Rem Forza'. Although 'Rem Forza' was not of equal or higher standard and specification compared to 'Express' and did not have the same or better capability and capacity to perform the part of the Works for which it was to be used, Operator acceded to the request of AMC, as the major part of Works to be carried out by 'Express' had been executed by then.
- Although all and any costs associated with replacing the marine craft were to be at the sole account of AMC, the Operator paid US$ 16.87 million to AMC towards mobilization and demobilization costs for the vessel 'Rem Forza'. In Audit opinion, besides the fact that agreeing to AMC's proposal to substitute a marine craft with lower specifications was in contravention of the contractual terms, the reimbursement of the mobilization and demobilization costs was also not in order and had resulted in a payment of US$ 16.87 million to AMC to which he was not entitled. This had also resulted in excess booking which should not form part of cost recovery.
- As per Exhibit A (Scope of Works), para 6.2.3 of the EPIC Contract dealing with Resource and Manpower Augmentation, the AMC should augment the manpower and resources including additional marine spread deployed as and when considered necessary to achieve the milestone dates without any cost and time implication to the Operator. Although Operator was aware that additional resources required for meeting the milestones were to be mobilized by AMC at its own cost, however, in order to avoid litigation and delay in meeting first gas, Operator proposed to provide the additional resources also without any cost to AMC was not as per contractual terms. In this case also, there should not be any cost recovery as it is against the contractual terms.

2.7.1.1.9. Therefore, the amount paid / committed to the AMC towards the additional resources against the estimated amount of Euro 200 million (which included Euro 95 million and US$ 16.87 million) approved by the OC on 2 September 2008 should not be allowable for cost recovery.

2.7.1.1.10. Giving justification for the payments, the Operator, in reply to an audit observation, stated (February 2014) that

From the correspondence and meetings with the AMC it was evident that AMC was steadily losing money on the project having reached a stage where it would have to obtain a loan of a few hundred million Euros to finance its working capital requirements. It had already submitted an interim claim disputing the levy of LD under the contract. It was consequentially approaching a point where they could not have continued with project *execution. If pushed it would at the very least have insisted on following the minimal required contractual sequence for performance of work, without any regard for overall project requirements.*

Contract costs escalated due to various reasons which cannot and could not have been foreseen at the time of award of work. Some of these are listed below:

- *AMC was required to execute the work in a specific sequence as enumerated in the contract and this required Operator to supply the required free issue material (FIM) to AMC, provide the completed wells as stipulated in the contract and also provide access to CRP as required. However, the subsea structures were delayed between 105 to 132 days, umbilicals were delayed by 102 days while the well completions were delayed between 17 to 212 days.*
- *By 15 May 2008, the date of Milestone 2, only 4 wells had been completed.*
- *By 17 July 2008, the date of Milestone 3, total of only 4 wells had been completed.*
- *These delays further had the effect of pushing the installation into an unsuitable weather period for the east coast adding to the installation inefficiencies.*

Thus, while AMC and its subcontractor also could have been held responsible for some delay it was impossible to quantify the responsibility for each entity's delays in a complex and mega project with innumerable dependencies. Any attempt to quantify and apportion would be subjective and could have only been settled through lengthy litigation which would have further delayed the project in addition to increased project costs.

A number of contracts must be executed concurrently and the project decisions made keeping all the aspects in view – the most important consideration being interfaces amongst different contract timelines and the cascading impact of delays of one contract on the other. Number of technical, logistic, regulatory and other obligations including delivery must be resolved/ met by the contractors under each contract in order to ensure success of the Project 'as a whole'.

Auditors have drawn the conclusion that AMC was required to mobilize additional resources at its cost to meet the Milestone dates under the contract. This interpretation is correct in the event AMC was solely responsible for delaying the achievement of Milestone(s). However in the subject instance, the delays occurred due to variety of factors as enumerated in earlier paragraphs.

Under the circumstances, the options before the Operator were not only limited but would have carried dubious legal credibility in view of the fact that it could insist on imposing liquidated damages knowing fully well that certain reasons for delay not being on account of AMC such a decision would have been contested and would only have led to the AMC halting work on the project and getting into prolonged litigation with the Operator.

Operator disagrees with the Audit Team's opinion that agreeing to the AMC's proposal to substitute a marine craft and to reimburse the mobilization and demobilization costs for the vessel 'Rem Forza' was in contravention of the contractual terms, and therefore this should not form part of cost recovery. The Audit Team's opinion does not consider the practical difficulties and issues which led to this operational decision taken by the Operator.

2.7.1.1.11. Audit acknowledges the challenges faced by the Operator; however, successful vendor management and effective contract implementation are responsibilities of any business. Therefore, the Operator's replies have to be viewed in the light of the following:

i. As per Clause 8.4 (A) of the contract, the AMC shall be deemed to have examined all aspects of this Contract and to have fully satisfied itself as to the sufficiency of the Basic Contract Price for the performance and completion of all of its obligations under, and in accordance with, this Contract. Any works not expressly referred to in this Contract but inherently necessary to complete the Works shall be carried out by the AMC and shall be deemed to be included in the Basic Contract Price.

ii. Further, Clause 8.4 (B) provides that except as otherwise specifically provided for in this Contract, AMC shall not be entitled to any increase in the Contract Price in respect of the obligations under this Contract and the Basic Contract Price shall include the performance by the AMC of all its obligations under this Contract and include all overheads, finance charges on capital employed, taxes, profit, costs, charges and other expenses of every kind (except as otherwise expressly stated in this Contract).

iii. Further, as per Clause 26.1, except in relation to fuel as provided for in Schedule 11 (Schedule of Prices), the Basic Price shall not be subject to any adjustment, escalation or other modification (regardless of any fluctuations in exchange rates or the cost of Resources, materials, Equipment, labour or any similar items) and shall be and remain fixed, except as specifically provided for in Clause 26.

iv. Clause 15.1 of the contract stipulates that the AMC agrees that it is of the highest importance to the Company that the Works are progressed and completed in accordance with the Project Schedule, Project Execution Plan, Milestone Dates, Completion Date and all other scheduling obligations of the AMC provided for under this Contract. The AMC shall commence the Works on the Effective Date and shall thereafter proceed to carry out and complete the Works continuously, diligently and without delay in accordance with the Project Execution Plan, the Project Schedule and the other requirements of this Contract. If at any time during this Contract, the Company (Operator) is of the view that the Works are or are likely to be delayed for any reason whatsoever, including for any reasons set out in Clause 15.3 (A), the AMC shall, at its own cost and expense, promptly and diligently take all measures necessary to eliminate or minimize such delay, and shall augment and supplement adequate personnel and Resources as may be required in this regard. Moreover, while submitting the proposal to the OC, the Operator himself had also mentioned that the contract stipulated that additional resources required for meeting the milestones were to be mobilized by AMC i.e. at own cost.

v. Further, as per Clause 8.3 (H), the AMC confirms that it has, prior to the Effective Date (and in addition to its obligations under Clause 8.2 – this relates to inspection of the Site) completed, and kept updated, a full review, and on an ongoing basis upto the Completion Date and obtained an understanding, of all other information (other than mentioned in Clause 8.3 (A) to (G)) as to risks, contingencies or other circumstances of any nature, which a Reasonable and Prudent vendor should have anticipated as being likely to affect performance of the Works.

vi. There is no provision (including the above provisions) in the contract which specifically entitled the AMC to claim the increase in the basic contract price on account of the delays in completion of Works for the reasons for which the Operator had paid him the excess cost. Therefore, since the extra cost was not in consonance with the provisions of the contract, such costs are inadmissible.

vii. Further, Operator's reply is not supported by any provision of the contract which allows it to pay the excess cost due to the reasons for which the Operator has paid the amount.

2.7.1.1.12. AMC had won the EPIC contract, which mainly consists of lump sum price, on bidding basis. AMC being an experienced vendor was expected to be aware of all such kinds of situations and all aspects/provisions of the contract while signing the contract. The AMC was aware of the risks, contingencies etc. in execution of the Works. Therefore, since the payments made towards the increased contract price are in violation of the provisions of the contract, the same are not recoverable from the revenue of the project.

2.7.1.1.13. While it is important to see the success of the project as a whole, nonetheless, individual transactions / contracts of high value and having separate terms and conditions are also required to be implemented. Since additional compensation paid was not in line with contractual provisions, cost recovery for the same should not be allowed.

2.7.1.1.14. The Operator in its reply to MoPNG (June 2014) and during the Exit Conference (July 2014), while reiterating its earlier views, also mentioned that

- *commenting on commercial, operational or technical performance of the Contractor & advancing legal interpretation of provisions contained in the PSC is not appropriate and far exceeds the proper scope of an audit to verify charges and credits under Section 1.9 of the Accounting Procedure to the PSC.*
- *the contract costs escalated due to various reasons which cannot and could not have been foreseen at the time of award of work. The delays including delays caused by*

pipeline walking, weather conditions, delay in providing FIM and late completion of subsea wells or interruption of access to CRP was due to conditions beyond the reasonable control of the Contractor and AMC.

- *the Change clause in the contract is provided to address issues related to changes post award and the Contractor exercised due diligence in finalizing the changes to the contract, which were beyond the control of the parties to the contract.*
- *the Contractor acted as a prudent contractor in taking action to ensure earliest Completion of overall project, mitigate delays and minimize any increase in cost. This was an operational decision and the Contractor was acting in the overall interest of the project and the Parties to the PSC. Thus as clearly evident, there is no violation of the terms of PSC in making payments to expedite the work.*

2.7.1.1.15. In its reply (June 2014), MoPNG stated that *Section 3.2 (ix) of Appendix C to the Accounting Procedure to PSC refers to penalties, liquidated damages and similar payments made by Contractor for non-fulfillment of contractual obligations of the Contractor to third parties*. MoPNG also asked Audit to elucidate whether *Operator's post contractual discussions and agreements with the vendors on cost over-run would not amount to amendment to the original vendor-contracts and whether such amendments were not at arms' length. Further, it mentioned that the conclusion that payment was not in consonance with contractual terms needs to be elaborated in the light of the Operator's agreement with the vendor to modify the original terms and conditions of contract with the vendor.*

2.7.1.1.16. In this regard, Audit observed that Section 3.2 (ix) covers all payments made by the Operator to vendors/third parties on account of non-fulfillment of contractual obligations.

2.7.1.1.17. Operator was requested to provide the details of the exact amounts paid and payable to AMC on this account, however, specific reply giving exact amount paid/payable against the total approximate amount of Euro 200 million was not provided.

2.7.1.1.18. Audit has not commented on commercial, operational or technical performance of the Contractor. It is once again clarified that the audit scope in respect of Operators' records covered financial and propriety audit. As one of the objectives of Audit was also to examine what was permitted and what was not permitted as per rules, Audit objected to these payments as the same were not in line with the contractual provisions.

2.7.1.1.19. Regarding Operator's reply that the change clause in the contract is provided to address issues related to changes post award and the Contractor exercised due diligence in finalizing the changes to the contract, Audit observed that the reasons such as delay in providing FIMs, the completed wells and access to CRP by Operator to AMC; intrusions by fishing boats, suspension of work due to DGS circular etc. for which the Operator had made the excess payment are not covered under the provisions of the clause 'change in contract price' also.

2.7.1.1.20. Thus, in Audit opinion these concessions granted by the Operator to the AMC:

- 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*".

2.7.1.1.21. Therefore, the amount paid/to be paid to the AMC towards the additional resources against the estimated amount of approximately Euro 200 million should not be allowable for cost recovery.

2.7.1.2 Contract for chartering FPSO

The Operator entered (09 May 2007) into an agreement with M/s. Aker Contracting FP AS, Norway (ACFP / vendor) for chartering of a Floating Production, Storage and Offloading (FPSO) facility on lease rental basis for extraction, production, storage and offloading of oil & gas from MA oilfield, from the date of first production of oil (DFPO) for 3650 days @ US$ 294580 per day. After signing the agreement, while FPSO was under construction by the vendor, the Operator issued a Change Order on 27 July 2008 and whereby the following amendments were made in the contract as discussed below:

2.7.1.2.1. Extension of Dry Docking[52] life

2.7.1.2.1.1. Review of the documents in connection with charter hiring and use of the FPSO revealed, as shown in detail below, that ten years was the period for which the FPSO would be required and leased.

- The approved Development Plan for MA oilfield indicates eleven years project life and production profile.
- Request for Proposal (RFP) issued (September 2006) for chartering of FPSO provided for a residual life for ten years.
- Scope of work of the agreement stipulates that during the charter period, *i.e.* for ten years, no dry-docking shall be required.
- Clause 2.2 of the agreement stipulates that the initial charter period would be for 1825 days or 2555 days or 3650 days from the DFPO, i.e. as such the maximum period of the agreement would be ten years.

2.7.1.2.1.2. Audit observed that within a short period (four months – September 2007) of time from the date of signing the agreement, the Operator requested the 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 to the vendor.

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[52] *Dry docking is a term used for repairs or when a ship is taken to the service yard so that the submerged portions of the hull can be cleaned or inspected.*

2.7.1.2.1.3. The Operator in its reply to Audit (February / March 2014) and to MoPNG (June 2014) stated that

- *"Upon arrival of tanker in the yard for conversion, a thorough inspection of the hull was undertaken. Based on the condition of hull and assessment of the fatigue life, the Operator explored the possibility of extension of 'no dry dock' period from 10 years to approximately 12 years and after examining the matter, the FPSO contractor* (vendor) *informed that the field life of FPSO without dry docking could be extended from 10 years to 15 years by undertaking measures such as increased renewal program, increased redundancy and increased scope of coating & steel.*
- *The extension of field life without dry-docking was proposed from 10 years to 15 years considering that the renewal surveys by classification society are undertaken every 5 years. Normally, inspection of the hull is required to be carried out in a dry dock. However, the requirement of dry-docking can be exempted based on the condition of FPSO hull and upon its meeting the conditions imposed by the classification society. Thus, for extension of field life without dry-docking beyond 10 years, the FPSO was to be made fit for the second renewal due in 10th year and thereafter FPSO could remain in the field for another 5 years.*
- *Stipulating dry docking life of 15 years could, however, result in poorer response to the RFP as very limited number of hulls would be in a position to meet this criterion.*
- *The works required to meet the said extension of field life without dry docking would have entailed cost even if it was envisaged at the RFP stage and Contractor had to pay for the same. In any case, Contractor has paid the actual cost for extending the dry dock life and also not paid any mark-up on the cost.*
- *RIL considers that the pre-investment in the extension of dry docking life was a commercially sound as well as the most optimal decision since it not only avoided the cost of increased works that would have been required at the time of second renewal viz. voyage costs, dry dock charges, safe shutdown and restart expenses in the tenth year but also avoided prolonged field shut down which would have carried with it the risk of losing some wells in fag end of field".*

2.7.1.2.1.4. The Operator further stated during the Exit Conference (July 2014) that *the decision was taken to avoid:*

- *Interruption in production and closure of field for at least 8 weeks during the Dry Dock period (on account of disconnections, Demob, Dry Dock, Mob, Reconnections) at the end of 10 years.*
- *Additional cost due to increased scope of work, inflation, mob/demob for dry docking.*
- *Potential loss in reserves due to uncertainty about revival of wells after closure of the field for Dry Docking at the tail end of field life.*

- *Loss in value due to deferment of production.*

It further stated in a letter dated 23 July 2014 that *the total impact of the above on NPV basis works out to $ 27.2 million as against the actual expenditure of $ 17.36 million.*

2.7.1.2.1.5. Audit does not agree with the Operator's reply in view of the following:

- As per the agreement, the maximum initial charter period of FPSO is 3650 days and the Operator has yet to renew the agreement after September 2018. As such, the extension of dry-docking life from 10 to 15 years has no relevance until the agreement gets extended with the vendor beyond ten years. In fact, the extension of dry-docking may not result in any expected benefit till the contract gets extension of 15 years.
- The Operator has assumed that they would get a poorer response to the RFP had they indicated a dry-docking life of 15 years. It is interesting to note that, in the present case, out of eight bidders who finally responded to the RFP in October/ November 2006, the Operator had evaluated only one party viz. ACFP, as technically qualified. Hence, poor response was not considered as constraint for decision making by the Operator[53].
- The Charter Period as per the agreement of the FPSO is upto a maximum duration of ten years from the DFPO. Therefore, the pre-investment argument or the perceived benefit for extension of dry-docking life has no meaning since the charter period remains only upto September 2018.
- As regards, the Operator's statement of 23 July 2014 that *"total impact of the above on NPV basis works out to US$ 27.2 million"* no such analysis was actually done by the Operator while taking the decision of extending the dry docking life at the cost of US$ 17.36 million. Such analysis and arguments supporting it on file was neither found on record/documents produced to Audit nor was ever referred to or supplied as part of any of the various responses given by the Operator even until June 2014. Therefore, the new argument of NPV calculation is clearly an afterthought at the end of Audit and is not sustainable.
- In fact, the Operator cannot get any of the expected benefits from avoiding various types of potential costs and losses (estimated by the Operator now in July 2014 as: costs due to dry dock of US$ 54.4 million and production loss of US$ 15.8 million etc. leading to NPV calculation of US$ 27.2 million) until and unless the contract gets extension for 15 years. Further, the basis for such estimates was also not clear.

2.7.1.2.1.6. In view of above, Audit opines that extension of dry-docking period from 10 to 15 years, while keeping the FPSO charter period to 10 years, led to higher cost recovery and adversely affected GoI's share of PP.

2.7.1.2.1.7. Audit, therefore, recommends that the cost recovery of US$ 17.36 million may be disallowed.

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[53] *Audit findings on the deficiencies in the award process are contained in Audit Report No. 19 of 2011-12.*

2.7.1.2.2. Increased cost for expediting deliveries and early mobilization of commissioning team and extension of date of first production of oil and gas

2.7.1.2.2.1. At the time of issue of RFP for FPSO, one of the eligibility conditions insisted upon by the Operator was that the DFPO be on or before 15 February 2008. This condition was, however, changed and the final agreement stipulated[54] that the DFPO could be between 7 April 2008 and 27 April 2008.

2.7.1.2.2.2. By October 2007 itself, the Operator was aware that the vendor would be unable to comply with the DFPO of April 2008 and that the DFPO may be potentially delayed upto March 2009. Subsequently, through a change order, the agreement was amended and the DFPO was further extended till 30 September 2008.

2.7.1.2.2.3. The vendor also communicated to the Operator that the work could be expedited and delivery dates expedited by putting in place measures which would have cost consequences. Therefore, the vendor requested Operator to contribute towards these cost consequences. The Operator, as per changed order, agreed (July 2008) to compensate the vendor:

- By US$ 15 million for mobilizing its commissioning team along with members of operations and maintenance contractor (vendor) and representatives of major vendors four months prior to Sailaway[55] date of the FPSO; and
- By a one-time compensation of US$ 30 million or 50 *per cent* of the increased cost, whichever is lower, on account of expediting deliveries of topside modules, increasing productivity at builder's conversion yard and timely installation of buoy and moorings.

2.7.1.2.2.4. In this regard, Audit observed that

- At the time of the change order in July 2008, the Operator was well aware that the MC had approved the FDP in April 2008 with DFPO on or before June 2009. In fact, the Operator, while submitting the MA FDP had itself proposed that *"the commissioning of facilities is expected by Q1 2009 in order to be ready for production"*. Therefore, there was no necessity for expediting deliveries.
- Clause 3.4 of the Agreement stipulates that the compensation payable to vendor covers and includes all costs and expenses incurred by vendor to provide or perform all of its obligations under the Contract including without limitation, the work and all procurement, design, modifying, refurbishing, repairing and FPSO, commissioning of the FPSO, transporting and mobilizing the FPSO to the designated location, etc.

[54] *Clause 36.2.*

[55] *Means the date when FPSO will sail from the builder's conversion yard after completion of all works at the conversion yard or other location where the FPSO is located, to the designated location i.e. KG-DWN-98/3 Block.*

contemplated in the contract and there shall not be any other payments to be made by the Operator for vendor's provision or performance of the obligations including the work contemplated by the Contract.

- The vendor was liable to get lease rental for FPSO from DFPO only. Therefore, it was in the interest of the vendor also to achieve DFPO at the earliest.
- There is no provision in the agreement which entitles the vendor to any compensation or incentive for expediting deliveries.
- Despite the vendor being unable to meet its contractual obligations, the Operator re-scheduled the DFPO *between 7 April 2008 and 27 April 2008* to *between 10 September 2008 and 30 September 2008*, without imposing any LD.

Therefore, the compensation of US$ 45 million paid to the vendor for early mobilization of the vendor's commissioning team and expediting deliveries of top side modules etc. was not justified.

2.7.1.2.2.5. The Operator in its reply to Audit (February / March 2014) and to MoPNG (June 2014) stated that

- *"Target dates being natural pressure points as a conscientious Contractor can hardly be faulted for making all efforts to achieve first production of oil ahead of the target given by MC & attempting to achieve the overarching aim of the PSC to develop petroleum resources with the utmost expedition.*
- *As a complex project the execution of MA field development, the execution of all the contracts*[56]*was interlinked and involved significant interfaces involving technical compatibility of disparate individual designs at diverse manufacturing locations and scheduling of installation & logistic activities in synchronization with deliverables/ deliveries under each of several separate contracts, etc. Delay in execution of one aspect in a contract could have had a cascading impact on the schedule and eventually resulted in far greater additional expenditure under other contracts.*
- *Efforts for early completion were necessary for avoiding infructuous expenditure on account of idling of marine spread for installation of subsea facilities and remobilization of resources. Had RIL not entered in dialogue with FPSO contractor* (vendor) *and persisted with enforcing the available contractual remedy in terms of levy of the liquidated damages, the delays arising for execution of FPSO contract would not only have resulted in delayed production from the field but may also have resulted in claims from the other contractors* (vendor).
- *In the instant case, since the delays could have had serious impact on the whole project. RIL entered into negotiations with the Contractor* (vendor) *to work out the way forward on the basis of reasonable cost sharing and risk reduction. In order to ensure that FPSO contractor* (vendor) *completes the work expeditiously, date of first*

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[56] *Hardware Supply Order, Installation Contracts, FPSO charter and O&M Contract.*

projection of oil was extended while the FPSO contractor (vendor) *was compelled to share the expediting cost equally.*

- *In the interest of the project and based on closer understanding of large number of interfaces involved in the complex subsea development, RIL considered that 'hand-on' involvement of O&M team and the representatives of main packages/ equipment during installation, testing & stage-wise pre-commissioning would greatly benefit the smooth start-up & commissioning of FPSO. Finally, it must be emphasized that under the PSC, RIL has the right to make certain operational, technical and commercial decisions based on the its best judgment and it is not appropriate to second-guess these judgments in hindsight.*
- *As the payments have been made on incurred cost basis, there is no additional expenditure involved. Additionally, there is no violation of the terms of PSC in making payments to expedite the work".*

2.7.1.2.2.6. The reply of the Operator is not acceptable in view of the following reasons:

- The Operator enforced target dates, which could not be adhered to practically and had to be extended.
- The vendor in its bid had informed that they would provide their operation and maintenance commissioning team for carrying out the operations preparations as well as assistance for commissioning activities *four to eight weeks* prior to the planned sail away of the FPSO from the yard. However, the Operator, after signing of the agreement, insisted that the O&M commissioning team and representatives of main packages / equipment should be available four months prior to the Sailaway date. Had the Operator considered the issue of time-period of four months at the time of finalising of the agreement then the expenditure of US$ 15 million could have been avoided.
- The delays were due to the vendor's constraints with sub-vendors who were ready to supply modules / equipment with increased compensation / incentives, constraints of work force capacity at the Shipyard and with other sub-vendors for not providing vessels for installation activities.
- The technical bid of the vendor was accepted by the Operator since the vendor accepted the Operator deployment schedule of DFPO, i.e. 15 February 2008. Therefore, it was the responsibility of the vendor to adhere to the time schedule informed to the Operator without any additional costs as per the terms of the agreement. In fact, the Operator had reiterated (September 2007) to the vendor that it was "*AFP's responsibility to maintain the schedule*".
- There is no rationale in advancing the DFPO approved by the MC, by way of incurring US$ 30 million on account of compensation / incentives to sub-vendors for earlier completion of work.

- PSC stipulates that petroleum resources be developed with the utmost expedition. However, no PSC provision imply that the Operator compensate vendors by incentives in order to complete their contractual obligations / work.

2.7.1.2.2.7. In view of the above, Audit recommends that the cost recovery of US$ 45 million incurred by the Operator on account of compensation / incentives to sub-vendors may be disallowed.

2.7.1.2.3. Fabrication and installation of living quarters

2.7.1.2.3.1. As per Clause 6 (e) - Other facilities of the Exhibit-B, Part-I of the agreement relating to functional requirements in FPSO stipulates that the general facilities / requirement for operations include air conditioned living quarters with configuration of one bed, two beds and four beds cabins to accommodate 104 people. The contract price was based on creation of additional living quarters of 40 beds and re-use on an "*as is*" basis of 64 existing living quarters on the FPSO with minimum refurbishment.

2.7.1.2.3.2. The vendor, however, on the request of the Operator, undertook extensive refurbishment and upgradation of the 64 existing living quarters. Such refurbishment also necessitated dismantling of the existing HVAC installation with modification and re-design. These modifications resulted in change orders to the contract leading to payment by the Operator of an additional compensation of US$ 15 million in two installments of US$ 8.20 million and US$ 6.80 million in November / December 2008.

2.7.1.2.3.3. The Operator justified (February / March 2014) the extensive refurbishment on the grounds that "*the personnel working offshore are subjected to hard life and harsh working conditions. The conditions on a floating offshore structure, which is subjected to continuous roll, pitch and heave, are more severe. Provision of upgraded and extensively refurbished living quarters not only mitigates some of the hardships of personnel working on FPSO but also improves productivity, safety and alertness (e.g. better rest during off duty hours, improved morale, personnel retention, etc.). HVAC for living quarters on offshore vessels is not a luxury but an essential requirement for the operating personnel to work efficiently. The operational decision to upgrade and refurbish the living quarters for such personnel was taken in the overall interest of the project*".

2.7.1.2.3.4. The Operator in its reply to MoPNG (June 2014) further stated that "*the provision and consideration of purchase option of FPSO was consistent with the approved Development Plan. Although purchase option of FPSO has not been exercised so far, the Operator cannot be penalized for taking decisions in line with the approved Development Plan and in the best interest of the field development*".

2.7.1.2.3.5. Audit objection is not to deprive better facilities to the personnel. It was the responsibility of the FPSO's vendor to depute personnel on the FPSO. Audit, noted that the existing design with additional 40 quarters had met the requirements of the FPSO Charter Contract. Besides, the harsh working conditions were known to the Operator at the time of procuring the FPSO and the requirements ought to have been finalised at that time.

2.7.1.2.3.6. As per the approved development plan for MA field the development budget included the purchase cost of FPSO as US$ 733 million, but instead, the Operator chartered the FPSO. Audit noted that the Operator was guided (vide its note dated 3/09/2007) in the decision of extensive refurbishment of the existing quarters by the intention to exercise its option to purchase the FPSO at any time during the charter period. The Operator has not exercised the purchase option till June 2014, i.e. after lapse of more than four years of production.

2.7.1.2.3.7. In view of the above facts, Audit considers that refurbishment of the existing living quarters and fabrication and installation of additional living quarters led to avoidable higher cost recovery and therefore, Audit recommends that the cost recovery of US$ 15 million may be disallowed.

2.7.2 Irregular payments

2.7.2.1 Construction of OT INR 22.7 million to M/s Larsen & Toubro (L&T) Ltd

2.7.2.1.1. The contract for construction of OT was awarded on cost-plus basis to L&T Ltd (vendor) on 18 October 2006. As per the original contractual provisions[57], *no compensation is payable to the vendor on account of the Plant and Equipment (P&E) provided by the Operator either owned or hired in the case of vendor being unable to mobilize the P&E.*

2.7.2.1.2. However, on 12 February 2008 the said clause was amended to exclude 450MT / 600MT cranes from its ambit. Resultantly, despite the fact that these cranes were hired by the Operator and the vendor had not incurred any expenditure on hiring of these cranes, the Operator had to pay an amount of INR 22.7 million as compensation charges to the vendor, which resulted in excess booking and should not form part of cost recovery. Further, the approval of the OC in respect of the said amendment to the contract, which caused additional burden on the Operator and the cost recovery, was not taken.

2.7.2.1.3. The Operator in its reply, *inter alia*, contended (January 2014) that

- *During the hiring process, the suppliers of the said cranes were reluctant to accept the contract through L&T Ltd. due to peak demand of such cranes and possible delays in payments if routed through L&T Ltd.*
- *Due to shortage of such cranes in the market and reluctance from the crane suppliers to supply through L&T Ltd., the Operator had to hire the cranes directly.*
- *L&T Ltd. informed the Operator that top up compensation was payable by the Operator like other P&M equipments supplied by L&T Ltd.*

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[57] *Clause 3.L of the Exhibit 'C' (Price Schedule) of the Contract.*

- *As these cranes require a lot of handling by L&T Ltd., the Operator was justified in the payment of compensation to the vendor.*

2.7.2.1.4. The Operator in its reply to MoPNG (June 2014) again contended that *"as handling of these cranes is no different from other P&M Equipment handled by L&T for the project, the top-up compensation shall be payable similar to other P&M equipment. Additionally there is no violation of the terms of PSC in making payments".*

2.7.2.1.5. The reply of the Operator has to be viewed in the light of the fact that

- The scarcity of cranes in the market or reluctance of suppliers to deal with L&T cannot be a justification for amending the contract to exclude cranes and pay additional amount to L&T, when the principle for the original clause was that *no compensation is payable to the vendor for Plant and Equipment provided by the Operator in the case of vendor being unable to mobilize it,* i.e. regardless of the reasons for his inability to mobilize the P&E.
- In terms of Clause 2.1 of the Exhibit 'C' (Price Schedule) of the Contract the vendor is already being paid for all the manpower utilized (i.e. the cost of the manpower plus 25 *per cent* compensation) by it in the project. Therefore, there was no justification in payment of any additional compensation in respect of P&E hired by the Operator on the ground that the *cranes require lot of support while handling the operations like assembly/disassembly and routine maintenance*.
- Further, the Objectives in Appendix F (to the PSC) – Procedure for Acquisition of Goods and Services, inter alia, provides that *"The Objectives of these procedures are to (a) ensure the goods and services acquired by the Operator for the carrying out of the Petroleum Operations are acquired at the optimum cost ……..".* Any contractual clause which results in any additional benefit to a vendor violates the objective of 'optimum cost' laid down in the Appendix 'F' of the PSC.

Thus, the cost recovery of the additional payment of INR 22.70 million made to the vendor as compensation in respect of 450 MT /600 MT cranes hired by the Operator may be disallowed.

2.7.2.2 Payment of INR 1110.90 million as compensation on Free Issue Material

2.7.2.2.1. The Operator had awarded four contracts relating to construction of OT, construction of Jetty and Infrastructure facilities near the OT on cost-plus basis to L&T Ltd and M/s AFCONS Infrastructure Ltd (AI Ltd) as detailed below:

Table 13 : Award of contracts

S. No	Contract details	Vendor	Date of signing of the Agreement
1	Construction of OT and associated facilities	L&T Ltd	18 October 2006
2	Construction of OT at Gadimoga	AI Ltd	28 December 2007
3	Development of Infrastructure at Vakalapudi	L&T Ltd	24 December 2007
4	Construction of Jetty at Yanam	AI Ltd	13 October 2006

2.7.2.2.2. In general, these cost-plus contracts provided for 'payment of compensation at a fixed rate in addition to the cost incurred by the vendor for purchase or hire of material, supplies, manpower, etc. But, the contracts also contained provision of FIMs which were to be arranged by the Operator at its own cost. Various clauses of the contract, therefore, excluded FIMs such as Plant and Equipment hired by the Operator, free issue instrumentation bulks / electrical bulks / pipe fitting bulks etc., other than civil bulks such as cement, steel, reinforcing bars etc. (Clause 3L of the Exhibit 'C' of Price Schedule) and High Speed Diesel (HSD) (Sub-clause 2.4 of the Exhibit 'C' of Price Schedule) supplied by the Operator, from the purview of payment of compensation to the vendor.

2.7.2.2.3. Audit, however, observed that contrary to the above concept of payment of compensation to the vendor only on the 'cost' incurred by it, the above-mentioned contracts also provided for payment of compensation to the vendor as a percentage of the value of FIMs of some categories supplied by the Operator such as cement, steel, (referred to as 'category-1 items' in the contract) sand, aggregate, GI Pipes etc. (referred to as 'other than category-1 items' in the contract) The Operator incurred an expenditure of INR 1110.90 million on payment of compensation for the FIMs supplied by the Operator to the vendors as below:

Table 14 : FIM supplied

S.No	Contract details	Vendor	Compensation Paid on FIMs (INR in million)
1	Construction of OT and associated facilities	L&T Ltd	854.70
2	Construction of OT at Gadimoga	AI Ltd	180.00
3	Development of Infrastructure at Vakalapudi	L&T Ltd	56.00
4	Construction of Jetty at Yanam	AI Ltd	20.20
	TOTAL		1110.90

2.7.2.2.4. Audit further observed that the clause stipulating '*payment of compensation at a fixed rate in addition to the cost incurred by the Contractor* (vendor)' also covered all the labour engaged (directly or through sub-vendor).

2.7.2.2.5. The Operator, however, contended (January 2014) that *category-1 items and other than category-1 items were not capital items and these items related to day to day construction materials which require project execution skills, planning and co-ordination to meet construction schedule.* It was, further, contended that *if procurement of these items were kept in the Contractors* (vendor) *scope directly then this would have resulted in double taxation with respect to VAT and Service Tax and increased compensation on this account.* It was also clarified that *as HSD was directly handled and supplied by the Operator to the Contractor* (vendor) *and as there were no additional efforts put in by the Contractor* (vendor) *on this, no compensation was paid to them*. The Operator in its reply to MoPNG (June 2014) reiterated that *"such material is classified as 'Project capital material' which requires detailed engineering skills for design, engineering & procurement which involves significant role of Engineering Consultant as well for issue Material requisition, bid evaluation and technical clarifications and recommendation before carrying out procurement*".

2.7.2.2.6. During the Exit Conference (July 2014), the Operator further contended that *"Reputed construction contractors for Process Plants generally take up turnkey contracts or entire construction including supply of materials. Accordingly mark-up is charged on the total construction cost including materials"* and that *"In order to incentivize the contractors to bid for supply of labour & provision of construction equipment contract, Operator had to agree for a reasonable mark-up on FIMs".*

2.7.2.2.7. The reply of the Operator has to be viewed in the light of fact that

- In respect of all FIMs, the work was to be done or material was to be arranged by the Operator at its own cost. Consequently, the vendor was not incurring any expenditure on such items. The vendor was expected to utilize those materials and do some value addition to it by utilizing / engaging its manpower. Compensation for costs incurred on account of such manpower engaged by the vendor was already provided for in the contracts (Sub-clause 2.1 of the Exhibit 'C' of the Price Schedule). Thus, the vendor was, as such, being compensated for the cost incurred by it on all the manpower utilized in the project. Therefore, there was no justification of payment of any additional mark-up on the ground that such items involve "significant role of Engineering Consultant". Moreover, the Objectives in Appendix F (to the PSC) – Procedure for Acquisition of Goods and Services, inter alia, provides that *"The Objectives of these procedures are to (a) ensure the goods and services acquired by the Operator for the carrying out of the Petroleum Operations are acquired at the optimum cost ……..".* Contractual clauses which are made to incentivise the vendor on the pretext that the vendors *generally take up entire construction including supply of materials and that there was a need to incentivise such vendors to bid for supply of labour & provision of construction equipment contract* and thus result in additional benefits to the vendor, deviate from the objective of 'optimum cost' laid down in the Appendix 'F' of the PSC.

2.7.2.2.8. Therefore, payment of markup compensation in respect of FIMs of category-1 and other than category-1, on the ground that these materials required additional efforts for its management etc. is not tenable and hence, the cost recovery of amount of INR 1110.90 million may be disallowed.

2.7.3 Improper allocation of expenditure on risk advisory services resulting in excess cost recovery

2.7.3.1. The Operator placed (15 January 2009) a Work Order[58] on nomination basis on M/s. HSBC Insurance Brokers Ltd (vendor) for risk advisory services at a cost of US$ 1.2 million. Prior to placement of the work order, the Operator and the vendor signed (28 August 2008) a Memorandum of Understanding (MoU) detailing the outline principles of the service agreement. The scope of the service agreement, as detailed in the MoU, encompassed all RIL's (Operator) activities within the Exclusive Economic Zone / Continental shelf of India and other named exploratory and developmental sites existent worldwide (as on date). The scope of the work order was on the same lines as defined in the MoU and was effective from 28 September 2008 to 27 September 2009 and M/s. HSBC rendered the services from 28 September 2008 to 28 June 2009 for which payment of US$ 1.2 million was released in December 2009.

2.7.3.2. Audit observed that the entire expenditure of US$ 1.2 million on risk advisory services was booked to KG-DWN-98/3 Block although the scope of the work order indicated that the risk advisory services covered all RIL's (Operator) activities within the Exclusive Economic Zone / Continental shelf of India and other named exploratory and developmental sites existent worldwide (as on date). A review of comprehensive insurance package policy of RIL revealed that the Operator was having 39 licenced blocks (28 in India and 11 outside India). Therefore, Audit is of the view that allocating the entire expenditure, on account of risk advisory services, to only one block, i.e. KG-DWN-98/3 is not in order.

2.7.3.3. The Operator in its reply (January 2014 / July 2014) stated that

1. *Year 2008 – 2009 was critical from an insurance perspective as during this period the D1-D3 and MA oilfields in the KDG6 Block were moving from the development stage to the operation stage. Accordingly, RIL awarded a contract to M/s HSBC for the provision of specialized insurance services.*
2. *This was critical as the transition from the Construction All Risk policy to the Operational policy had to be conducted in a smooth and efficient manner whilst ensuring that there were no gaps in the coverage. This was all more critical as the facilities were being commissioned and going operational in a phased manner.*
3. *Although the contract with M/s HSBC was an open ended contract covering RIL's activities within the Exclusive Economic Zone/Continental Shelf of India and other named exploratory and developmental sites worldwide, it should be noted that the*

[58] *No.038/3679665.*

work performed (i.e, the provision of specialized insurance services) was limited to the KG-D6 Block and therefore the payments under this contract have been booked under KGD6.

2.7.3.4. However, in Audit opinion, the Operator's explanation is not acceptable since the work order for insurance advisory services covered Operator's activities across 39 blocks world-wide. As such the expenditure incurred against the work order should have been allocated across all 39 blocks. Further, if the Operator had wanted the services exclusively for KG-DWN-98/3 Block, it should have specifically indicated the same in the RFQ, which it did not do. Similarly, the vendor while submitting the quotes also did not specifically indicate either block-wise rates or that the rates were exclusively for KG-DWN-98/3 Block. The Work Order, issued in January 2009, did not indicate that the service was to be performed exclusively for KG-DWN-98/3 Block.

2.7.3.5. Non-allocation of the expenditure to other blocks has resulted in excess booking of cost recovery by US$ 1.17 million in the year 2008-09 in KG-DWN-98/3 Block and, hence, should be disallowed.

2.7.4 Classification of Start-up and Production Bonuses as part of recoverable costs

2.7.4.1. During the period 2008-09 to 2009-10, the Operator charged US$ 15.48 million as Long Term Bonus (US$ 1.22 million), Productivity Linked Incentive (US$ 1.78 million), Start-Up Bonus (US$ 9.74 million) and Production Bonus (US$ 2.74 million), paid to its employees in proportion to the number of hours, the employees were engaged in the work relating to KG-DWN-98/3 Block.

2.7.4.2. The Operator has been paying Long Term Bonus (LTB) as a retention bonus and Performance Link Incentive (PLI) to its E&P employees. In addition, the Start-Up and Production Bonuses were given to E&P employees on the occasion of starting first gas production.

2.7.4.3. The PSC allows recovery of eligible costs related to the Contractor's locally recruited employees who are directly engaged in the conduct of Petroleum Operations under the Contract in India and Assigned Personnel. Such costs include salaries, wages, and other costs which are as per the personnel policy and are of a regular nature. In fact payment of 'bonus' has been expressly provided in the PSC only under *Section 3.1.2 (A) (b) Accounting Procedure Appendix - C* for those Assigned Personnel who are directly and necessarily engaged in the conduct of the Petroleum Operations. 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.

2.7.4.4. In reply, the Operator stated (January 2014) that,

"*The provisions of the PSC Section 3.1.2 of Accounting Procedure Appendix - C, make it very clear that the cost of employee benefits, including bonuses are eligible for cost recovery. The* *payment of special incentives/bonuses for project completion or business start-up is a widely recognized and accepted human resources (HR) policy. Whereas the startup bonus was paid to the employees relating to completion of the activities and operationalising the project as a performance bonus. The PSC nowhere stipulates such restrictions and the above opinion of the audit is not in line with the provisions envisaged in Section 3.1.2 of the PSC. The start-up and production bonus was paid to employees as a performance bonus for completion of activities directly concerned with the project. In addition to improving employees morale and productivity, the payment of such incentives to employees is an employees retention tool in minimising the turnover and retaining the trained resources for completion and operationalising the project without resource constraint. It is pertinent to mention here that the New Business Start-up Award was paid linking to the performance rating of the employees."*

2.7.4.5. The Operator in its reply to MoPNG (June 2014) stated that *"periodic review of employee benefits, perks, compensation levels, performance incentives and productivity bonuses are part of the HR best practices in enhancing the performance level of the employees. Hence, the payment of start-up and production bonus is very much covered under employee benefits allowable under Section 3.1.2"*.

2.7.4.6. Audit, however, does not agree with the Operator for the following reasons:

- Audit has not objected to bonuses, *per se*, and has not raised any objection on the payment of Long-Term Bonus and Performance Link Incentive being paid to employees regularly.
- The Operator has been paying salaries and other benefits like Long Term Bonus as a retention bonus and Performance Link Incentive to its E&P employees for improving the morale and productivity and retaining the experienced employees. Hence, to claim that talented and experienced human resources could be retained by paying Start-Up and Production Bonuses does not appear tenable.
- The observation is limited to the provisions of the PSC. The employees of E&P division of the Operator are working as per the agreed terms and conditions of the Company, as per its HR policy, and the compensation is a clearly defined package, and are incurred by the Operator in the conduct of Petroleum Operations pursuant to the PSC. The completion of activities was also not linked to payment of any such Start-Up and Production Bonus.

2.7.4.7. Booking of payment of US$ 12.48 million on Start-Up and Production bonuses to the revenue earned from KG-DWN-98/3 Block is not covered under Section 3.1.2 of Accounting Procedure Appendix - C of PSC and, therefore, should be disallowed from cost recovery.

2.7.5 Award of contract

2.7.5.1 Piece-meal hiring of drilling rig "Deepwater Frontier" from M/s. Transocean – US$ 88.77 million

2.7.5.1.1. The Operator awarded charter hire of an offshore deep water drilling rig to M/s. Transocean Offshore International Ventures Limited (Transocean / vendor) in April 2005 (1st Contract) for the rig "Deepwater Frontier", with the rig deployment program starting from June 2006 for a 24 months period at an operating day rate of US$ 0.32 million per 24 hours.

2.7.5.1.2. In December 2005, seven months after awarding 1st Contract, the Operator observed that availability of Deepwater Drilling Rigs had become scarce and in order to ensure continued availability of rigs beyond 2007, the Operator initiated the tendering process for award of Charter Hiring of offshore deep water drilling rig.

2.7.5.1.3. The Operator, awarded (February 2006) the 2nd Contract again to Transocean for the same rig "Deepwater Frontier" at an operating day rate of US$ 0.48 million per day, for a 36 months firm period commencing from August 2008, i.e. after the expiry of the period for charter-hire under 1st Contract.

2.7.5.1.4. The rig "Deepwater Frontier" completed its contract under the 1st Contract on 31 July 2008 and started the work under the new 2nd Contract on the same day w.e.f 16:30 hrs.

2.7.5.1.5. The Operator contended (January 2014) that *"RIL's commercial decision to enter into a 2-year contract in April 2005 following a competitive tender process and then to subsequently enter into a 3-year contract in February 2006 following a competitive tender process started in December 2005 was based on the information available to it at the time of each contract. RIL was acting in good faith in the best interests of the project and the parties to the PSC*". It further contended that *"An increasing trend in rates in 2004 is not relevant; there was no indication that this would continue over a period of five years. There is, therefore, no basis for CAG's assumption that locking in prices for five years would necessarily have achieved a lower overall spend*". The Operator reiterated its contention in its further reply (April 2014) and also stated that *Audit assumes that the Operator would have been able to fix a five year contract at the same rates as its two year contract, which may not have been the case. The bidder(s) would have definitely bid a much higher day-rate for a five year tender*.

2.7.5.1.6. The Operator's explanations have to be viewed in the context that Audit is not just commenting on the rates but also the following:

- The Operator was to assess the future requirement for drilling of wells keeping in view the FDP approved (November 2004) for D1-D3 fields and plan the deployment of drilling rig(s) accordingly;
- The Operator was already aware of increasing trend of rates based on the RFQ issued in the year 2004 and poor responses received from vendors, for provisioning of rigs;

- The Operator has entered into long-term contracts in case of other rigs. In April 2008 the contract for Rig Dhirubhai Deepwater KG2 (DDKG2) was awarded to Deepwater Pacific Inc. for 5 years at a firm operating day-rate of US$ 0.51 million, which is evidence of the fact that rigs are hired at firm rates for long term contracts.

2.7.5.1.7. The Operator in its reply to MoPNG (June 2014) contended that *approval for a critical cog i.e. laying of pipelines to evacuate & market gas was delayed by the MoPNG by 17 months which unfortunately delayed the project. Considering the aforesaid uncertainty in execution of IDP, there is no rationale for Contactor to commit Drilling rigs on the basis of IDP.*

2.7.5.1.8. The contentions of the Operator have to be viewed in the light of the following facts:

- The Operator in the previous Audit Report (page 70 of C&AG's Audit Report No. 19 of 2011-12) had admitted that 'post IDP approval, the Operator had initiated work on extensive studies based on additional data generated' and 'during Q4 2004 and Q4 2005, the studies brought out that the reserve base was much higher'. The Operator also contended in the previous Audit Report that *"Geological and reservoir understanding keeps improving as additional well data, reservoir data and production data becomes available; however, investment decisions are still taken on the basis of the then understanding*".

- Thus, the contention of the Operator that there was uncertainty in the execution of IDP is not tenable as the reported delay in timely approval and receipt of statutory clearances relevant to the Project would impact only the time schedule of the IDP and not the "certainty of the execution of IDP".

- Further, from the chronology of events (COE) furnished by the Operator alongwith its reply dated 31 January 2014 to the Audit Observation, it is evident that the process of hiring of deep water rigs was initiated after the submission of the IDP for 34 wells and the 1st Contract was finalised in April 2005. Immediately, after 7 months of finalization of the 1st Contract (i.e. in December 2005), the Operator, reportedly, realised the scarcity of the deep-water rigs and decided to enter into another contract and finalised the 2nd Contract (February 2006). Till the time of entering into the 2nd Contract the number of wells to be drilled remained the same (34) as per IDP (AIDP for 50 wells to be drilled, was submitted only in October 2006). In other words, the drilling prospects were the same during both the 1st Contract and the 2nd Contract. Thus, the contention of the Operator that adequate drilling prospects were not there during the 1st Contract for a long term contract is not tenable.

2.7.5.1.9. Therefore, the fact remains that despite having adequate drilling prospect and keeping in view the poor response received from the vendors for provisioning of the rigs (which was an indication of the scarcity of the deep-water drilling rigs and would have had an adverse impact on the day rates), 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 which resulted in additional expenditure of approximately US$ 88.77 million[59].

2.7.5.2 Hiring of drilling supervisor

2.7.5.2.1. The Operator awarded two contracts to M/s Allomax Associates Ltd (No 050/91082 dated 11 February 2009) and M/s World Wide Worker Technical Services (No.050/94552 dated 13 March 2010) for hiring of personnel for drilling services. Such personnel included Senior drilling supervisor for which the rates were US$ 1460 and US$ 1600 per day respectively in the two contracts. These contracts were finalized after following the due procedure of competitive bidding process. Therefore, the finalized rates can be taken as true market rates.

2.7.5.2.2. Audit observed that a combined work order No.OG3/85986 dated 20 June 2007 for the hiring of drilling supervisor (SL.No.10 item code-3109712- 0322) for three[60] Blocks was placed on Richard Brent Kopulos (vendor), Australia at a total value of US$ 0.31 million (day rate of US$ 1848) for the period from 1 July 2007 to 30 June 2008 on nomination basis. The contract was extended twice, as below:

a) Vide W.O.No.OG3/3661008 dated 24 May 2008 for a value of AUD 0.49 million (day rate of AUD 2525) for the period 1 July 2008 to 30 June 2009; and

b) Vide W.O.No.049/92842 dated 15 July 2009 for a value of AUD 0.50 million (day rate of AUD 2525) for the period 1 July 2009 to 30 June 2010.

2.7.5.2.3. These extensions were approved by OC on 10 April 2008 and 25 May 2009 respectively.

Since a competitive process was not followed in the extension of this contract, the rate allowed to the vendor was higher than what would have emerged through market discovery of rates for similar nature of work and job responsibility.

2.7.5.2.4. The difference in rates resulted in extra payment of US$ 0.15 million (*Annexure 5*) being the higher rates allowed to the vendor over the prevailing market rates was uncalled for. Consequently, cost recovery has been over-booked to the extent of US$ 0.15 million.

2.7.5.2.5. The Operator in its reply (January 2014) stated that it, "*takes a two pronged strategy for hiring of senior drilling supervisors to ensure continuous availability of*

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59 (i) Approved Amount for Contract 'B' for utilizing the Rig during the period August 2008 to November 2010: US$ 303.63 million, (ii) Payment that would have been made (for the above period) had rates of Contract 'A' followed: US$ 203.78 million (calculation made on the basis of the fact that the various Day Rates had increased uniformly @ 49%), (iii) Difference: US$ 99.85. However, as the percentage utilization of Rig DWF for KG-DWN-98/3 Block was only 88.90, the difference attributable to this block would be: US$ 88.77 million.

60 KG-DWN-98/3 (KG-D6), MN-DWN-2003/1 (MNV-4) and NEC-OSN-97/2 (NEC25).

competent resources, and also resort to nomination or extension of existing contracts".

2.7.5.2.6. The reply is not tenable since all the agencies / vendors were contractually liable to provide the competent personnel as per the terms and conditions of the contract. Allowing higher rates on nomination basis is not justified.

2.7.5.2.7. The Operator in its reply to MoPNG (June 2014) also stated that *"the purchase procedure ROG-GPP-004 Clause 8.0 (4) (page 9) approved by MC permits Contractor to award work on Single/ Nomination basis for services of special nature. The rates for such specialized services like deep-water drilling supervisor depend on demand and supply"*.

2.7.5.2.8. It may be noted that in this case Audit has not questioned the award on single/nomination basis. However, since services of a similar nature have also been contracted by the Operator during the same period at lower rates, in Audit opinion, the extra expenditure of US$ 0.15 million is not liable for cost recovery.

2.7.6 Additional payment for mandatory contractual work

2.7.6.1 Bonus paid for time saved during rig movement

2.7.6.1.1. The Operator entered into two contracts (OG3/3597423 dated 24 February 2006 and OG3/3587422 dated 29 October 2007) with M/s Transocean for hiring of deep water drilling rigs Deepwater Frontier (DWF) and Discoverer 534 (D534) respectively. Clause 20 of Exhibit A – Scope of work of the contracts states that –

"…… Contractor (vendor) *shall be responsible for in-field movement of the Rig. Depending upon the weather conditions and Drilling Rig capability, Contractor* (vendor) *shall ensure in-field Rig movement with BOP* (Blow Out Preventor) *and Marine riser in hanging position and drill pipe / drill collar stands racked in derrick"*.

2.7.6.1.2. A review of the invoices for the above two contracts revealed that the Operator paid US$ 1.88 million and US$ 0.95 million respectively for DWF and D534 as bonus for time saved during the rig movement between wells with hanging Blow Out Preventor (BOP). Audit observed that rig move with hanging BOP was mandatory as per the above cited clause. As such, the payment of bonus for rig movement with hanging BOP was not justified and resulted in additional expenditure of US$ 2.83 million.

2.7.6.1.3. The Operator in its reply to Audit (January 2014) and to MoPNG (June 2014) stated that

- *The in-field rig movement with BOP in hanging position stipulated in Clause no.B.20 of Exhibit A - Scope of Work is dependent on the weather conditions and Drilling Rig capability. This clause is a functional requirement, since the weather conditions and other parameters are not known/ available upfront and a decision in this regard is taken on case by case basis considering the weather conditions and other parameters,* *bathymetry, duration of voyage etc. There is no absolute obligation to carry out in-field rig movement with BOP in hanging position as the Audit Team supposes.*

- *Generally the industry practice for undertaking the in-field rig movement with BOP in hanging position (subject to weather and other technical conditions) is when the Rig movement (distance) is short and each rig move with BOP suspended is evaluated and carried out only if the technical conditions can be met.*
- *As per Contract, Contractor* (vendor) *is entitled to performance incentive in accordance with Clause no.E.2 of Exhibit A - Scope of Work for completing the wells ahead of the target number of days.*
- *As per the contracts, there was no fixed bonus scheme and the incentive scheme was to be mutually agreed and payment modalities for payment of incentive amount were to be separately worked out. This was the basis and intention behind Contractors stipulation while agreeing to the bonus payments that "this is a one-off agreement and will not be cited as precedence for future operations".*
- *Audit's view that any bonus payment should have taken into account the sum total of time saved/excess time taken for all the operational activities for completion of well rather than a single activity of rig movement between well sites is not tenable since day rate is payable during rig movement i.e, for total time of journey between wells and any time saved on this account is also to the benefit of the Contractor.*

2.7.6.1.4. The reply of the Operator given in January 2014 as well as in June 2014 is not tenable in view of the following:

- In-field rig movement with BOP in hanging position depending on weather condition was a standard condition included in the contract based on the capability of the rig. The Operator's contention that the Audit team has supposed in-field rig movement with BOP in hanging position as absolute obligation is also not factually correct since Audit has not objected to rig movements without hanging BOP where weather conditions have not permitted rig movement with hanging BOP. Rather, the Audit objection is on bonus payment for rig move with hanging BOP which was a standard condition as per scope of work.
- The Operator's contention that the vendor was paid bonus for rig movement with hanging BOP in accordance with Clause no.E.2 of Exhibit A - Scope of Work for completing the well ahead of the target number of days is not tenable since as per the Clause any bonus payment should have taken into account the sum total of time saved/excess time taken for all the operational activities for completion of well rather than a single activity of rig movement between well sites.
- Also, while approving bonus payment, the Operator has neither quoted the cited contract clause nor has a comparison been made between targets fixed, if any, as per

the cited clause and actual performance of the rig. In fact, the bonus payments have been termed as a one-off arrangement and not to be cited as precedence for future operations.

- This implies that bonus payments are not as per the terms and conditions of the contract for hiring of rigs.

2.7.6.1.5. Since the bonus payments were not covered under the terms and conditions of the contracts, the additional expenditure of US$ 2.83 million should not be allowable for cost recovery.

2.7.6.2 Payment of Uptime Bonus for chartering FPSO

2.7.6.2.1. The Operator entered (09 May 2007) into an agreement with M/s. Aker Contracting FP AS, Norway (ACFP / vendor) for chartering of the FPSO facility on lease rental basis. The Operator also entered (15 October 2007) into an agreement with M/s. Aker Borgestad Operations AS (ABO) for operation and maintenance of its FPSO facility, Operator's equipment and for operation of subsea equipment.

2.7.6.2.2. During the period 2008-09 to 2011-12, both ACFP and ABO were paid Uptime Bonus[61] as per contractual provisions i.e., "*Lease Rental / Operating day rate shall be subject to adjustment for all Downtime (up or down) in the production performance of the FPSO throughout the Charter Period or Operating period*". Till March 2012, the Operator had paid US$ 15.48 million as uptime bonus to ACFP (US$ 13.37 million) and ABO (US$ 2.11 million).

2.7.6.2.3. In Audit opinion, 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, while ACFP is contractually bound to make available FPSO during the charter period, the ABO is contractually bound to ensure availability of the FPSO for not less than 95 *per cent* of each financial year. The operation and maintenance of the FPSO is the responsibility of ABO. Therefore, these bonus payments were made in addition to the normal lease rental day rate of US$ 294580 and an operating day rate of US$ 42789.

2.7.6.2.4. The Operator in its reply (January 2014) stated that

- *"The D-26 (MA) oil, gas and condensate discovery in KG-DWN-98/3 (KG-D6) Block is India's first deep water development (water depth ranging from 1000-1250 meters) with subsea wells connected to a purposed built, state of art dis-connectable turret moored FPSO, which is designed to withstand harsh and cyclonic conditions of the East Coast of India. Operating under these extreme conditions warrant contractual provisions for adjustment of downtime / shutdown, which work as incentive for the*

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[61] *As per Part-1, E-II of Exhibit C - relating to contract price schedule and Contractor's schedule of rates which relates to 'Adjustment of downtime/ shutdown-production performance'.*

FPSO contractors (vendor) *to maintain the FPSO at the highest standards of technical integrity and thus ensure maximization of the its availability. Therefore, it would not be correct to state that uptime bonus give undue benefit to the charter hire and O&M contractors* (vendors)*, as they are contractually bound to make available FPSO and operate and maintain it.*

- *It may also be mentioned that it is standard practice internationally to have such performance incentives in FPSO contracts, especially where a cross-defaulted operation and maintenance ('O&M') contract is in place along with the charter hire contract.*
- *The payment of uptime bonus to the FPSO charter contractor* (vendor) *and O&M contractor* (vendor)*, in addition to the lease rental/ operating day rate is in the best interests of Petroleum Operations to ensure uninterrupted uptime production of oil and gas from the D-26 field".*

2.7.6.2.5. Audit's further response in view of the Operator's replies is as follows:

- As operation of FPSO is continuously dependent on its efficient maintenance and repairs Audit has considered Operator's justification for payment of bonus to ABO. However, Audit does not find any justification for payment of bonus to ACFP who would any way get their daily lease rentals for availability of the FPSO.
- As regards Operator's response about standard practice internationally to have such performance incentives in FPSO contracts, Audit reviewed the FPSO charter hire contract entered into by ONGC with M/s. Forbes Bumi Armada Offshore Limited and found no clause relating to such performance incentives.

2.7.6.2.6. The Operator in its reply to the MoPNG (June 2014) stated that *"incidentally ONGC's track record including charter hire of "FPSO Crystal sea" has nothing to emulate and all payments have been made in line with the signed contract between the Operator and M/s.ACF/ABO".*

2.7.6.2.7. The reply of the Operator is not acceptable as ONGC case was cited by Audit in response to the Operator's statement that *"it is standard practice internationally to have such performance incentives in FPSO contracts".* ONGC is a Maharatna Public Sector Enterprise having overseas operations through its wholly owned subsidiary ONGC Videsh Limited.

2.7.6.2.8. Therefore, compensating ACFP with regard to uptime bonus in addition to the normal lease rental per day has given additional benefit of US$ 13.37 million to ACFP.

2.7.7 Non-enforcement of penal clauses

2.7.7.1 Availability of engine in deepwater drilling rig-Discoverer 534

2.7.7.1.1. Contract No.OG3/3587422 dated 29 October 2005 was entered into with M/s

Transocean Discoverer 534 LLC for hiring of drilling rig Discoverer 534 (D534). The drilling rig D534 arrived on first well location on 18 December 2007 and started preparation to commence the work. On 19 December 2007, a fire was reported in engine No.5 which also caused damage to engine No.6 and the rig became non-operational. Engine No.6 was repaired on 22 December 2007 and put in operation and the rig was also able to commence well related activities from night of 22 December 2007. Engine No.5 was made operational from 15 April 2008.

2.7.7.1.2. Clause C-9.0 of Exhibit C of the contract states that

"For the period of time the Contractor's (vendor) *Equipment as per the Contract are not available on Rig / RIL's Shorebase for which operations are not being suffered at that point of time, RIL shall effect the deduction of 1/60th of the Equipment cost, per day of non-availability, as per invoices furnished by the Contractor* (vendor)*".*

2.7.7.1.3. The non-availability of engine No.5 resulted in short deployment of equipment and Operator was entitled to deduct 1/60th of the equipment cost per day towards non-availability of the equipment for the period of 115 days from 22 December 2007 to 15 April 2008 during which operations did not suffer. However, Audit found that Operator did not enforce any penalty on the vendor. Operator decided to waive this clause on the grounds that a confirmation had been given to the vendor that this clause had never been enforced in the past and was retained in the contract to act as a deterrent.

2.7.7.1.4. In reply to an audit requisition issued to ascertain the cost of equipment, the Operator stated (November 2013) that it does not have a separate figure for cost of engine no.5. It also stated that this event happened around six years ago and D534 is not with the Operator now.

2.7.7.1.5. In Audit view, the contractual provision was introduced as a deterrent. If the Operator had given a confirmation to the vendor that it would not be enforced, then it was meaningless to include / retain it in the contract. To this extent, contract management was deficient. Therefore, Audit feels that reasons given for non-enforcement of clause C-9.0 of Exhibit C are not tenable as the purpose of inclusion of any clause in the contract is to adhere to it strictly. Non-enforcement of the conditions of contract has resulted in non-recovery of per day penalty @ 1/60th of the cost of engine No.5 for a period of seven months.

2.7.7.1.6. Since the Operator did not provide the details of equipment cost, Audit, based on information for rebuilt engine of similar specification[62], worked out the penalty of US$ 0.57 million (cost of the engine no.5 US$ 299,250 x 1/60 x 115 days) recoverable from the vendor.

2.7.7.1.7. The Operator in its reply (January 2014 / July 2014) stated that

[62] *20 Cylinders, 3600 hp @ 900 rpm.*

1. *In the case of short deployment of the Contractor's* (vendor) *Equipment, i.e. if the Contractor's* (vendor) *Equipment is not available on Rig I Operator's Shore-base, for which operations are not being suffered at that point of time, then Operator shall effect the deduction of 1/60th of the Equipment cost, per day of non-availability, as per invoices furnished by the M/s Transocean.*
2. *In the present case, engine no.5 was available on the Rig and the Rig was not shut down nor any operation suspended. Hence the above provisions were not applicable.*
3. *The cost benefit analysis of taking steps to enforce a contractual provision has to be considered before such steps are taken. This involves forming an opinion as to the interpretation of the contractual provision and the potential cost of such action (eg. legal costs, delays, damage to commercial relationship, likelihood of disputes, potential defences, etc.). The Operator's decision was not to try to enforce a penalty against M/s. Transocean. This was a commercial decision taken in response to the circumstances existing at that time.*

2.7.7.1.8. The reply of the Operator is not tenable as:

a) While approving release of payment of retained amount on account of defective engine no.5, the Operator himself has accepted that the instance pertains to short deployment of equipment as per clause no. C 9 of Exhibit C and the Operator can deduct $1/60^{th}$ of the equipment cost towards equipment non-availability.

b) Availability of defective equipment is as good as non-availability of the equipment as defective equipment cannot be put to any use. Moreover, engine no.5 became defective before the completion of mobilization of the rig as is evident from the fact that the Operator had accepted the rig with qualified mobilization.

c) Contractual provisions are incorporated in order to be enforced / implemented. Having incorporated a penal clause in the contract for non-availability of vendor equipment, the Operator should have insisted upon M/s Transocean to provide the cost of major equipment at the time of finalizing contract clauses in order to strictly enforce penal clauses in the contract. Further, if the Operator was concerned about the potential cost of enforcing such contractual provisions, these provisions should not have been included in the contract in the first place. Having included these provisions in the contract, the Operator should have enforced the same.

d) The penalty of US$ 0.57 million has been worked out based on the rate of penalty and number of days of default.

2.7.7.1.9. Audit is of the opinion that additional expenditure of US$ 0.57 million was incurred due to failure of the Operator in enforcing contractual penal provisions resulting in non-recovery from vendor and, hence, should not form part of cost recovery.

2.8 Revenue issues

2.8.1 PSC provisions for valuation and pricing

2.8.1.1. In terms of Article 18.7 of the PSC regarding Domestic Supply, Sale, Disposal and Export of Crude Oil and Condensate, a Crude lifting procedure and Crude sales agreement based on generally acceptable international terms shall be agreed upon by the Contractor with buyer (s) no later than six (6) months or such shorter period as may be mutually agreed between the Contractor and buyer (s) with the consent of GoI prior to the commencement of production in a Field.

2.8.1.2. Article 19.4 of PSC provides that for the purpose of determining price at Arm's Length Sales, the price of the Crude Oil at which sale takes place will generally be based on per Barrel of one or more crude oils which, at the time of calculation, are being freely and actively traded in the international market and are similar in characteristics and quality to the Crude Oil in respect of which the price is being determined, selling price to be ascertained from Platt's Crude Oil Market Wire daily publication ("Platt's"), or the spot market for the same crude oils ascertained in the same manner, whichever price more truly reflects the current value of such crude oils.

2.8.1.3. Further, in terms of Article 19.5 of PSC regarding Valuation of Petroleum, Contractor shall determine the relevant prices in accordance with Article 19 and the calculation, basis of calculation and the price determined shall be supplied to the GoI and shall be subject to agreement by the GoI.

2.8.1.4. The provisions specified for the determination of the price of sales of Crude Oil apply *mutatis mutandis* to Condensates[63].

2.8.2 Selection of marker for Crude Oil and inclusion of composite premium of 2 *per cent* in crude price

2.8.2.1. The production of Crude Oil from MA oilfield commenced in September 2008 and since then it is being supplied to Hindustan Petroleum Corporation Limited (HPCL) and Chennai Petroleum Corporation Limited (CPCL) barring one cargo to Essar Oil Limited (EOL) in May 2010 on the basis of Spot Crude Oil Sales Agreements (COSAs) from time to time.

2.8.2.2. In order to comply with above provisions of PSC and to determine a market discovered price for the sale of Crude, the Contractor followed a competitive bidding process by inviting bids on 12 May 2008 from the prospective buyers *viz.* HPCL, Bharat Petroleum

[63] *As per Article 1.22 of the PSC, "Condensate" means those low vapour pressure hydrocarbons obtained from Natural Gas through condensation or extraction and refers solely to these hydrocarbons that are liquid at normal surface temperature and pressure conditions provided that in the event Condensate is produced from a Development Area and is segregated and transported separately to the Delivery Point, then the provisions of this Contract shall apply to such Condensate as if it were Crude Oil.*

Corporation Limited (BPCL), Indian Oil Corporation Limited (IOCL), MRPL, CPCL and EOL to quote their requirement in terms of quantity and a price based on which the price and quantity were to be finalized.

2.8.2.3. CPCL and HPCL were the only interested buyers and crude price was fixed at a fixed discount of US$ 5.34 / BBL on Bonny Light. This price discovery process was submitted to GoI on 11 July 2008 and 8 September 2008 for its consent / concurrence. However, the GoI has not approved the term contracts till date (December 2013) or the price/pricing formula for the sale of crude. It is being sold on provisional price basis to these buyers under Spot COSAs from time to time under different pricing formulae.

2.8.2.4. Audit observed that in order to fix the price of crude oil as per PSC provisions (Article 19.4), the KG-DWN-98/3 Block crude quality was compared[64] with bench-mark oils such as Tapis, Bonny Light and Dated Brent. RIL adopted Bonny Light as the benchmark, based on negotiations with PSU buyers.

2.8.2.5. Incidentally, M/s Jacobs Consultancy, USA, the Petroleum Planning and Analysis Cell[65] (PPAC) consultant for valuation of PSC Crude Oils, in their report (May 2010) recommended that the pricing for the KG Basin crude oil be linked to 100 *per cent* Tapis crude oil. The quality of KG-DWN-98/3 Block is similar to Tapis and both are Light Sweet crude oils. Further, Tapis is one of the most recognizable benchmark crude oil in the Asia-Pacific region in view of its price transparency and trading volume.

2.8.2.6. Audit observed that different pricing formulae were adopted for the spot cargos sold during the period 2008-09 to 2011-12 as under:

- Fixed differential to Bonny Light monthly average of Bonny Light minus US$ 5.34;
- 5-Cut Wt. based Gross Product Worth (GPW) differential plus a composite premium of 2 *per cent* on Bonny Light;
- Fixed differential to Dated Brent (Average plus US$ 2.11).

2.8.2.7. In fact, Audit noted that crude oil was being supplied to HPCL and CPCL, as per respective COSAs[66], with an additional 2 *per cent* composite premium over Bonny Light to reflect the quality differential between the two crude oils. This was despite the fact that the yield quality has already been factored in the calculation of the GPW differential between KG-DWN-98/3 Block crude and Bonny Light crude oil, by way of deduction. GPW of KG-DWN-98/3 Block crude was less than the Bonny Light Crude Oil and varied from (-) 1.818 to (-) 11.397 (*Annexure 6*) during the period from June 2009 to March 2012. Despite the negative variance, 2 *per cent* composite premium for KG-D6 Crude over Bonny Light was

[64] *As per discussion paper for the meeting dated 13 April 2009 held between RIL and HPCL regarding fixation of crude price.*

[65] *An MoPNG associated office specialized in these matters.*

[66] *Agreement with CPCL dated 5 May 2010 and HPCL dated 14 June 2010.*

also added in the final prices. Financial impact worked out to US$ 30.42 million (*Annexure 7*) being the impact of composite premium for the period June 2009 to March 2012.

2.8.2.8. It was further observed that in earlier COSAs with HPCL (November 2008); CPCL (February 2009); and EOL (April 2010), GPW and composite premium was not considered and sale prices were arrived at on the basis of Bonny Light minus US$ 5.34 /bbl in case of HPCL and CPCL and in the case of EOL, it was Dated Brent plus US$ 2.11 /bbl.

2.8.2.9. The Operator in its reply (January 2014) stated that

- *Initially RIL had proposed Tapis as marker for KG-D6 Crude Oil. However, in interaction with buyers, all buyers unanimously said that Tapis was not an acceptable marker to them as it was too volatile / expensive to the buyers.*
- *Bonny Light is freely traded crude and is considered more transparent in assessment than Tapis, since the volume of Bonny Light crude oil traded in the spot market is much higher. Spot availability of Tapis crude oil is very limited.*
- *Tapis does not mirror the quality of KG-D6 Crude Oil and so a quality differential would have been applicable and would have had to be negotiated between the parties.*
- *Differential or adjustment to the marker crude is to be negotiated between the parties does not mean that the pricing formula lacks transparency. It is industry practice to negotiate a differential or adjustment to the Benchmark crude to reflect factors such as quality. This is recognized in Article 19.4 of the PSC, which refers to an adjustment for "differences in the crude Oil. And the crude oil being compared for quality, transportation costs, delivery time, quantity, payment terms and other contract terms to the extent known and other relevant factors".*
- *No two crude oil can have identical qualities and different grades of crude oil are priced on negotiable differentials to the selected benchmark crude. ..Even if Tapis was accepted as a bench mark crude. ..there would still have been differential in the pricing framework of KG-D6 Crude Oil.*
- *Crude is being sold on Arm's Length terms and the price agreed with HPCL and CPCL, taking into account factors such as quality, etc, as envisaged under the PSC. There are no standard non-negotiable adjustments or price differentials for such factors. The parties necessarily have to negotiate adjustment or price differential in the context of KG D6 Crude Oil being sold.*

2.8.2.10. The reply needs to be viewed in the light of the following:

- The marker of the Crude, *i.e.* Tapis, was changed to Bonny Light / Dated Brent and there was further change in the methodology of calculating the price.

- Negotiation has been provided in Article 19.4.1 to be made in such cases where there is no benchmark crude available to base the price on.
- The buyer (HPCL) had pointed out variations in quality which also had an impact on pricing and final revenue. Subsequently, the issue was settled through a side letter agreement.

2.8.2.11. Audit, therefore, concludes that the pricing mechanism for Crude from MA oilfield needs to be finalized and approved by MoPNG. At present, in the absence of approvals, GoI's contention is that the COSA sales be treated as provisional. However, the Operator is treating the sales as firm and final. No provision has been made for the impact of changes by the GoI. Marker has not been fixed so far.

2.8.2.12. In their reply (June 2014) MoPNG did not give any reason for either the delay in approval or any timeline by which the approval would be given.

2.8.2.13. Further, the Operator in its reply to MoPNG (June 2014) stated that *"it was transparently discussed and agreed with the buyers through an arm's length negation process".* Audit would like to reiterate that it is not the contention of Audit that the sale was not at arm's length or that KG DWN-98/3 crude oil should be sold at price below what the market is willing to pay. Rather, Audit opines that the crude oil should be correctly valued and priced accordingly to this end. The GoI should finalize its views on valuation so that the scope for any ambiguity in pricing is reduced.

2.8.3 Billing and accounting of natural gas

2.8.3.1 Marketing Margin on gas produced and sold

2.8.3.1.1. An EGoM approved the formula / basis for valuation of natural gas from KG-DWN-98/3 Block under Article 21.6.3 of PSC. In line with this approval, the sale price formula for gas at the delivery point at Kakinada is regulated by MoPNG letter No. 0-19025/15/2007-ONG (V) dated 10 October 2007 as under:

SP (US$ / mmbtu) = $2.5 + (CP - 25)^{0.15}$ where,

SP = Sale price in $ / mmbtu (NHV basis) at the delivery point at Kakinada.

CP = Crude price with cap of US$ 60 / barrel.

Accordingly, sale price worked out to US$ 4.20 / mmbtu (with a cap of US$ 60 / barrel).

2.8.3.1.2. MoPNG vide its above mentioned letter had also stated that *"if the actual price at which any supplies made to any consumer happens to be higher than the one arrived at by the methodology, then the higher price shall be taken for purposes of the GoI take for that quantity".*

2.8.3.1.3. A review of records relating to sales of gas revealed that the Operator is charging the Sale Price for gas (as per the Gas Sales Purchase Agreement (GSPA) and invoices) in two components, i.e. Gas Price @ US$ 4.205 mmbtu and Marketing Margin @ 0.135 US$ / mmbtu from its consumers.

2.8.3.1.4. In this connection, it has also been noticed that while computing the PP and Royalty, the Operator is considering the price of US$ 4.205 mmbtu instead of the actual Sales Price of US$ 4.340 mmbtu being charged by him from the consumers. Thus, the revenue earned through marketing margin is not being treated as revenue for the purpose of calculating Cost Recovery, PP and Royalty. The financial impact on Cost Recovery, GoI's Share of PP and Royalty are worked out in Table 15 as under:

Table 15 : Financial impact on Cost Recovery, PP and Royalty

(Amount in US$ million)

Particulars	Year 2009-10	Year 2010-11	Year 2011-12	Year 2012-13	Total
Qty. produced & sold-N Gas (mmbtu)	460,353,175.90 (including 7,299,359.39 for April,09)	659,244,545.89	507,646,842.08	308,545,025.19	1,935,789,589.06
Rate of Marketing Margin (US$)	0.135	0.135	0.135	0.135	0.135
Value of Marketing Margin (US$)	62.15	89.00	68.53	41.65	261.33
Cost Recovery (90 *per cent*)	55.93	80.10	61.68	37.49	235.20
PP	6.21	8.90	6.85	4.17	26.13
GoI Share of PP @ 10 *per cent*	0.62	0.89	0.69	0.41	2.61
Royalty @ 5 *per cent* & @ 10 *per cent* for April,09)	3.16 (including 0.0985 million for the month April 2009)	4.45	3.43	2.08	13.12

2.8.3.1.5. The Contractor has collected an amount of US$ 261.33 million towards the Marketing Margin from 2009-10 to 2012-13 which has not been accounted for in the books of JVs. Consequently, Cost Recovery of US$ 235.20 million (90 *per cent*) has not been adjusted in the recovered cost up to 2012-13 and there was a short remittance of GoI share of PP and Royalty by US$ 2.61 million and US$ 13.12 million respectively for the year 2009-10 to 2012-13 to the GoI.

2.8.3.1.6. Audit noted that DGH (April 2011), while submitting Draft MC resolution to MoPNG on the Audited Accounts for the year 2009-10 offered remarks that computation of revenue does not include marketing margin, pending MoPNG decision. DGH (August 2013), in its Draft MC resolution on the Audited Accounts for the year 2011-12 also proposed adjustment for marketing @ 0.135 per mmbtu.

2.8.3.1.7. MoPNG on 26 December 2011 has entrusted the determination of quantum of marketing margin chargeable on sale of natural gas to end consumers by each marketing entity on the basis of its actual marketing cost incurred by it to the Petroleum & Natural Gas Regulatory Board (PNGRB). The issue of marketing margin has not been decided till date. Thus, in spite of the issue of marketing margin being brought to the notice of MoPNG by DGH, no action has been taken by the MoPNG to enforce the decision to include the marketing margin in the revenue of the JV.

2.8.3.1.8. MoPNG in its letter (September 2013) to the Operator stated that *"Section 3.2 (iii) of the Accounting Procedure of the PSC does not allow the Contractor to separately charge marketing costs, either directly or indirectly. However, Operator has charged a marketing margin on sale of gas at the rate of US$ 0.135 per mmbtu over and above US$ 4.205 per mmbtu but the same revenue was refused to be accounted by the Operator in the financial statements. The financial impact of such refusal to account the marketing margin works out to US$ 261 million, which is based on the cumulative gas sales. Accordingly, this amount of US$ 261 million is to be included in the revenues".*

2.8.3.1.9. The Operator in its reply to MoPNG (June 2014) and in the Exit Conference (July 2014) stated that

- *Marketing margin is a charge levied for the costs as well as risk associated with the marketing of gas that occurs beyond the Delivery Point.*
- *As a cost unrelated to the activity of production, the element of marketing margin is supposed to be negotiated and settled between Seller and Buyers while finalizing the terms and conditions of the GSPA.*
- *The response given by the Government of India (MoPNG) in the Parliament to Unstarred Question No.131 and Starred question No.14 on 23.02.2010 in the Rajya Sabha.... unambiguously stated the position as per the PSC, viz. that marketing margin is charged beyond the delivery point and is finalized between buyers and sellers based on the terms of the GSPA.*

2.8.3.1.10. The reply of the Operator is not tenable in view of following:

- Article 27.2 of the PSC states that the *title to Petroleum to which Contractor is entitled under the Contract, and title to Petroleum sold by the Companies shall pass to the relevant buyer party at the Delivery Point. Contractor shall be responsible for all costs and risks prior to the Delivery Point and each buyer party shall be responsible for all costs and risks associated with such buyer party's share after the Delivery Point.*
- Property (title) clause 7 (b) of the GSPA contract states that *"Property (title) in and risk of loss of the Gas delivered hereunder shall pass from Seller to Buyer at Delivery*

Point upon delivery of the Gas to Buyer (or Buyer's designee) at such point". Therefore, at the Delivery Point the title is transferred to Buyers, and beyond the Delivery Point the risk if any, is transferred to Buyers.

- As per Sale Price, clause 6 (b) of GSPA states that the price of gas at Delivery Point shall be the sum of the Gas Price in US$ / mmbtu (NHV) and the Marketing Margin in US$ / mmbtu (NHV). Therefore, at the Delivery Point, the Operator is charging a price higher than the approved Sale Price as finalised by the MoPNG formula.
- As per the MoPNG letter of October 2007 fixing the formula "*if the actual price at which any supplies made to any consumer happens to be higher than the one arrived at by the methodology, then the higher price shall be taken for purposes of the GoI take for that quantity".* Therefore, the Sales Price being charged at a rate higher than the approved rate has to be taken for purposes of the GoI take.
- Audit noted that the MoPNG / DGH (April 2011) has also taken a similar stand that Marketing Margin should be treated as part of revenue.
- In the case of a marketing company like GAIL, GAIL procures gas from ONGC & Oil India Limited and is liable to pay them upfront for the total amount of purchases regardless of the collection it makes from the customers to whom the gas is distributed. However, in the extant case, not only has price been determined but the buyers have also been specified by the MoPNG. Further, the cost of billing, collection and remittance are already being covered, while the transportation costs are separate as they are covered under separate agreement with the Reliance Gas Transportation Infrastructure Limited (RGTIL).

2.8.3.1.11. MoPNG, while accepting that the marketing margin should be included in revenue stated (June 2014) that *"The proposal to include the marketing margin for royalty computation is being examined by MoPNG".*

2.8.3.2 Sale of Condensate

2.8.3.2.1. The production of Condensate from MA oilfield commenced at the OT in Gadimoga on 21 April 2010. The stabilized condensate was being stored in storage tanks in the OT. After examining various options for evacuation / marketing of KG-DWN-98/3 Block Condensate, the Contractor was of the view (July 2010) that the best possible option was to comingle the stabilized Condensate with Ravva Crude at Ravva OT at Surasani Yanam, which is about 60 km from KG-DWN-98/3 OT in Gadimoga.

2.8.3.2.2. While the administrative, procedural and technical issues were still being deliberated, the Contractor informed (8 May 2010) MoPNG that they were currently generating about 200 KL / Day of Condensate and had already a stock of 5200 KL as against a storage capacity of 8000 KL in two tanks at their OT at Gadimoga. With a production rate of 200-250 KL / Day they had to start evacuating the product in the next 5 to 6 days, failing which, they may have to stop production from MA oilfield. The MoPNG, in reply, advised the Contractor on 10 May 2010 to act in accordance with PSC provisions regarding "Domestic Supply, Sale, Disposal and Export of Crude Oil & Condensate" and specifically be guided by provisions of the Article 18.5 of the PSC to dispose off the said petroleum on a current basis and not to cause any restriction to the production.

2.8.3.2.3. The Contractor, on 2 June 2010, informed the MoPNG that though they had formally invited tenders from all oil refining companies for interest and price for KG-DWN-98/3 Condensate, IOCL, CPCL, HPCL and EOL had sent their regrets. Only RIL Jamnagar Refinery responded positively quoting a price of Dated Brent minus 25.6 $/bbl and lifting of 1250 bbls per day as against a production rate of 1500-2000 bbls per day. In order not to cause restriction to production operations of MA oilfield, there was no option but to go ahead with the proposal of RIL Jamnagar Refinery. Since RIL held 90 *per cent* PI in the KG-DWN-98/3 JV, 90 *per cent* of such Condensate quantity would be under stock transfer and balance 10 *per cent* would be sale from NIKO to RIL Jamnagar Refinery as CST sale against Form C. Accordingly, the Operator entered into a Gas Condensate Sale Agreement (GCSA) upto 31 May 2011 with RIL Jamnagar Refinery on 3 July 2010 at a rate of Dated Brent minus 25.6 $/bbl.

2.8.3.2.4. In April 2011, the Contractor invited fresh tenders from all oil refining companies in India for sale of Condensate for the next year (June 2011 – May 2012). Only HPCL and RIL Jamnagar Refinery quoted and IOCL, CPCL, EOL sent their regrets. HPCL quoted a FOB OT price of Dated Brent minus US$ 25.00 /bbl and RIL Jamnagar Refinery this time quoted Dated Brent minus US$ 20.00 / bbl. Contractor stated that since the price proposals from HPCL and RIL Jamnagar Refinery were lower than the Contractor's expectation, both bidders were requested to review their price proposal. RIL Jamnagar Refinery maintained their bid price of Dated Brent minus US$ 20.00 / bbl and HPCL revised their bid to Dated Brent minus US$ 24.95 / bbl. Since the price bid by RIL Jamnagar Refinery's offer was highest the Contractor awarded the contract to them for a term of one year effective 1 June 2011.

2.8.3.2.5. Sale was taking place at a discounted value below Dated Brent, with the level of discount varying. The pricing and sale of Condensate has not yet been approved by the GoI. A meeting was held on 16 August 2011 in the MoPNG to discuss the issue relating to sale of gas condensate from the Block, however, no decision was taken. In spite of the Operator following up several times, the Operator is yet to (July 2014) receive concurrence / consent of the GoI to the pricing formulae for the sale of Condensate. The delay is all the more unacceptable since the FDP for the MA oilfield was approved in April 2008 and production started from April 2009, hence, the process of sale of Condensate by the Contractor and approvals should have been initiated and settled well in advance. In the absence of the final decision of the GoI, the true value of the condensate production cannot be reliably ascertained.

2.8.3.2.6. The difference between the sale price of Dated Brent and KG-DWN-98/3 Condensate amounted to US$ 33.93 million (*Annexure 8*).

2.8.3.2.7. The Operator in its reply to MoPNG (June 2014) stated that *the Audit has arrived at the figure of US$ 33.93 million by simply multiplying the monthly sales quantities with the corresponding monthly average price of Dated Brent which is not a correct assessment as the price can never be Dated Brent.*

2.8.3.2.8. The contention of the Contractor is contradictory because the Contractor himself has entered into GCSA on the basis of Dated Brent. Further, Audit has taken the figures from the audited accounts of the Contractor for arriving at US$ 33.93 million.

2.8.3.2.9. In terms of Article 1.8 of the PSC 'Arms Length Sales' exclude sales involving Affiliates, sales between Companies which are Parties to this Contract, counter trades, restricted or distress sales, sales involving barter arrangements and generally any transactions motivated in whole or in part by considerations other than normal commercial practices. In Audit view, there has to be a clear mechanism to establish that the sale of condensate has been at arm's length as contemplated in PSC.

2.8.3.2.10. DGH stated (17 December 2013) that *"the issue that sale of condensate to Jamnagar Refinery of RIL is not at arm's length had already been flagged by DGH to MoPNG and the same will be addressed by MoPNG while approving the price of Condensate".*

2.8.3.2.11. MoPNG did not give any reasons for the delay in approving the price and sale of the condensate and stated (June 2014) "*As reported by audit, the sale of condensate was not at arms' length. In the event of CAG reporting any variation between the true value of condensate and the price charged, the variation will be suitably factored in by MoPNG for fixing different price*".

2.8.3.2.12. Since the responsibility of ascertaining the true value of condensate lies with the GoI under the PSC, it is reiterated that the price and sale of condensate may be approved by the MoPNG and if any variation is found in the price ascertained by MoPNG, the same may be factored in.

Audit Recommendation 7: 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.

2.9 Accounting issues

2.9.1 Chart of Accounts (CoA)

2.9.1.1. The Accounting Procedure to the PSC sets out principles and procedures of accounting which will enable the GoI to monitor effectively the Contractor's costs, expenditures, production and income so that the GoI's entitlement to PP can be accurately determined pursuant to the terms of the Contract. In particular, the purpose of the Accounting Procedure is to classify costs and expenditures and to define which costs and expenditures shall be allowable for cost recovery and profit sharing and participation purposes. The PSC requires that the Contractor submit and discuss with the GoI a proposed outline of CoA, operating records and reports, which would reflect each of the categories and sub-categories of costs and income as specified in the PSC. This outline is to be approved by the GoI.

2.9.1.2. In January 2001, the Contractor forwarded a common CoA for 12 blocks[67] to DGH stating that the CoA also catered to the needs of final consolidation into RIL's corporate accounts. The Contractor made certain modifications to the existing CoA in March 2002 on the grounds that the changes would facilitate better capture and recording of accounting information and consequently provide for better reporting under both the PSC and JOA of 18 different exploration blocks that they were operating. The Contractor stated that the changed CoA would be used for all the exploration blocks of which RIL was Contractor and would replace the existing CoA forwarded on 19 January 2001. The Contractor further elaborated that the new CoA would be effective from the new budget year starting 1st April 2002. Subsequent to clarifications received from the Contractor, DGH conveyed the approval to this CoA on 24 September 2003.

2.9.1.3. While reviewing the CoA, Audit found that changes had been made to the approved CoA. In response, the Contractor stated (April 2013) that *"during the course of operations, Contractor created new GLs to bring more clarity to the nature of expenses……we strongly feel that the new GLs need not be approved again by DGH as long as these were within the overall framework of outline CoA agreed with DGH…………..Further, Contractor as part of the audited accounts, has been submitting the trial balance which has listing of all General Ledger*".

2.9.1.4. Audit conducted a detailed examination of the changes made to the CoA. Examination of the SAP data for the years 2008-09 to 2011-12 revealed following modifications to the approved CoA:

Table 16 : Additions and deletions to the approved CoA

Year	Number of GLs Added	Number of GLs not used
2008-09	211	167
2009-10	224	184
2010-11	262	140
2011-12	221	196

[67] *GK-OSN-97/1, SR-OSN-97/1, MB-OSN-97/2, MB-OSN-97/3, KK-OSN-97/2, KG-OSN-97/4, KG-OSN-97/3, KG-OSN-97/2, NEC-OSN-97/2, KG-DWN-98/1, KG-DWN-98/3, MN-DWN-98/2.*

2.9.1.5. The Contractor argued (October 2013) that "*Additions / modifications to GLs do not require any specific approval from the Government as long as they are within the overall framework of the outline of CoA agreed with the Government. The additions / modifications to GLs observed by audit are within the overall framework of the outline of CoA agreed with the Government and were required for bringing in more clarity to the nature of expenses. They are concerned with details falling within the overall framework and do not change the outline of the CoA agreed with the Government*".

2.9.1.6. However, in Audit opinion, the CoA is a tool to classify expenditure and any addition / modification to GLs mean change to the classification of expenditure. Since one of the purposes of the Accounting Procedure is proper classification of costs and expenditure, changes to the classification of expenditure, particularly not using those GLs which were part of the approved CoA, requires approval of the GoI. As mentioned earlier, the Contractor himself sought approval of the GoI to the changes made to the CoA in 2002-03.

2.9.1.7. Audit had also requested DGH on 24 May 2012 to provide files / records pertaining to this issue, however, DGH replied on 17 December 2013 that the issue of CoA was dealt with in the initial years of this PSC after award of the contract in April 2000. The files dealing with the issue were not available in DGH. It is clear from the above that DGH has not taken any action on changes being made to the CoA frequently.

2.9.1.8. The Operator in its reply to MoPNG (June 2014) reiterated their stance and also stated that *the chart of accounts is meant to determine the nature of expenditure and this is not a tool for classification of expenditure as envisaged in the PSC.*

2.9.1.9. MoPNG replied (June 2014) that *the details submitted by the Contractor were found adequate for monitoring the expenditure, income, Cost Petroleum, Profit Petroleum and Royalty and requested risk issues to be elaborated.*

2.9.1.10. However, in Audit view, MoPNG may consider approving each GL code added/not used during any financial year. This is exemplified in the case of Parent Company Overhead (refer Para 2.9.2 below) wherein Audit has explained the impact of non-approval of changes in GL codes. In that case the contractor reclassified the Parent Company Overhead under Corporate Office Support to claim an amount of US$ 40 million which was disallowed by MC.

2.9.2 Parent Company Overheads

2.9.2.1. The Accounting Procedure of the PSC stipulates[68] that

- *2.6 – "General and Administrative Costs are expenditures incurred on general administration and management primarily and principally related to Petroleum Operations in or in connection with the Contract Area and shall include*

[68] *Section 2.6 (General Administrative costs) under Section 2 - Classification, Definition and Allocation of costs and expenditures.*

- *2.6.1 – main office, field office and general administrative expenditures in India including supervisory, accounting and employee relations services;*
- *2.6.2 – an annual overhead charge for services rendered by the parent company or an Affiliate to support and manage Petroleum Operations under the Contract, and for staff advice and assistance including financial, legal, accounting and employee relations services, but excluding any remuneration for services charged separately under this Accounting Procedure…".*

2.9.2.2. The Operator has been charging Parent Company Overhead (PCO) since 2002-03 to 2007-08 under Section 2.6.2.

2.9.2.3. The MC disallowed (November 2008) the expenditure on this account up to the FY 2007-08 on the ground that RIL, the Operator, has no Parent Company. MoPNG also conveyed (January 2009) their Audit Exception for the years 2004-05, 2005-06 and 2006-07, based on the Audit Report of the auditors appointed under section 1.9.1 of the Accounting Procedure to PSC, stating that *"for allowing expenditure under the Parent Company Overheads, there should be a distinct parent company or affiliate company. Since company (RIL) is a separate legal entity headquarter or branch office of the same company cannot be treated as distinct parent / affiliate company. Hence no separate charge as overhead can be allowed for cost recovery under this clause (2.6.2) of PSC*".

2.9.2.4. In view of such disallowance by the MC, the Operator, during 2008-09 accounts, reversed the disallowed cost of PCO upto 2007-08 and booked a similar amount under Corporate Office Support (COS) in the year 2008-09 by reclassifying the said disallowed cost as COS cost. The Operator claimed the COS cost under Section 2.6.1. Such reversal was again not agreed to by the DGH at the MC meeting (16 July 2010).

2.9.2.5. The Contractor furnished (July 2010) a certificate from the auditor of the Block certifying that RIL has incurred the expenditure and the same has been allocated out of the allocable expenses to RIL Exploration and Production division. The issue was referred to the MoPNG by the DGH, who conveyed (September 2013) to the Operator that the expenditure is under review of the MoPNG and pending final decision of the GoI, the amount of US$ 40 million was excluded from CP entitlement.

2.9.2.6. Audit found that the Operator, up to 2011-12, has charged US$ 101.41 million as COS.

2.9.2.7. In this regard, Audit opines that though the Contractor has reclassified the expenditure under COS, this does not change the nature of the expenditure. The Operator cannot claim cost recovery for previous year expenditure disallowed by the MC as per provision of PSC, by re-classifying it under a different head and booking it in current year accounts.

2.9.2.8. The Operator in its reply (January 2014) reiterated *that these expenses were* *classified under parent company overheads charges under section 2.6.2. On being disallowed, these expenses were reclassified under section 2.6.1. Confirmation / certificate from RIL statutory auditor, JV auditor and RIL cost auditor certifying the total cost and allocable share to E&P activities has been submitted to MoPNG (December 2013).*

2.9.2.9. Audit, however, noted that expenditures allowable under Article 2.6.1 of the Accounting Procedure to the PSC would include expenditure towards main office, field office and general administrative expenditure in India. Earlier, the Operator, at various stages, has stated that the expenditure was incurred as Parent Company. Now it has changed its views and stated that these were COS.

2.9.2.10. The Operator in its reply to MoPNG (June 2014) stated that

- *Expenditure included under this head was not Parent Company overhead and it was not the intention to charge the Parent Company Overheads.*
- *The Contractor in good faith started claiming the Head Office expenses under annual overhead charge limiting to the allowed percentages under the PSC. It is pertinent to mention here that the MC had approved the annual overhead charges for 6 years starting from 2000-01 until 2005-06. However, while approving the annual accounts for 2006-07, DGH started re-interpreting this unilaterally ignoring the Contractor's submissions and disallowed this expenditure for prior years which was contested by the Contractor.*
- *The Contractor does not agree that the expenditure is disallowed as per the provisions of the PSC. It is further reiterated that the since the expenditure claimed as overheads (at the instance of DGH) for prior years were disallowed, the Contractor had no other alternative but to correctly classify the expenditure under Corporate Office Support and include in the year 2008-09.*
- *Section 2.2.5, 2.3.6 and 2.4 of the Accounting Procedure to the PSC very clearly allows proportionate allocation of General and Administrative Costs to Exploration / Development/Production activities. Further, the Corporate Office Support Costs (Main office expenses) is not included under the lists of costs not recoverable and allowable under the Contract as per Section 3.2 of the Accounting Procedure.*
- *Attention is invited to the minutes of the MC meeting held on 25.1.2002 wherein the Operator explained in detail of the nature of G & A costs incurred by Head Office and the insistence of DGH in claiming the same within the annual overheads charges. It was not the intention of the Operator to claim the head office cost as annual overhead charges, which is applicable only for Parent Company.*

2.9.2.11. MoPNG in its reply (June 2014) stated that *"CAG's audit report No.19 of 2011 was silent on the issue of Parent Company Overheads, though records revealed that the issue had already been raised by DGH and MoPNG. MC disallowed parent company overhead but the issue now in hand is different, that is, allowing allocated common G&A expenditure under the head Corporate Support Services".*

2.9.2.12. It is clarified that the C&AG's Audit Report No 19 of 2011-12 covered transactions during the audit period 2006-07 to 2007-08 in which no audit observation appeared on this issue. However, during the current audit period, in 2008-09, the Operator reversed PCO disallowed up to the year 2007-08 and booked the amount allocated towards PCO by reclassifying the same under COS under Section 2.6.1 of Accounting Procedure of PSC. This event is now being commented upon.

2.9.2.13. It may be noted that, from 2001 onwards, the costs for services rendered by its Head Office were being booked as per Section 2.6.1 of Accounting Procedure. Inclusion under Section 2.6.1 was not found acceptable and so, in January 2002, these expenditures were claimed under Section 2.6.2 of Accounting Procedure under annual overhead charges against the accounting head "Parent Company Charge"[69]. This was, however, disallowed in 2007-08 for the factual reason that the Operator does not have a parent company. Now, again, Operator is claiming these amounts under Section 2.6.1 by reclassifying the expenditure through opening of a new Account head "Corporate Office Support"[70].

2.9.2.14. PCO charges were accounted for without reference to actual expenditure by the Operator upto 2007-08 under Section 2.6.2 of Accounting Procedure. Incidentally, the disallowance has MC approval as accounts upto 2007-08 have been adopted and approved by MC along with the disallowance. Therefore, such disallowed amount cannot be reclaimed by claiming the amount under a different accounting head (from 7840001 (PCO) to 7840020 (COS)) since the nature of expenditure has not changed.

2.9.2.15. The nature of expenditure being claimed since 2008-09 would have to relate to "*main office, field office and general administrative expenditures in India including supervisory, accounting and employee relations services"*. 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. These can be considered for allowance/disallowance only on the basis of independent verification.

2.9.2.16. During the Exit Conference (July 2014), MoPNG stated that the issue was under consideration in DGH/ MoPNG.

2.9.3 Maintenance of Site Restoration Fund

2.9.3.1. Pursuant to Article 14.10 of the PSC, the Contractor is required to prepare a proposal for restoration of site including abandonment plan and requirement of funds for this and any annual contribution in accordance with the scheme framed by GoI for the Site Restoration Fund (SRF). Article 6.6 of the PSC also provides that Operator on behalf of Contractor with the approval of OC shall submit the proposal about abandonment plan/site

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[69] *Accounting head code 7840001.*

[70] *Accounting head code 7840020.*

restoration to the MC for approval. In compliance with these PSC provisions, proposal for maintenance of SRF is required to be submitted along with the Annual WP&B for consideration and approval of the MC so that the site could be restored to the state as of effective date pursuant to the Contractor's environmental impact study and approved by the GoI or to render a site compatible with its intended after-use (to the extent reasonable) after cessation of Petroleum Operations.

2.9.3.2. However, a review of records relating to Annual WP&B for the year 2008-09 to 2011-12 revealed that no proposal for the restoration of site including abandonment plan and requirement of funds for this and any annual contribution in compliance with the above provisions of PSC was submitted to MC for its approval. Consequently, required SRF could not be established / maintained.

2.9.3.3. Audit noted that the Contractor has made an estimate of the site restoration cost for the D1-D3 and MA oilfield for US$ 250 and US$ 32 million respectively during the year 2011-12. The Operator in the notes to accounts (note no. 2(s) to Trial Balance as at 31 March 2012) disclosed that Provisions for decommissioning, abandonment and restoration costs, which are primarily in respect of oil and gas producing wells and production facilities, are made in respective partner's books. However, the Contractor did not create the fund in the books of the JV.

2.9.3.4. Non-provisioning of SRF in Annual WP&B has delayed the formulation of Fund Scheme as well as the annual contribution towards SRF.

2.9.3.5. The Operator in its reply (January 2014) stated that *no time line has been mentioned for creating SRF in the PSC. It is within the best judgment of the Contractor to decide when to create site restoration fund and propose annual contribution to the fund in the annual WP&B for consideration and approval by the MC.*

2.9.3.6. In Audit opinion, as a follower of Good International Petroleum Industry Practices (GIPIP), the Contractor becomes environmentally liable from the start of petroleum operations and, as a prudent measure, the SRF ought to be operationalized so that estimated site restoration cost could be met from it. Moreover, it is obligatory to maintain the fund on the part of Operator so that the site could be restored. MoPNG needs to ensure creation of SRF.

2.9.3.7. The Operator in its reply to MoPNG (June 2014) stated that *"The Contractor reiterates that although Article 14.5(b), 14.5.3, 14.9 to 14.11 of the PSC contains provisions relating to site restoration and envisages creation of SRF, it is silent on the timing of the same. The fact that the PSC provides for Contractor, to propose any annual contribution to SRF clearly suggests that it is within the best judgment of the Contractor to decide when to create SRF and propose contribution in annual WP&B".*

2.9.3.8. MoPNG in its reply (June 2014) stated that *"Depositing money in a site restoration fund would have increased the Contract Cost and reduced the profit petroleum* *available for distribution to Government, but would enable to spread the liability over longer span of time. As the deposit in site restoration fund impacts Cost petroleum".*

2.9.3.9. In Audit view, the Operator is required to create the SRF as per provisions of the PSC. The D1-D3 and MA oilfield is expected to have a life of 11 years till 2020. The Contractor has made an estimate of SRF cost for US$ 250 and US$ 32 million for D1-D3 and MA oilfield respectively, yet the proposal for the abandonment plan/site restoration along with the Annual WP&B has not been submitted to MC for approval. Further, GoI will have to share the burden of SRF at some point of time, which will any way impact cost and profit petroleum. Even from environmental point of view the SRF should be created immediately.

2.9.4 Delay in adoption/approval of annual audited accounts

2.9.4.1. As per provisions of the PSC, the annual audit of accounts should be carried out on behalf of the Contractor by a firm of Chartered Accountants and a copy of the audited accounts should be submitted to GoI within 30 days of receipt thereof. In this regard, Audit, however, observed that though the Contractor had submitted the annual audited accounts of the PSC for the years 2008-09 to 2011-12 to the GoI/MC within 30 days of their receipt by them, the accounts of the Block for all the four years were pending for approval and adoption under Article 6.6 (d) even after a period ranging between more than one year to four years after their submission.

2.9.4.2. On being enquired (June 2012) as to reasons for delay in approval of the audited accounts for 2008-09 to 2010-11, DGH intimated (July 2012) that *audited accounts for 2008-09 and 2009-10 were examined at DGH. During this process, a series of clarifications and queries were sought from the Contractor. On completion of the review process, draft MC resolutions along-with detailed notes were forwarded to the MoPNG nominee on the MC. Further, MoPNG had thereafter sought clarifications/queries on the subject matter for 2008-09. In that sequence, MoPNG had recently sought additional inputs in May 2012, which had been given in July 2012.* Regarding the audited accounts for 2010-11, DGH intimated that *the audited accounts submitted by the Contractor were under examination at DGH. DGH further mentioned that the last clarification had been received from the Contractor in May 2012.*

2.9.4.3. The Operator in its reply to MoPNG (June 2014) stated that *the Contractor welcomes the CAG's comment that the MoPNG should ensure that audited accounts are approved in a timely manner and expedite the approval process.*

Further, in reply to the draft audit report MoPNG stated (June 2014) that *the MC Committee had adopted accounts up to 2007-08. The draft MC resolution for adopting annual accounts up to 2012-13 had been communicated to MOP&NG and were ready for adoption, pending completion of audit by CAG / Government appointed auditors.* It also mentioned that *nevertheless, pending adoption of accounts by MC, in respect of any wrong accounting of expenditure and / or revenue identified, the Contractor had been given instruction to remit additional profit petroleum up to the year 2012-13. The additional profit petroleum* *computation for the year up to 2013-14 was under the consideration of MOP&NG. Further, remittance of Government share of Profit Petroleum was done on quarterly basis without awaiting the approval of audited accounts by the MC. Timely completion of the two levels of audit (out of which the second level was now being done by CAG) would enable timely adoption of accounts by the MC.*

2.9.4.4. In Audit opinion, delays in approval and adoption of audited accounts create uncertainty regarding establishment of definitive CP and PP entitlement of the concerned parties, which ultimately delays in making any necessary adjustment/remedial action. Therefore, as timely approval and adoption of audited accounts is important for timely confirmation of transactions and for taking appropriate corrective measures, the inordinate delays in the approval are against the spirit of PSC. It is further stated that as per the PSC, MC's approval to the Annual Audited Accounts is independent of C&AG audit.

Audit Recommendation 8: MoPNG may ensure that the Audited Accounts are approved in a timely manner in future and expedite the pending approvals.

2.9.5 Change in Accounting Policy – Asset Usage Charges[71] and Notes forming part of the Trial Balance as at 31 March 2009 - No.2 (d)

2.9.5.1. The Operator is allocating asset usage charges (AUC) to all its operating blocks based on the utilization of assets, workstation deployment, log sheets and hours written by employees of E&P Division. These assets are capitalized in the Operator's Company books and the Company is charging depreciation, as per written down value method, on these assets as per the rates prescribed in Schedule XIV to the Companies Act, 1956.

2.9.5.2. Review of the Significant Accounting Polices and Notes forming part of audited trial balance for the year 2008-09 to 2010-11 revealed that the Operator has changed the accounting policy for AUC in respect of software license fees, furniture and fixtures and plant/machinery and equipment from the year 2008-09. As per the changed accounting policy, the Operator had adopted two methods for calculation of the AUC in respect of these assets (i) purchased upto 31 March 2008 and (ii) purchased on or after 1 April 2008. The revision in methodology was made by the Operator taking into account the progress of development work in Block KG-DWN-98/3 and the longer project life. As per the Operator, AUC for assets purchased prior to 31 March 2008 continued to be allocated based on the policy prevailing prior to 31 March 2008 in order to avoid inconsistency with respect to AUC in previous periods.

2.9.5.3. In Audit opinion, the AUC should be calculated uniformly irrespective of the date of purchase of assets and, therefore, the Operator should not recover AUC at different rates on same class of assets purchased at different period of time.

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[71] *Asset Usage Charges represent the amortization of the acquisition cost of an asset not belonging to the Block but used in the Block. These assets have not been procured under the PSC but are in the books of RIL Corporate.*

2.9.5.4. The Operator replied (5 February 2013) that *"The PSC does not prescribe any particular methodology, but allows the operator to charge immediately upon procurement. RIL...applied allocation and charging principles to all of its blocks uniformly on an equitable basis. The Operator has the right, at any time and in its own judgment, to evaluate the most appropriate charging principle. As long as allocation principle is equitable and there is proper disclosure of such modification, there is no violation of the provisions of the PSC. The classification and allocation of costs and expenditure has been conducted strictly in accordance with Section 2 of the Accounting Procedure to the PSC. There is no requirement for Government approval for such change in allocation principles because there has been no deviation from the Accounting Procedure".*

2.9.5.5. DGH stated (16 July 2012) that *the AUC depends on actual cost structure of the respective Contractor and their usage.*

2.9.5.6. MoPNG in its reply (June 2014) stated *"that in the absence of the Contractor not reporting the impact of change in accounting policy, any quantification done by CAG in this respect would be considered for remedial measure".*

2.9.5.7. The Operator in its reply to MoPNG (June 2014) reiterated its earlier response and stated that,

- *"it would be a herculean task to revise the computation for each and every asset retrospectively since inception.*
- *the Operator (on behalf of the Contractor) would find it difficult to debit/credit AUC for the previous years, especially in the case of blocks which are relinquished/surrendered and the JV consortium is dissolved.*
- *the revised computation would definitely give a commercial advantage to the Operator".*

2.9.5.8. Audit feels that the disclosure of the modification is not adequate as Accounting Standard 1 states that *"Any change in the accounting policies which has a material effect in the current period or which is reasonably expected to have a material effect in later periods should be disclosed. Where such amount is not ascertainable, wholly or in part the fact should be indicated".* The effect of change in policy for AUC should be reflected in the accounts similar to the accounting treatment of depreciation as per the Accounting Standard 6 which states that *"The depreciation method selected should be applied consistently from period to period. When such a change in the method of depreciation is made, depreciation should be recalculated in accordance with the new method from the date of the asset coming into use".*

2.9.5.9. The reply of the Operator and MoPNG is to be considered in view of the following:

- As per the terms of the PSC, it is the responsibility of the Operator to prepare all accounting records;
- Audit has given views in accordance with the Accounting Standards and it is the responsibility of the DGH to take a final view to notify the audit exceptions;
- The Operator during 2010-11, in order to ascertain the value of consumption of inventory, has reconstructed the inventory ledger in US$ terms from start and booked US$ 61.76 million as consumption adjustment in KG-DWN-98/3 block.

2.9.5.10. Therefore, due to revision / change in the policy/method of AUC, the AUC should be recalculated as per the new (revised) policy from the date of the purchase of asset. Any deficiency or surplus arising from retrospective re-computation of charges as per the new method is to be adjusted in the accounts in the year in which the method is changed.

2.9.6 Treatment of closing stock of Crude and Condensate

2.9.6.1. As per PSC provisions[72], PP and CP should be calculated on petroleum produced and saved. However, audit scrutiny revealed that the Contractor has not accounted for the value of closing stock of Crude and Condensate valuing to US$ 14.22 million for the years 2008-09 to 2012-13 in the books of JVs. Consequently, cost recovery of US$ 12.80 million towards the value of closing stock has not been adjusted for the years 2008-09 to 2012-13 and there was a short remittance of US$ 0.14 million of PP of closing stock for the years 2008-09 to 2012-13 to the GoI. (*Annexure 9*)

2.9.6.2. DGH in its reply (August 2012) while accepting the point stated that *"the adjustment on account of closing stock of petroleum for all the three years from 2008-09 to 2010-11 have been re-calculated and included while calculating the GoI profit petroleum and yearly and quarterly MC Resolution have been communicated to MoPNG".*

- DGH while submitting Draft MC Resolution (MCR) to MoPNG on the Audited Accounts for the year 2009-10 to 2011-12 also offered remarks that opening stock and closing stock has not been valued in the books of JV. MoPNG in its letter (September 2013) to the Operator communicated that *"the valuation of closing stock as on 31.3.2013 has not been accounted for as part of petroleum produced and saved*".

The Operator in its reply to MoPNG (June 2014) stated that

- *Under Article 27.1 of the PSC, the GoI is the sole owner of all Petroleum produced in the Contract Area until title to such Petroleum passes to the Contractor or any other*

[72] *Article 1.28 - CP means, the portion of the total value of crude oil, condensate and natural gas produced and saved from the contract area which the Contractor is entitled to take in a particular period for the recovery of contract costs provided in Article 15.*

Article 1.77 - profit petroleum means, the total value of crude oil, condensate and natural gas produced and saved from the contract area in a particular period, as reduced by CP and calculated as provided in Article 16.

party in accordance with the PSC. Article 27.2 provides that title to Petroleum passes only at the Delivery point.

- *It would not make any commercial sense for Contractor to make payments of Profit Petroleum to the GoI even before the Contractor has realized any revenue from the sale of such Crude Oil or Gas Condensate. The closing stock available in the storage facility within the FPSO, which is located prior to the Delivery Point, cannot be considered for computation of Profit petroleum as the title to petroleum passes to the Contractor at Delivery Point and not prior to Delivery point.*

- *It may also be noted that the petroleum produced and stored will not be equal to the Petroleum produced and saved. As some quantity may be required to be flared (gas) or burned (OIL) or returned to the reservoir, or can be unavoidably lost e.g. oil that is spilled during the Petroleum Operations.*

2.9.6.3. MoPNG in its reply (June 2014) stated that *"MoPNG's communication to the Contractor to pay additional profit petroleum includes closing stock also"*.

2.9.6.4. The Operator's reply is not tenable in view of following:

- Royalty is being paid on closing stock. Accordingly, closing stock of crude and condensate should have been taken for calculating PP also.
- The Contractor who has adopted accrual system of accounting should consider closing stock also for PP purpose.

2.9.7 Accounting Procedure as per Production Sharing Contracts

2.9.7.1. Section 1.1 of the Accounting Procedure prescribed in the PSCs stipulates the principles and procedures of accounting which will enable the GoI to monitor effectively the Contractor's costs, expenditures, production and income so that the GoI's entitlement to PP can be accurately determined pursuant to the terms of the Contract. More specifically, the purpose of the Accounting Procedure is to

- classify costs and expenditures and to define which costs and expenditures shall be allowable for cost recovery and profit sharing and participation purposes;

- specify the manner in which the Contractor's accounts shall be prepared and approved; and address numerous other accounting related matters.

2.9.7.2. As per Section 1.4.2 of the Accounting Procedure, the Contractor should make various statements relating to the Petroleum Operations *viz.* Production Statement, Value of Production and Pricing Statement, Statement of Costs, Expenditures and Receipts, Cost Recovery Statement, Profit Sharing Statement, Local Procurement Statement, End of Year Statement (based on actual quantities of petroleum produced, income received and costs & expenditure incurred) and Budget Statement.

2.9.7.3. Further, Article 27.4 of the PSC relating to Title to Petroleum, Data and Assets stipulates that assets purchased by the Contractor for use in Petroleum Operations shall be owned by the parties comprising Contractor in proportion to their PI. The GoI shall have the right to require vesting of full title and ownership in it, free of charge and encumbrances of any or all assets, whether fixed or movable acquired and owned by the Contractor for use in Petroleum Operations inside or outside the Contract Area and such right to be exercisable at the GoI's option upon expiry or earlier termination of the Contract. Article 27.5 also stipulates that Contractor shall be responsible for proper maintenance, insurance and safety of all assets acquired for Petroleum Operations and for keeping them in good repair, order and working condition at all times.

2.9.7.4. Audit noted that the Operators have been submitting the audited Trial Balance and notes to the Trial Balance along with Auditor's report and other statements to DGH for approval and adoption by the MC and for audit purpose. However, the accounts prepared by the Operators do not include the Balance Sheet of the JV and other relevant schedules forming part of it.

2.9.7.5. The Operator in its reply to MoPNG (June 2014) stated that *the Joint Venture is an unincorporated entity and the Contractor is not obligated to prepare a full-fledged Balance Sheet. The financial statements have been submitting to DGH annually as part of the audited accounts of the Joint Venture. The contents and formats of these statements are entirely in accordance with the PSC Accounting Procedure and some of the statement additionally included over a period at the request of the Government. In addition to the above, the Contractor has been periodically submitting the Fixed Assets Register.*

2.9.7.6. MoPNG, in reply (June 2014) stated that *the Contractor is an unincorporated joint venture, wherein the transactions required for the purpose of PSC alone is maintained and reported in a format that was framed by DGH, so that the joint venture Contractor is not subject to double taxation at PSC level and then at corporate level. PSC requires maintenance of accounts of expenditure, revenue to ascertain Cost Petroleum and Profit Petroleum and additionally list of assets forming part of Exploration Costs and Development Costs. Accordingly, DGH framed appropriate sets of annual financial statements called as yearend statements, which have been followed consistently by all the Contractors.*

2.9.7.7. A number of high value assets are accounted for in KG-DWN-98/3 block. Audit viewed that preparation of Balance Sheet would help users to know the details of various assets with their respective values and year-wise addition and deletion of assets, and the value of different fixed assets, current assets etc. This will also help the GoI to a) know the position about total assets and b) the position about each type of assets c) various provisions & liabilities and d) to segregate the assets in such a way that they are easily identifiable at the time of expiry of contract.

2.9.7.8. Even though the requirement of preparation of a Balance Sheet for a JV has not been specified in Accounting Standard - 27, we feel that the benefits of preparation of a

Balance Sheet are considerable. Further, keeping in mind the materiality of the cumulative expenditure of more than US $ 10 billion as on 31 March 2012 for the KG-DWN-98/3 block, we are of the considered view that it would present a better state of affairs to the users if a Balance Sheet is prepared by the JV every year. Therefore, MoPNG may consider specifying the requirement of preparing financial statements including Balance Sheet together with notes to accounts for the Blocks under various PSCs.

Audit Recommendation 9: MoPNG may consider issuing audit exceptions under Article 1.9.4 of the Accounting Procedure to the PSC for the audit observations in the section on Accounting as per the specific audit opinion expressed. MoPNG may prescribe financial statements including balance sheet together with notes to accounts for the Blocks.

2.10 Monitoring and reporting issues

2.10.1 Generation of error reports

2.10.1.1. In terms of Section 1.4.2 of the Accounting Procedure to the PSC, the Contractor is required to submit Production Statements showing specified details of Oil, Gas and Condensate produced.

2.10.1.2. According to MC Resolution for 26th MCM held on 10 June 2008 regarding measurement of petroleum in respect of D1-D3 gas field and MA oilfield in KG-DWN-98/3 Block, amongst other decisions, the MC approved the following:

- The point of measurement of volume of petroleum in D1-D3 in r/o Well fluid production shall be a V cone type Wet Gas Flow Meter (WGFM),
- Well fluid at X-mass Tree shall be compared with Production Simulator System / PDMS, and
- Wherever any error in measurement is observed, a format report shall be prepared by the Operator and submitted to GoI.

2.10.1.3. The real time WGFM data is stored in IP21 Server and this data is validated by production engineers to ensure that flows indicated by WGFM remain close to reality. A comparison of the D1-D3 day-wise WGFM data and D1-D3 day-wise gas production data from PDMS revealed differences (*Annexure 10*). The Operator stated (12 November 2013) that the differences were due to the following reasons:

- *On some days, cumulative flow data of some of the flowing wells was not captured resulting in lower total cumulative data,*
- *On some other days, some of the WGFMs were either out of order (Zero flow) or the flow data was not getting cumulated / totaled,*
- *Production volumes were calculated as [Sales + Internal Consumption + Flare] and were not being derived from WGFM data.*

2.10.1.4. DGH also stated (10 March 2014) that *the inspection / testing / verification / calibration of CTMs* (Custody Transfer Meters) *are periodically witnessed by DGH representatives in line with the resolutions approved by the MC. Also that the WGFMs are usually 'fit and forget' types and their frequent replacement / repairs etc. are difficult, hence, adequate redundancies are built up in the form of additional sub-sea meters and other meters in topsides along with relevant hardware and software for production allocation and accounting*.

2.10.1.5. Thus, it is clear from above that DGH was not examining and comparing the WGFMs data with the PDMS data. Further, DGH was not insisting on error reports when there are errors in the WGFMs. Such action is not in accordance with the MC decision dated 10 June 2008, referred to above, which requires generation of error report even in case of a comparison between WGFMs and PDMS data. Further, since the [Sales + Internal Consumption + Flare] is being used as Production from D1-D3 for reporting to DGH, the accuracy of Production Statements could not be verified in Audit.

2.10.1.6. The Contractor in its reply to MoPNG (June 2014) agreed that *the WFGMs had not functioned correctly many times* but neither the Contractor nor MoPNG replied to the specific Audit observation regarding generation of error reports with reference to the above stated MC Resolution.

Audit Recommendation 10: The decisions taken in the MC Resolution for 26th MC Meeting held on 10 June 2008 regarding measurement of petroleum should be followed.

2.10.2 Physical verification of assets

2.10.2.1. As per Section 4.2.1 of the Accounting Procedure of PSC the Contractor should (a) not less than once every twelve (12) Months with respect to movable assets; and (b) not less than once every three (3) Years with respect to immovable assets, take an inventory of the assets used for or in connection with Petroleum Operations in terms of the Contract and address and deliver such inventory to the GoI together with a written statement of the principles upon which valuation of the assets mentioned in such inventory has been based.

2.10.2.2. Accordingly, Physical Verification of Assets (PVA) upto 31 March 2010 was carried out by the Contractor in the presence of DGH representatives from 23 April to 30 April 2011, i.e. in eight days at six different locations. Review of the records relating to PVA provided to Audit, revealed that

- The quantity of assets installed, addition / deletion in the fixed assets was not mentioned in the Assets Register.
- Details of fixed assets retired, i.e. destroyed, scrapped or sold, if any, by the Contractor had also not been mentioned in the assets register.
- DGH had also not prescribed any format for the PV report which could help to verify such adjustments.

- MoPNG requested DGH on 8 June, 23 June, 24 August and 10 October 2011 to furnish the copies of previous years' reports on physical verification of fixed assets. However, the requisite information had not been furnished to MoPNG, so far (November 2012).

2.10.2.3. DGH explained in November 2012 that

- *The role of DGH essentially entails the effective monitoring of Production Sharing Contracts by ensuring the compliance of various provisions specified therein and as per section 4.2.1 of Appendix 'C' of PSC. It is the responsibility of the Contractor to carry out the physical verification of assets and adhere to all the rules, regulations, timelines and procedures pertinent to that, as specified in the PSC provisions.*

- *The PSC provision in respect of the representation of Government nominee should only be seen as a witness to such activity in order to ensure that whether the physical verification exercise as defined in the terms of PSC provisions is being carried out by the contractor or not. It does not require that the Government representative will be a part of the contractor's team to actually carry out such an endeavour. The roles and responsibility in this regard lies completely with the contractor, as per the PSC provisions.*

- *Moreover, the JV auditors have also verified the records available with the Contractor and certified the cost of assets which have been procured, installed, erected and commissioned so far. During the process of physical verification and the assets were visualised and verified by the contractor with the help of camera mounted on ROV.*

- *Subsea assets which were situated at the water depth ranging from (400 m to 1000 m) and scattered over the distance upto 80 Kms, were verified by the contractor with the help of recorded feeds generated through ROV.*

2.10.2.4. MoPNG stated (June 2014) that

- *The Contractor maintains the accounts in the SAP system. The details of quantity of fixed assets procured, installed, retired, scrapped etc should be available in any SAP system. A proper exploration of the SAP system would have enabled the auditors to appreciate the controls that are available in the SAP system.*

- *Article 25 of PSC requires the Operator to maintain the books of accounts on behalf of the Contractor. DGH / MOP&NG do not maintain the records of the Contractors. Audit's comment that records are not available in DGH could not be understood.*

- *Physical verification report would reveal discrepancies if any and secretarial job of formatting such report does not fall on DGH / Government.*

2.10.2.5. The reply of the DGH / MoPNG has to be viewed in the context of the following:

- As per Article 27.4 of the PSC "*the Government shall have the right to require vesting of full title and ownership in it, free of charge and encumbrances of any or all assets, whether fixed or movable acquired and owned by the Contractor for use in Petroleum Operations inside or outside the Contract Area, such right to be exercisable at the Government's option upon expiry or earlier termination of the Contract*". Therefore, DGH who is responsible for monitoring petroleum operation has a right to participate in PV process and is also responsible for keeping up to date information of assets.
- Though it is the responsibility of the Contractor to carry out the physical verification of assets, however, GoI being one of the signatory of the PSC is also a stakeholder in proper verification of assets since the cost of these assets was already recovered or is to be recovered from the revenue earned from the sale of gas/oil.
- A number of high value assets are accounted for in KG-DWN-98/3 block therefore, assurance on the physical verification process followed and status of quantity and location of assets are necessary.
- As regards examination through SAP is concerned, as already stated by Audit in para 2.3.1.7, the access to Assets Accounting module under SAP was not provided to Audit.

2.10.2.6. Thus, MoPNG/ DGH should formulate a system and specify the manner for conducting physical verification of assets.

2.10.3 PSC provisions for regulating deficiencies on part of Contractor / Operator

2.10.3.1. In general, under the PSC, the GoI exercises its rights through the MC. The MC comprises two members from the GoI side and one each from the companies constituting the Contractor[73]. The MC is chaired by a GoI nominee. All matters requiring the approval of the MC are to be generally approved by a unanimous vote of the members of the MC.

2.10.3.2. MC advisory / review functions include Annual WP&B in respect of exploration and appraisal operations and DoC, relinquishment etc. whereas approval functions include Annual WP&B in respect of development / production operations, development plans, audited accounts, appointment of auditor etc.

2.10.3.3. The PSC provides that the Parties shall use their best efforts to settle amicably all disputes, differences or claims arising out of or in connection with any of the terms and conditions of this Contract or concerning the interpretation or performance. In case this is not possible, the Parties can refer the matter to an arbitral tribunal.

[73] *If the Contractor constitutes only one company, it shall have two members on MC.*

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

2.10.3.5. The last option available to the GoI is to terminate the Contract for a number of reasons including, if "the Contractor or a Party comprising the Contractor ('Defaulting Party') has failed to comply with or has contravened the provisions of this Contract in a material particular".

2.10.3.6. This report has pointed out issues where there are differences between the GoI and the Contractor. For instance, issues related to the decline in production have been under discussion since 2011 but neither DGH nor MoPNG have been able to ensure that the Operator undertakes activities as per the approved AIDP. The Operator did not submit a concrete plan to arrest rapid decline in gas production and to increase the gas production rate as per the commitments made under AIDP. Even when DGH had not agreed with the Operator's justification for decline in production it could not do much under the existing PSC provisions for enforcing actions as per the AIDP.

2.10.3.7. In response to Audit, DGH (January 2014) stated that *"while there is certainly a scope to improve the provisions of PSC, it needs to be noted that the Operator has been penalized by disallowing the cumulative costs to the tune of US$ 1005 million up to the FY 2011-12 and US$ 1797 million up to FY 2012-13 for his failure to achieve the approved production rate due to non drilling and connection of production wells"*.

2.10.3.8. Though the MoPNG had issued notice for proportionate disallowance of cost of production facilities amounting to US$ 1.005 billion up to 2011-12, the MoPNG itself admitted before the Standing Committee on Petroleum and Natural Gas (October 2013) that *"It is not penalty as such. Operator said that there is so much of gas and they spent money to recover that gas for the development process but they did not do that. So, we proportionately disallowed the cost of development. So, now only when they produce they will be eligible for that. Default is punishable only by termination of the contract. There is no other remedy*".

2.10.3.9. MoPNG, in November, 2013, issued another notice to the Operator stating that the Operator has, "under-utilised the assets resulting in considerable reduction in production of gas *vis-a-vis* committed gas production rates". Further, MoPNG noted that the Contractor was not contractually entitled to recover development costs incurred on excess production facilities created in D1-D3 fields and, therefore, directed that cumulative cost of US$ 1.797 billion was inadmissible. This amount was to be disallowed from the contract costs of 2012-13. MoPNG also directed "*Operator to remit the additional Profit Petroleum within thirty days*". The Operator did not comply with the directions of MoPNG and instead referred the matter for arbitration.

2.10.3.10. This report has mentioned various instances where the interest of GoI is at stake. These issues includes non-relinquishment of area, DoC, disallowance issues and decline in production. However, there are few interim measures that are available to the GoI. MoPNG/ DGH has been unable to take effective and result oriented punitive measures against the Contractor in such cases. Therefore, Audit is of considered view that the future PSCs need to be strengthened by incorporating sufficient mechanism for overseeing activities and imposing punitive measures, where the occasion so demands.

2.11 Conclusion

The current audit of PSC pertaining to KG-DWN-98/3 Block, conducted to get an assurance that the revenue interests of the GoI were properly protected and that the monitoring and control systems established were effective in ensuring compliance to the PSC provisions, has disclosed weaknesses in the areas of management and contractual obligations.

With regard to transparency and accountability in the manner in which regulatory responsibilities were discharged, audit examination revealed that there was scope for strengthening the PSC regime and implementation thereof so as to ensure that the best interests of GoI as owner of the natural resources were adequately protected. Provisions relating to relinquishment of contract area, declaration and assessment of the viability of discoveries and their commerciality, sharing of risk, approval of development plans are some of the areas in the existing PSC model which may require critical review and rationalisation so that there are no loose ends or vagueness.