47

HYDROCARBON PRODUCTION SHARING CONTRACTS

MINISTRY OF PETROLEUM AND NATURAL GAS

PUBLIC ACCOUNTS COMMITTEE
(2015-16)

FORTY-SEVENTH REPORT

SIXTEENTH LOK SABHA

सत्यमेव जयते

LOK SABHA SECRETARIAT
NEW DELHI

PAC NO. 2079

FORTY-SEVENTH REPORT

PUBLIC ACCOUNTS COMMITTEE
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(SIXTEENTH LOK SABHA)

HYDROCARBON PRODUCTION SHARING CONTRACTS

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Presented to Lok Sabha on: 28.04.2016

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LOK SABHA SECRETARIAT
NEW DELHI

April, 2016 / Vaisakha 1938 (Saka)

CONTENTS

* Will be appended at the time of printing.

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4. Shri Ranjit Singh Brahmpura
5. Shri Nishikant Dubey
6. Shri Gajanan Kirtikar
7. Shri Bhartruhari Mahtab
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10. Shri Dushyant Singh
11. Shri Janardan Singh Sigriwal
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13. Shri Anurag Singh Thakur
14. Shri Shivkumar Udasi
15. Dr. P. Venugopal

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17. Shri Satyavrat Chaturvedi
18. Shri Anil Madhav Dave
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20. Shri Bhubaneswar Kalita
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22. Shri Sukhendu Sekhar Roy

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1. Shri A.K. Singh - Additional Secretary
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Prof. K.V. Thomas - Chairperson

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13. Dr. Kirit Somaiya
14. Shri Anurag Thakur

15[†]. ***Vacant***

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20. Shri Shantaram Naik
21. Shri Sukhendu Sekhar Roy
22. Shri Ramchandra Prasad Singh

[†] Vacant *vice* Dr. M. Thambidurai who has been chosen as Hon'ble Deputy Speaker, Lok Sabha and has since resigned from the membership of the Committee.

COMPOSITION OF THE PUBLIC ACCOUNTS COMMITTEE (2014-15)

Prof. K.V. Thomas - Chairperson

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7. Shri Bhartruhari Mahtab
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10[‡]. ***Vacant***

11. Shri Janardan Singh Sigriwal

12[§]. ***Vacant***

13. Dr. Kirit Somaiya
14. Shri Anurag Thakur

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21. Shri Sukhendu Sekhar Roy
22. Shri Ramchandra Prasad Singh

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‡ Vacant *vice* Shri Rajiv Pratap Rudy who has been appointed as Minister w.e.f. 9th November, 2014.
§ Vacant *vice* Shri Jayant Sinha who has been appointed as Minister w.e.f. 9th November, 2014.
** Vacant *vice* Dr. M. Thambidurai who has been chosen as Hon'ble Deputy Speaker, Lok Sabha and has since resigned from the membership of the Committee.

COMPOSITION OF THE PUBLIC ACCOUNTS COMMITTEE (2014-15)

Prof. K.V. Thomas - Chairperson

MEMBERS

LOK SABHA

2. Shri S.S. Ahluwalia
3. Shri Sudip Bandyopadhyay
4. Shri Ranjit Singh Brahmpura
5. Shri Nishikant Dubey
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7. Shri Bhartruhari Mahtab
8. Shri Ramesh Pokhriyal "Nishank"
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11. Shri Janardan Singh Sigriwal

12[‡‡]. Shri Shiv Kumar Udasi

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14. Shri Anurag Thakur

15[§§]. Dr. P. Venugopal

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20. Shri Shantaram Naik
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22. Shri Ramchandra Prasad Singh

[††] Elected w.e.f. 3rd December, 2014 *vice* Shri Rajiv Pratap Rudy who has been appointed as Minister w.e.f. 9th November, 2014.

[‡‡] Elected w.e.f. 3rd December, 2014 *vice* Shri Jayant Sinha who has been appointed as Minister w.e.f. 9th November, 2014.

[§§] Elected w.e.f. 3rd December, 2014 *vice* Dr. M. Thambidurai who has been chosen as Hon'ble Deputy Speaker, Lok Sabha and has since resigned from the membership of the Committee.

COMPOSITION OF THE PUBLIC ACCOUNTS COMMITTEE (2013-14)

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6. Dr. M. Thambi Durai
7. Shri T.K.S. Elangovan
8. Shri Jayaprakash Hegde
9. Dr. Sanjay Jaiswal
10 Shri Bhartruhari Mahtab
11. Shri Abhijit Mukherjee
12. Shri Sanjay Brijkishorlal Nirupam
13. Shri Ashok Tanwar
***14 Shri Ajay Maken
15. Shri Dharmendra Yadav

RAJYA SABHA

16. Shri Prasanta Chatterjee
17. Shri Prakash Javadekar
†††18 Shri Ashwani Kumar
19. Shri Satish Chandra Misra
‡‡‡20 Dr. V. Maitreyan
21. Shri N.K. Singh
22. Smt. Ambika Soni

*** Elected w.e.f. 14th August, 2013 *vice Dr. Girija Vyas* appointed as Minister of Housing, Urban Development & Poverty Alleviation w.e.f. 17th June, 2013.

††† Elected w.e.f. 3rd September, 2013 *vice* Dr. V. Maitreyan ceased to be a Member upon his retirement as a Member of Rajya Sabha w.e.f. 24th July, 2013.

‡‡‡ Elected w.e.f. 3rd September, 2013 *vice Dr. E.M. Sudarsana Natchiappan* appointed as Minister of State for Commerce and Industry w.e.f. 17th June, 2013.

COMPOSITION OF THE PUBLIC ACCOUNTS COMMITTEE

(2012-13)

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5. Dr. M. Thambidurai
6. Shri T.K.S. Elangovan
7. Shri Anant Kumar Hegde
8. Shri Bhartruhari Mahtab
9. Shri Sanjay Nirupam
10. Shri Shripad Yesso Naik
11. Shri Sarvey Sathyanarayana
12. Shri Ashok Tanwar
13. Dr. Shashi Tharoor
14. Dr. Girija Vyas
15. Shri Dharmendra Yadav

RAJYA SABHA

16. Shri Prasanta Chatterjee
17. Shri Prakash Javadekar
18. Shri Satish Chandra Misra
19. Shri Sukhendu Sekhar Roy
20. Shri J.D. Seelam
21. Shri N.K. Singh
22. Prof. Saif-ud-Din Soz

COMPOSITION OF THE PUBLIC ACCOUNTS COMMITTEE (2012-13)

Dr. Murli Manohar Joshi - Chairman

MEMBERS
LOK SABHA

2. Shri Anandrao Vithoba Adsul
3. Dr. Baliram
4. Shri Sandeep Dikshit
5. Dr. M. Thambidurai
6. Shri T.K.S. Elangovan
7. Shri Anant Kumar Hegde
8. Shri Bhartruhari Mahtab
9. Shri Sanjay Nirupam
10 Shri Shripad Yesso Naik
[§§§]11. Shri Abhijit Mukherjee
12. Shri Ashok Tanwar
[****]13. Shri Takam Sanjoy
14. Dr. Girija Vyas
15. Shri Dharmendra Yadav

RAJYA SABHA

16. Shri Prasanta Chatterjee
17. Shri Prakash Javadekar
18. Shri Satish Chandra Misra
19. Shri Sukhendu Sekhar Roy
20. Shri J.D. Seelam
21. Shri N.K. Singh
22. Prof. Saif-ud-Din Soz

[§§§] Elected w.e.f 6th December, 2012 *vice* Shri Sarvey Sathyanarayana appointed as Minister on 28th October, 2012.
[****] Elected w.e.f 6th December, 2012 *vice* Dr. Shashi Tharoor appointed as Minister on 28th October, 2012.

COMPOSITION OF THE PUBLIC ACCOUNTS COMMITTEE (2012-13)

Dr. Murli Manohar Joshi - Chairman

MEMBERS

LOK SABHA

2. Shri Anandrao Vithoba Adsul
3. Dr. Baliram
4. Shri Sandeep Dikshit
5. Dr. M. Thambidurai
6. Shri T.K.S. Elangovan
7. Shri Anant Kumar Hegde
8. Shri Bhartruhari Mahtab
9. Shri Sanjay Nirupam
10 Shri Shripad Yesso Naik

[††††]11. Shri Abhijit Mukherjee

12. Shri Ashok Tanwar

[‡‡‡‡]13. Shri Takam Sanjoy

14. Dr. Girija Vyas
15. Shri Dharmendra Yadav

RAJYA SABHA

16. Shri Prasanta Chatterjee
17. Shri Prakash Javadekar
18. Shri Satish Chandra Misra
19. Shri Sukhendu Sekhar Roy
20. Shri J.D. Seelam
21. Shri N.K. Singh
22. Prof. Saif-ud-Din Soz

[††††] Vacancy occurred vice Shri Sarvey Sathyanarayana appointed as Minister on 28th October, 2012.

[‡‡‡‡] Vacancy occurred vice Dr. Shashi Tharoor appointed as Minister on 28th October, 2012.

COMPOSITION OF THE PUBLIC ACCOUNTS COMMITTEE
(2011-12)

Dr. Murli Manohar Joshi - Chairman

MEMBERS
LOK SABHA

2. Shri Anandrao Vithoba Adsul

3. **Dr. Baliram**

4. **Shri Sandeep Dikshit**

5. **Shri Anant Kumar Hegde**

6. **Shri Bhartruhari Mahtab**

7. **Shri Shripad Yesso Naik**

8. **Shri Sanjay Nirupam**

9. **Shri Jagdambika Pal**

10 **Dr. Kavuru Sambasiva Rao**

11. **Shri Adhi Sankar**

12. **Kunwar Rewati Raman Singh**

13. **Shri K. Sudhakaran**

14. **Dr. M. Thambidurai**

15. **Dr. Girija Vyas**

RAJYA SABHA

16. **Shri Tariq Anwar**

17. **Shri Prasanta Chatterjee**

18. **Shri Naresh Gujral**

19. **Shri Prakash Javadekar**

20. **Shri Satish Chandra Misra**

[§§§§]**21.** **Shri J.D. Seelam**

22. **Prof. Saif-ud-Din Soz**

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§§§§ Elected w.e.f. 29th August 2011 vide the vacancy occurred vice Smt. Jayanti Natarajan appointed Minister w.e.f. 12th July, 2011.

COMPOSITION OF SUB-COMMITTEE-VIII(HYDROCARBON PRODUCTION SHARING CONTRACTS) OF THE PUBLIC ACCOUNTS COMMITTEE (2015-16)

Shri Sukhendu Sekhar Roy	-	**Convenor**
Shri Shiv Kumar Udasi	-	Alternate Convenor

MEMBERS

LOK SABHA

3. Shri S.S. Ahluwalia
4. Shri Bhartruhari Mahtab
5. Dr. P. Venugopal

RAJYA SABHA

6. Shri Naresh Agrawal
7. Shri Vijay Goel
8. Shri Bhubaneswar Kalita

INTRODUCTION

I, the Chairperson, Public Accounts Committee (2015-16), having been authorised by the Committee, do present this Forty-seventh Report (Sixteenth Lok Sabha) on **'Hydrocarbon Production Sharing Contracts'** based on C&AG Report Nos. 19 of 2011-12 (Performance Audit) and 24 of 2014, Union Government relating to Ministry of Petroleum and Natural Gas.

2. The Report of the Comptroller and Auditor General of India were laid on the Table of the House on 8th September, 2011 and 28th November, 2014 respectively.

3. C&AG Report No.19 of 2011-12 (Performance Audit of Hydrocarbon Production Sharing Contracts) was selected by the Main Committee of PAC for examination in 2011-12 and thereafter the Report continued to be examined during the entire term of the Committee in 15th Lok Sabha. During 16th Lok Sabha, PAC (2014-15) took up C&AG Report No.19 of 2011-12 and on laying of C&AG Report No.24 of 2014 on "Hydrocarbon Production Sharing Contracts" in the Parliament, the same was selected for examination. Subsequently, a Sub-Committee under the convenorship of Shri Sukhendu Shekahar Roy, MP and a Member of PAC was constituted for an in-depth examination of the two reports simultaneously.

4. Public Accounts Committee during 15th Lok Sabha held five sittings wherein briefing/oral evidences of the Ministry of Petroleum &Natural Gas and one of the Operators viz. Reliance Industries Ltd. were taken. During 16th Lok Sabha, PAC (2014-15) called the Ministry for evidence on the Report No. 19 of 2011-12 twice followed by a briefing by C&AG on Report No.24 of 2014.

5. The Sub-Committee-VIII held four sittings to examine the subject. Reliance Industries Ltd. who had requested to be heard on the issues pertaining to them tendered their evidence on 16th February, 2016 and 10th March, 2016 followed by the oral evidence of Oil and Natural Gas Corporation Ltd. (ONGC), Directorate General of Hydrocarbons (DGH) and Ministry of Petroleum and Natural Gas on 21st March, 2016.The Sub-Committee-VIII considered and adopted this Report at their sitting held on 25th April, 2016 and thereafter, the Public Accounts Committee (2015-16) considered and adopted this Report at their sitting held on 26th April, 2016. Minutes of the Sittings form Appendices to the Report.

6. For facility of reference and convenience, the Observations and Recommendations of the Committee have been printed in **bold** and form Part II of the Report.

7. The Committee thank the Predecessor Committees and Sub-Committee for taking oral evidence and obtaining information on the subject as well as finalizing and placing the Draft Report before the main Committee.

8. The Committee would like to express their thanks to the representatives of Ministry of Petroleum and Natural Gas, DGH, ONGC and Reliance Industries Ltd. for tendering evidence before them and furnishing the requisite information to the Committee in connection with the examination of the subject.

9. The Committee place on record their appreciation of the assistance rendered to them in the matter by the Office of the Comptroller and Auditor General of India.

NEW DELHI;	**PROF. K.V.THOMAS**
26th April, 2016	**Chairperson,**
6 Vaisakha 1938 (Saka)	**Public Accounts Committee.**

REPORT
PART – I

I. BACKGROUND

In November, 2007, the Secretary, MoPNG requested the C&AG of India to conduct a special audit of the PSCs for eight blocks *viz.* Ravva, Panna-Mukta, Tapti, KG-DWN-98/3, RJ-ON-90/1, Hazira, KG-OSN-2001/3, and PY-3, for which regular audit had already been carried upto 2003-04/2004-05. The Ministry's request was made in the context of larger stakes of the Government in the form of royalty and profit petroleum, and concerns voiced in some quarters about the capital expenditure being incurred by some contractors in the development projects awarded under the NELP.

2. In March, 2008, the C&AG agreed to the Ministry's request for audit, indicating that Audit would be covering, in the first instance, five blocks – Panna Mukta, Tapti, KG-DWN-98/3, Hazira and PY-3 – out of the eight blocks for which special audit was requested by the Ministry, with the audit of the remaining three blocks to be taken up subsequently in a phased manner.

3. The responses/comments furnished by the Ministry as well as by the operators were duly and appropriately considered and incorporated in the Audit Report 19 of 2011-12 which was finally laid in Parliament on 08.09.2011.

4. The MoPNG, in April 2010, had requested C&AG to undertake audit of 20 fields/blocks for the FYs 2007-08 and 2008-09. The request was accepted by C&AG in February 2012 agreeing to audit 8 blocks and the balance 12 blocks to be audited by Chartered Accountants.

5. Audit of four blocks, viz. PY-1, PY-3, Kharsang and CB-ON-7, was conducted during February to September 2011 for the years 2007-09 at the premises of DGH and the Operator.

6. Audit initiated (May 2012) a Performance Audit of the implementation of Hydrocarbon PSCs at the MoPNG and DGH with respect to Blocks KG-DWN-98/3,

Panna-Mukta, Tapti and RJ-ON-90/1. At the Operators' premises for these blocks, C&AG undertook the financial and propriety audit. While audit at the Operator's premises for RJ-ON-90/1 block commenced in July 2012, audit for KG-DWN-98/3 block and for Panna-Mukta, Tapti blocks commenced in January 2013 only.

7. The observations emanating from the performance audit at the MoPNG and the DGH as well as the results of the financial and propriety audit conducted at the Operators have been presented in report No.24 of 2014.

8. C&AG Report No.19 of 2011-12 (Performance Audit of Hydrocarbon Production Sharing Contracts) was selected by the Main Committee of PAC for examination during 15th Lok Sabha in 2011-12 and thereafter the Report continued to be examined during the entire term of the Committee of 15th Lok Sabha.

9. During 16th Lok Sabha, the Main Committee of PAC in its term (2014-15) continued to examine the same C&AG Report No.19 of 2011-12. Meanwhile on laying of C&AG Report No.24 of 2014 on "Hydrocarbon Production Sharing Contracts" in the Parliament, the same was brought under the subjects selected for examination by the Main Committee of PAC.

Afterwards it was felt that a Sub-Committee on matters related to Hydrocarbons may be formed to have an in-depth examination. Thus, Sub-Committee VIII on Hydrocarbon Production Sharing Contracts has carried out examination of aforesaid two reports simultaneously.

II. INTRODUCTORY

10. Hydrocarbon refers to any of a group of compounds of Hydrogen and Carbon that are found in petrol coal and natural gas. Petroleum covers Hydrocarbons in liquid form *viz.* crude oil as well as in gaseous form *viz.* natural gas. While Hydrocarbon fields primarily contain either crude oil or natural gas, they also include associated natural gas i.e. natural gas produced in association with crude oil as well as condensate *i.e.* liquid Hydrocarbons segregated from natural gas.

11. Petroleum Exploration and Production (E&P) operations are also referred to as upstream operations. Downstream operations include refining of crude oil and marketing of petroleum and gas products while midstream operations (which are often included under downstream operations) include storage, transportation and related activities. The E&P operations *i.e.* the upstream operations can be broadly grouped into three categories

(i) Exploration;

(ii) Development; and

(iii) Production.

12. The first phase in the process for extraction of petroleum is Exploration *i.e.* the search for oil and gas deposits beneath the earth's surface. Such deposits could either be onshore or offshore. Exploration *inter-alia* consists of several sub-phases like Initial Surveys, Seismic Survey, Exploratory well, Appraisal wells and Commercial Discovery.

13. The next phase in the extraction of petroleum is the development of field which first involves the drawing up of a field development plan to ensure the most efficient, beneficial and timely extraction of petroleum keeping in view the engineering, economic, safety and environmental considerations. Development then *inter-alia* includes drilling of production and injection wells, installation of offshore platforms, separators, tankages, pumps etc.

14. The last phase is production which *inter-alia* involves operations and maintenance of the existing fields, workovers, plugging and abandonment of wells, improved oil recovery and site restoration etc.

15. The Exploration & Production (E&P) activities in India started in 1955, when the Government of India decided to develop the oil and natural gas resources in various regions of the country as part of the Public Sector development. With this objective, an Oil and Natural Gas Directorate was set up towards the end of 1955, as a subordinate office under the Ministry of Natural Resources and Scientific Research. In April 1956, the Government of India adopted the Industrial Policy Resolution which placed mineral

oil industry among the schedule 'A' industries, the future development of which was to be the sole and exclusive responsibility of the State. In August 1956, the Oil and Natural Gas Directorate was raised to the status of a 'Commission' with enhanced financial and administrative powers to function efficiently, though it continued to remain under the Government. In October 1959, the 'Commission' was converted into a Statutory Body by an Act of Parliament, which further enhanced the powers of the Commission. In the same year *viz.* 1959, Oil India Ltd. (OIL) was incorporated to carry out the exploration activities in Assam.

16. Thus, the E&P activities in India were carried out predominantly by the two National Oil Companies (NOCs) *viz.* Oil and Natural Gas Corporation (ONGC) and Oil India Ltd. (OIL) by grant of Petroleum Exploration Licenses (PELs) and the Mining Lease (ML) by the Government of India, on nomination basis under the Oil Field Regulation and Development (O&RD) Act, 1948 and the Petroleum and Natural Gas (P&NG) Rules, 1959. The Petroleum Exploration Licenses (PELs) for exploration and exploitation and Mining Lease (ML) for development of Oil and Gas are granted by the Central Government in respect of offshore areas and by the State Governments concerned for onshore areas.

17. Although the exploration efforts made by the ONGC and OIL helped to upgrade the geological reserves, the need for further augmenting the reserves and increasing the drilling density prompted the Government to open the oil and gas blocks to foreign oil companies through several licensing rounds to supplement the efforts of the NOCs. In fact, efforts to involve foreign private companies in the E&P activities of gas and oil in India began as early as 1973, followed by three rounds of bidding between 1980 and 1986 which did not yield any concrete results.

18. The Ministry, therefore, appointed a Committee to consider and identify the blocks which could be offered in the fourth round of bidding. The Committee, so appointed, submitted its Report in August 1989 which almost retained the terms and conditions of the third round of bidding while increasing the scope to also include the private sector domestic companies in the bidding process.

19. In 1991, the Government, as part of the economic reform programme and liberalization process in the oil and gas sector, formulated an exploration policy to invite both foreign and Indian companies with a view to attracting investment and technology. As per this policy, further exploration and exploitation in India, which was already in huge deficit, was to be done by a proper system of Joint Venture. The liberalized economic policy thus sought to deregulate and de-license the core sector, including the Petroleum Sector, with partial disinvestments of Government equity in the PSUs and other related measures. As a consequence thereof ONGC was reorganized as a limited company in February, 1994 under the Company's Act, 1956.

20. In 1993, the Government introduced a policy of round-the-year bidding for the exploratory blocks. In all, a total of nine rounds of bidding were held the details of which are as under:

(i) One round for medium-sized discovered/producing fields;
(ii) Two rounds for small-sized discovered fields; and

(iii) Six rounds for pre-NELP exploratory blocks.

21. Panna-Mukta, Tapti, Raava and Kharsang fall under medium-sized blocks and Hazira, Amguri and Kanwara under small-sized blocks.

22. In view of the need for evolving a strategy to enable the Public Sector and Private Companies to compete for exploration acreages on equal terms and award of blocks to those companies which offer the best in terms of fiscal package and work commitments, the exploration policy was reviewed and a New Exploration Licensing Policy (NELP) was formulated, got the approval of the Cabinet in 1997 and made operational in January, 1999. Under the NELP, suitable fiscal incentives were provided for deepwater areas and also broad contractual and fiscal terms for offering blocks for exploration of oil and gas in the country. One of the important parameters of the NELP was that the NOCs *i.e.* ONGC and OIL were required to compete with the Private players under equal contractual and fiscal framework to acquire exploration acreages. The NELP was aimed at:

(i) Attracting the much needed investment as well as infusion of new technologies in the E&P Sector for bringing more and more unexplored areas under exploration;

(ii) Augmenting the level of exploration activity in the country to find new sources of oil and gas for bridging the gap between demand and supply;

(iii) Providing greater incentives to attract private investments in the E&P Sector;

(iv) Providing a level playing field to all the investors including the NOCs and the domestic and foreign private companies. Grant of exploration licenses through international competitive basis; and

(v) Supplementing the efforts of the NOCs through increased participation by the Private Sector.

23. The fiscal incentives provided to the Contractors under the NELP were as under:

(i) International pricing for crude oil and market driven prices for Natural gas;

(ii) No Oil Industry Development Cess;

(iii) No signature, discovery or production bonuses. Production Sharing Contracts (PSCs) with the Government based on pre-Tax Investment Multiple;

(iv) No custom duty on imports for petroleum operation;

(v) No ring-fencing of expenditure and income for Income Tax purposes;

(vi) Special concessions for deepwater blocks (5 per cent royalty payable on oil and gas for the first seven years);

(vii) Full repatriation of projects;

(viii) Fiscal stability as part of the contract;

(ix) Low to moderate royalty rates ranging between 5 per cent and 12.5 per cent;

(x) Liberal set off of losses and carry forward provisions for Income Tax purposes including 7 year Corporate Tax holiday from the date of commencement of commercial production of mineral oil;

(xi) Tax incentives for Site Restoration Fund Scheme (SRFS); and

(xii) An Empowered Committee of Secretaries consisting of the Secretary, MoPNG, Finance Secretary and Law Secretary would consider the bid evaluation criteria, conduct negotiations with the bidders, wherever necessary and make recommendations to the Cabinet Committee on Economic Affairs (CCEA) on award of blocks.

24. Thus, there was a gradual shift in the E&P policy, from nomination acreage to competitive bidding, first under the pre-NELP regime (both for exploration blocks and discovered fields) and subsequently under the NELP regime to promote investment, efficiency and entrepreneurship. The process of award of contracts under the NELP rounds is broadly as under:

(i) Preparation of data package and basis information docket (Data package contains seismic data, navigation data, relevant maps and well log data for the individual block. Basin information docket is for the basin as a whole and less detailed than the data package);

(ii) Road shows for publicizing the NELP round;

(iii) Publishing of bid document;

(iv) Purchase of bid document and data package/basin information docket by the contractor;

(v) Submission of bids, evaluation thereof, and award of blocks; and

(vi) Signing of Production Sharing Contracts (PSCs).

25. The evaluation of bids is carried out on weightages based on technical and financial capabilities, proposed exploratory work programme and fiscal packages offered. The bidder offering the highest Government Net Present Value (NPV) at 10 per cent discount factor is given the maximum points and other bidders are rated proportionately. The bidder getting the highest points in all the criteria is considered to be the highest bid for award of the blocks.

26. Substantial weightage is given to exploration work as part of the bidding criteria so as to incentivise an aggressive exploration programme with better prospects for discovery of new national oil and gas resources. The exploration programme, which

includes both seismic surveys as well as drilling of exploration wells, is to be carried out in a phased manner within clearly defined timeframes and similarly phased relinquishment of portions of the contract area. At the end of the exploration period, the entire area (except for areas where oil and gas has been discovered or is being developed) is to be returned to the Government which can then re-offer it to other parties through a bidding process, the idea being to prevent hoarding/accumulation of the exploration acreage.

27. The Production Sharing Contract (PSC) was considered as the appropriate regime to attract global players to bring in risk investment as well as technology and entrepreneurship. The Government signed PSCs under three separate regimes as below:

(i) PSCs signed against bidding rounds prior to the approval of NELP in which NOCs are licensees and they are required to pay royalty to the State Government/Central Government in case of commercial discovery and production;

(ii) PSCs signed for the discovered fields in which NOCs have 40 per cent participating interest for medium size fields and no interest for the small size fields; and

(iii) PSCs signed under NELP in which NOCs also participate in the bidding process.

28. The position of PSCs awarded/signed under different fiscal regimes was as under:

Discovered/ Producing fields rounds	–	29
Pre-NELP Exploration Rounds	–	28
NELP Rounds (I to IX)	–	249

29. The three key features under the PSC fiscal regime are Cost Recovery, Profit Petroleum and Investment Multiple.

30. The Cost Recovery Factor (CRF) which is the percentage of revenue that the contractor is entitled to take in a year to recover his exploration development and production cost, is a biddable item. Higher the CRF, the earlier the cost can be recovered, but in such a situation, the contractor's fiscal package will be relatively unattractive as part of the bid evaluation.

31. Profit Petroleum is the available petroleum after the recovery of Cost Petroleum, which is the amount of cost recoverable from the revenues. Profit Petroleum is divided between the Government and the Contractor.

32. The basis on which the share of the Government in Profit Petroleum is decided is called Investment Multiple, to be precise Pre-tax Investment Multiple (PTIM) achieved by the companies in the previous year. PTIM is the ratio of cumulative net cash income to the cumulative exploration and development cost. In arithmetical terms, PTIM is as under:

$$\textbf{PTIM} = \frac{\textbf{Cumulative Net Cash Income}}{\textbf{Cumulative Exploration and Development Cost}}$$

33. In addition to Profit Petroleum, the Government also receives other statutory revenues in the form of Royalty/Dead Rent, Cess, Petroleum Exploration License (PEL) fees and Mining Lease (ML) fees.

34. In order to ensure that the expenditure proposed to be incurred as well as actually incurred by the operator does not adversely affect the Government's revenue interests, the PSC contemplates a Management Committee which has two representatives from the Government of India and one each from the Companies. The Management Committee, Chaired by a GoI representative remains responsible for approving field development plans as well as annual work programmes and budgets for development and production operations. However, operational control of the E&P activities would vest with the Operating Committee, consisting of the representatives of the contractors.

35. Under the PSC, procurement decisions are taken by the contractors who invest their capital. However, the Government has the right to disallow any cost considered for profit computation, if substantiated as irregular procurement. In case of deviations from the procurement procedure, PSC stipulates that the Operator should obtain approval of the Management Committee.

36. In a nutshell, the PSC was considered as the appropriate regime to attract global players for bringing in risk investment as well as technology and entrepreneurship. Though it is called a PSC regime, Royalty regime is also built into a hybrid system wherein the licensee assures a guaranteed royalty on production even before the contractor starts making any profit. PSC facilitates to increase Government share of profit at an increasing scale as compared to the flat rate that exists in the royalty scheme.

37. The representative of the Ministry during oral evidence submitted that

> "At this stage, I would submit before the hon. Committee that the exploration licensing contracts have evolved over a period of time. First we had, as we all know, the nomination regime. Thereafter, the pre-NELP bidding rounds were done. Then, NELP had various rounds. So, this has been evolved over a period of time. But in case of successive contracts, there may be slight variations depending upon the experience in previous contracts. Now, the Government has recently come out, after the experience of various NELP rounds, with a new policy – first, for the small fields and then, for the uniform licensing policy. Whatever problems have been faced in earlier rounds, we have tried to address them.
>
> In the earlier contract, because of the various very tight timelines, this work can be done and this work cannot be done etc. all those issues were there. All those issues were clubbed together and we went to the Cabinet and got some timelines like suppose if it is not done, then what is to be done and how to remove those anomalies or abnormalities which are being created because of these strict timelines or some activity is not to be done and whether that activity should be allowed or not. Based on those experiences, this policy has come. ...we have been learning over the process right from the pre-NELP stage.... Before this, we did not have any deep or an ultra-deep field. First, there was nomination which has no timeline. We brought timelines because somebody should not be squatty over our resources for too long. Earlier there were three phases. Now, there are only two phases. In the present NELP, we have extended it from eight years to ten years. We have also said that exploration can be done

throughout the contract period because ten years period is only for the minimum works programme, but he can carry on its production even throughout.

Earlier, as a result of even the experience of relinquishment, we later on found that it was not paying dividends to the cause of the hydrocarbon exploration. So, from VII NELP onwards, we have done away with 25 per cent – 25 per cent relinquishment. So, it is a fact that it has been a learning process. Sir, 7th, 8th and 9th does not have the concept of relinquishment, which was there of 25 per cent after phase – I and 25 per cent after phase – II.

Similarly, the last issue about which you were talking, we found that there is a lot of rigidity in the timelines and in many cases there was no way forward. What do we do? Suppose, I tell him that you complete this work in three years and if he is not able to do it in three years, then there has to be some mechanism so that further time is given. Now, what we do is that something that is not provided in the production sharing contract, namely, we take it to a Committee called the Empowerment Committee of Secretaries where there is Finance, Secretary; Petroleum, Secretary and Law, Secretary. We take a special dispensation so that we do not get stuck. Basically, the 9-point reforms came to find a way forward because a lot of discoveries were not moving forward.

Yes, Sir. In fact, today also, a lot of people feel that perhaps production-sharing contract is a better regime because it is less risky to the investor. But our experience, over so many years of NELP, has seen that today 90 per cent of problems, which we are facing, and all arbitrations and litigations, are basically related to cost recovery. For example, when you were talking about procurement, now procurement whether he has done a single tender or competitive or non-competitive, if it would have been competitive, then how much less cost would have been there. How do we quantify this? So, there have been a lot of problems that had arisen because of cost recovery. Even though, some people are not too happy with the revenue-sharing model, we, after a lot of deliberations and after talking to a lot of investors, have done it. They say that we are not such much concerned about what model but what is more important is how you implement it. So, considering the ease of doing business, we have gone for it. It is a fact that we have done a lot of improvement over a period of time based on the experience....... Sir, we will think about it, but usually whatever legislation is there has a prospective effect. Even if you see Report 19 and Report 24, C&AG in the first Report said that all those discoveries that have been made after the exploration phase should be disallowed for the cost recovery and Report 24 says that whichever successful wells has resulted into a discovery should be allowed for cost recovery. So, even C&AG over two Reports have realised that perhaps

> there was need for certain relaxation in the larger interest of exploitation of oil and gas........ Sir, the problem would be about prospective as well as retrospective effect.
>
> Sir, the attempt of the Government is always to make the ease of doing business on the part of industries and to be away from micro-management. We give more freedom to the operators to operate and we are concerned with the end-result as to how much production he is doing and with the production related whatever Government’s stake is there, that should come. He should not be able to do any mischief in that and our attempt is to ensure this.
>
> With this view, as I have mentioned, we have already brought in a new policy where we have moved away from the production-sharing to revenue-sharing contract where we will not look at the day-to-day management like cost recovery and other things. We are only interested as to how much production he is doing; how much revenue he is getting; and out of which how much he will share with us. This he has to declare upfront in a formula while bidding and that will be followed. We will not be entering into their day-to-day operations, so we hope that there will be much less scope for arbitration or court cases or disputes. Even within the disputes also, we always prefer the alternative dispute resolution mechanism instead of we going to the court straightaway. But our experience has been that the arbitrations have also gone ahead for quite longer time. So, I think that we will have to see as to how best we can do".

38. The Ministry of Petroleum and Natural Gas (MoPNG) are *inter-alia* responsible for the exploration and production of natural gas, including the administration of the Oilfields (Regulation and Development) Act, 1948. The Ministry are assisted by the Directorate General of Hydrocarbons (DGH), which was established in April, 1993 with the objective of promoting sound management of Indian petroleum and natural gas resources having a balanced regard for the environment, safety, technological and economic aspects of petroleum activities.

39. According to the Audit, 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, 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.

40. MoPNG in its reply state that Monitoring of the PSC has been done in letter & spirit. In order to facilitate the E & P operations to achieve energy security of the nation, holistic approach has been adopted. Adequate precautions and steps have been taken to ensure that controls are in place and E&P operations are carried out as intended. In general, Ministry has taken steps for streamlining the Management Committee functioning such as procedure for scheduling the meetings, timely disposal of resolutions etc.

41. Audit recommended that the functions currently discharged by the DGH should be clearly demarcated.

- The technical advisory and related functions should be discharged by a body under MOPNG

- Regulatory functions (review of hydrocarbon reserves and reservoir management, laying down of norms for declaration of discoveries, laying down safety and related norms and conducting safety inspections / audits etc.) should be discharged by an autonomous body

42. MoPNG replied that:

"Regulatory functions is demarcated & laid down by way of contract terms, Act and Rules. DGH role is ensuring compliance of regulations by Contractors.
Roles of technical advisory is discharged by DGH under the direct control of MOP&NG.
A separate study by BCG was done by MOP&NG, before taking further course of action

Under the PSC, there are different timelines specified for carrying out exploration, development and production operations that are required to be followed by the contractor. There are more than 250 PSCs in operation in the country that are being monitored by the MoPNG/DGH. There are two representative of the GoI one from the MoPNG and the other from the DGH in the Management Committee (MC). When asked whether the said representative were not fully equipped to protect GoI interest at every stage of E&P, be it exploration, development or production, which have not been justified thereby affecting the GoI's share of profit and the steps have been taken by the Ministry to strengthen the monitoring of the PSC at the level of MoPNG and DGH

Reply:

Directorate General of Hydrocarbons (DGH) is the technical arm of MOP&NG having expertise in technical matters such as Geology, Geophysics, Logging, Drilling, Production, Environment, Pipeline, Legal and Finance matters. Most of the officers in DGH with above background are having more than 20 - 25 years of experience in respective fields. They are also given exposure by deputing them in various related trainings and National/ International conference. DGH has its own state of the art work centre including Virtual Reality Centre, different software with facilities to evaluate all kind of Geological and reservoir parameter of proposals.

Most of the non compliance of PSC provisions related to notification of potential commercial interest, appraisal programmes and submission of Field Development Plans etc. has occurred as there is no provision in PSC for extension/ relaxation of these timelines. At the same time, if discoveries are not agreed based on non adherence to the PSC provisions, the explored reserves can not be monetised.

In view of above, Government has recently approved policy framework, for relaxations, extensions and clarifications at the development and production stage under the PSC regime for early monetisation of hydrocarbon discoveries where MC / DGH have been authorized to condone the delays and extension of timelines to certain extent after paying pre defined fee. This will help in regularizing such unintended delays in notification of potential commercial interest, appraisal programmes and submission of Field Development Plans etc. in accordance with the PSC.

During the exploration phase of the blocks, the associated work are mainly related to exploration activities and thus Government has kept the provision for keeping both the MC members from DGH, one being the Chairman and the other the Deputy Chairman of the MC. Once any discovery is made in the block, one MC member from Exploration division of Ministry is appointed in the MC. As soon as the production starts from the block/ field, one member from IFD division of Ministry is kept in MC. Generally the Chairman is from the Ministry and the Deputy Chairman in the MC is from the DGH.

All the proposals submitted to Management Committee are examined in depth for its technical, commercial evaluation and legal implications in DGH before considering it for MC review/ approval. DGH also hires outside international experts/ consultancy firms as and when required. The issues are then taken up in MC after evaluation of proposals to take care of Government interest.
All the matter requiring the approval of the MC shall be approved by a unanimous vote of the members of the MC. However if unanimity is not achieved the decision of the MC may be approved by the majority participating interest of 70% or more with the Government having a positive vote in favor of the decision. Hence any business which requires MC approval can be approved only when it has the approval of the Government i.e. the Government having a veto power for approving a resolution. In this way the claim of the Ministry is substantiated".

43. The views of Ashok Chawla Committee (Committee on allocation of natural resources) are as under:

- In petroleum, the allocation process under NELP is seen as a benchmark for transparency in the natural resources sector. It is undeniable that the NELP model is distinctly ahead of the methods of allocation seen in other sectors.

- Creation of a National Data Repository has been an issue which affects the degree of interest in exploration.

- The bid parameter of pre-tax investment multiple does provide possibilities for gaming during the pendency of the contract.
- Concerns are enhanced that there is significant circulation of personnel between state-owned operators and oversight bodies which enhances the perception of conflict of interest.

- Transparency in the management of contracts and associated considerable financial implications should be enhanced by increasing the independence of the regulatory mechanism, clarifying the separation of the policy maker, regulator and the operator and bringing the decision making process into the open.

- A complete unshackling of the natural gas market, without restrictions on utilization and pricing, development of gas pipelines and re-gasification terminals and transparent regulatory oversight appears to be most optimal framework for allocation of gas.

MoPNG in its reply on implementation of the recommendations of Chawla Committee stated that "The Government has decided to adopt a revenue sharing model contract for future rounds of bidding in place of the present profit sharing model. A National Data Repository is in the final stage of completion in DGH to promote data viewing by global E&P companies. The Government has already initiated steps to provide marketing and pricing freedom to natural gas in a calibrated manner. Some of the important decisions in this regard are introduction of marketing and pricing freedom for the gas to be produced from the difficult areas such as deep water, ultra deep water, high pressure and high temperature reservoirs with a upper cap on pricing, introduction of pricing and marketing freedoms for the fields to be auctioned under the Discovered Small Fields Policy and blocks to be offered under new Hydrocarbon Exploration and Licensing Policy".

44. Article 25 of PSC stipulates 2 levels of audit by independent auditors.

1. Appointed by the Management Committee
2. Appointed by the Government

- CAG did the 2nd level PSC audit in Contractor's premises for blocks selected by CAG since 2006-07

3. Report no 19: on 20 PSCs for years 2006-07 to 2007-08
4. Report no 24: on 4 PSCs for years 2008-09 to 2011-12

45. Against the above backdrop, the Public Accounts Committee took up the subject for examination and report. In the process, the Committee obtained Advance Information, Written Reply and Post Evidence Information from the Ministry of Petroleum & Natural Gas. The Committee also took oral evidences of the Ministry and the operators *i.e.* Reliance Industries Limited (RIL) and their Joint Venture partners and ONGC besides obtaining written clarifications from the Operator. The Committee had an interactive session on the subject with the then C&AG and his team of officers. Based on all the aforesaid written and oral depositions, the Committee have discussed the prominent issues in the succeeding paragraphs.

A. Investment Multiple (IM)/ Pre-Tax Investment Multiple (PTIM)

46. As stated earlier, the basis on which the share of the Government in Profit Petroleum is decided is called Investment Multiple (IM), to be precise Pre-Tax Investment Multiple (PTIM), achieved by of cumulative net cash income to the

cumulative exploration and development cost. The Ashok Chawla Committee on 'Allocation of Natural Resources' has observed that the IM-based profit sharing system *"gives incentive (to an operator) to increase his investment, or front-end his work plan in order to see that the threshold where Governments' profit take rises rapidly is not reached."* Citing the example of KG-DWN-98/3, the Committee has stated that *"the relationship between the pre-tax IM and the share of contractor profit petroleum changes dramatically once the pre-tax IM crosses 2.5, with the Government's share increasing from 28 per cent to 85 per cent. It is useful to remember that this schedule is bid by the operator, and not determined by the Government."* The Ashok Chawla Committee has further observed that *"a high share of some pre-tax IM will help to win the bid, depending on the financial mode of evaluation used, but it does raise concerns that such a radical change would provide very strong incentives for any operator to adopt all investment and strategies possible to ensure that the pre-tax IM stays within the 2.5 limit."*

47. When asked about the views of the Ministry on the suggestion of the Audit regarding removal of IM linkage with the profit sharing formula and would it reduce the incentive for skewed volume and timing of capital expenditure resulting in very low GOI share of Petroleum Profit or Does the Ministry have any other formula under consideration, the Ministry replied as under:

> "In the PSC the Contractor's profitability is measured by computing IM or the return on his investment (ROI). The calculations of profit petroleum based on the IM based formula has been contested by many experts including the Ashok Chawla Committee, Dr Rangarajan Committee and C&AG".

48. MoPNG further stated that "After examination of the recommendations of the Ashok Chawla Committee, C&AG report and Dr C Rangarajan Committee report and further consulations with the stakeholders, the Government has decided to adopt revenue sharing model for future bidding round, where the Government take will be a percentage of the total revenue linked to the daily production rate and petroleum prices. Thus the new revenue model will do away with the necessity of considering cost and

investment multiple and will be in tune with governments policy of minimum government maximum governance.

49. When asked about the observation of the Audit on gas pricing, MoPNG stated that "Govt. is of the opinion that Indian gas market can be developed with full potential only if competitive equivalent gas pricing mechanism is in place. In line with the same objective, Govt. announced “The New Domestic Natural Gas Pricing Guidelines, 2014” wherein price of domestically produced natural gas is linked to prices of four important international hubs.

50. The Government has already initiated steps to provide marketing and pricing freedom to natural gas in a calibrated manner. Some of the important decisions in this regard are introduction of marketing and pricing freedom for the gas to be produced from the difficult areas such as deep water, ultra deep water, high pressure and high temperature reservoirs with a upper cap on pricing, introduction of pricing and marketing freedoms for the fields to be auctioned under the Discovered Small Fields Policy and blocks to be offered under new Hydrocarbon Exploration and Licensing Policy.

51. When asked how does the Ministry / DGH determine the authenticity of the development and exploration cost projected by the contractor to ensure that the actual expenditure vis-à-vis the committed expenditure does not increase manifold, the Ministry stated as under:

> "Under the Production Sharing Contracts, the Contractor commits to undertake exploration operations such as 2D and 3D seismic survey, drilling of exploratory wells etc. during the exploration phases. This commitment is in the form of completion of physical activities and not in the form of monetary targets. All the activities duly approved by operating committee are presented to management committee for review/approval in the form of annual work program and budget. Review/approval of annual work program and budget is first level of control where the exploration activities to be carried out in a year are reviewed/approved vis-a-vis minimum work program and development activities are approved vis-a-vis the approved Field Development Plan (FDP).
>
> The operator then carries out necessary procurement of goods and services at arm’s length in line with the provisions laid down in the procurement procedure of Acquisition of Goods and Services of the PSC.

In case of affiliated transactions, the profit element is to be excluded from cost as per the PSC provisions. These laid down procedures in the PSC acts as a second level of control.

MC appointed auditor then carries out audit as per pre-defined broad guidelines provided by C&AG and any discrepancies are notified in the audit report. Moreover, the audit conducted by the MC appointed audited acts as the third level of control.

Finally, the Govt. auditor appointed by DGH/MoP&NG audits the accounts of the contractor and submits final audit report based on which Govt. notifies audit exceptions to the contractor and disallows any cost which are not allowable as per the provisions of the PSC. It is pertinent to mention that there is no bid commitment on the Contractor for development operations which actually depends on the success of the exploration operations.

For the purpose of computation of Profit Petroleum that is shared between the Government and the Contractor, the actual expenditure incurred by the Contractor as per the books of accounts duly audited by the two levels of auditors becomes the basis of computation. In some of the large blocks, the audit is done by CAG also. No notional cost or cost estimate of the Contractor is accounted for the purpose of Profit Petroleum".

52. On being asked what steps have been taken by the Ministry/DGH to ascertain that the cost being incurred by the contractor is reasonable and correct, the Ministry replied as under:

"No notional cost or cost estimate is allowed to be accounted for the purpose of Profit Petroleum. Only the actual expenditure duly supported by documents evidencing the incurrence of such expenditures is allowed to be accounted in accordance with the Accounting Standards.

Section 3.1.8 of the Accounting Procedure of the PSC states that so far as is practicable and consistent with efficient and economical operation, only such material shall be purchased or furnished by the contractor for use in the petroleum operations as may be required for use in the reasonably foreseeable future and the accumulation of surplus stocks shall be avoided. Material and equipment held in inventory shall only be charged to the accounts when such material is removed from inventory and used in petroleum operations cost shall be charged to the accounting records and books based on the “First – in – First – Out method”.

Further every model PSC has a separate Appendix on procurement of goods & services clearly mentioning therein the Objectives, Principles & Procedure for acquisition of Goods & Services. The PSC provides a mechanism for acquiring goods at arm’s length and then audit by the Government.

As stated earlier, management committee reviews the annual work program and budget in consonance with approved field development plan or minimum work program (MWP). The contractor follows the procurement procedures laid down in the PSC for acquisition of goods and services which are required for the work to be conducted for exploration and development operations reviewed/approved by the management committee.

The expenditures are audited by independent auditors appointed by the Management Committee followed by audit by auditors appointed by the Government. DGH has laid down extensively the scope of verification to be done by the auditors during the audit of the accounts. In order to ensure the correctness and reasonability of cost, only the expenditure actually incurred by the Contractor based on audited financial statements is considered as Contract Cost.

Any affiliated transaction of the Contractors is checked and profit element in the affiliated transactions is disallowed as per the provisions of the PSC".

53. When asked what corrective and remedial measures have the Ministry taken to ensure that the cost being depicted in the PSC accounts by the contractor especially for the procurement of goods and services that critically affect the determination of profit petroleum and the Government share therein are correctly and competitively determined, the Ministry submitted as under:

"Procurement process stipulated in PSC is considered to be adequate to ensure that procurement is done at arm’s length at reasonable and prevailing market rates. Cost that are not allowed as per the PSC provisions are specifically mentioned in Section 3.2 of Accounting Procedure of PSC for disallowance.

Government draws comfort on reasonableness of cost based on the business model that Contractor does not stand benefitted by paying a higher price in an arm’s length procurement. A higher procurement cost will hurt Contractor’s profitability more, unless it is an affiliated transaction. Management committee also reviews the activities planned during any year based on work program and approved field development plan. The procurement of goods and services are done based on the approved work program and budget following the accounting and procurement procedures. Nevertheless, in the opinion of Audit, any specific cost accounted as Contract Cost in the financial statements of JV is to be disallowed on the ground of unreasonableness, appropriate remedial action are considered.

Cost used for computation of Profit Petroleum and Government share of Profit Petroleum is ensured to be based on audited actual expenditure incurred by the Contractor. The expenditures are allowed to be recognized in the books of accounts in accordance with the Accounting Standards of ICAI.

The books of accounts are audited in accordance with the Audit Standards. There are two level of audit prescribed under each PSC. In case of the block KG-DWN-98/3 the 2nd audit was carried out by CAG. Any incorrect reporting of costs is disallowed for the purpose of profit petroleum computation.

Procurements from affiliated parties that may adversely impact the cost are verified during the audit. Profit element, if any, in any affiliated transactions is excluded from Contract Cost as per the provisions of PSC".

Findings relating to KG-DWN-98/3 (Operator - RIL) as per 19 of 2011-12

(i) The Contractor was allowed to enter the second and third phases of exploration without relinquishing 25 per cent each of the total contract area at the end of Phase-I and Phase-II as against Articles 4.1 & 4.2 of the PSC. Subsequently in February, 2009, the Government of India also conveyed approval to treat the entire contract area of 7645 sq. k.m. as 'Discovery Area', thus enabling the operator to completely avoid relinquishment of area.

(ii) The operator's views at different points of time clearly attempted to confuse potential/prospectivity with actual discovery of hydrocarbons. The operator's difficulties in hiring ultra-deepwater rigs for the deep water area of the block (essentially the SW part, where no discoveries had been made) had no linkage with the contractual provisions for discovery area and relinquishment.

(iii) In violation of the PSC provisions, in the case of 13 out of 19 Discoveries between October 2002 and July 2008, the operator had without first furnishing the initial particulars of the discoveries in writing to the Management Committee and the Government, directly given written notifications regarding potential commerciality of the Discoveries.

(iv) Most procurement activities were undertaken late in line with the schedules of the Initial Development Plan of May 2004. By contrast, activities in respect of items in the Addendum to the IDP (AIDP) were initiated even before the submission/approval of the AIDP. Clearly, the development activities of the operator were guided by AIDP, rather than IDP.

(v) Payments made during 2006-07 and 2007-08 revealed instances of huge procurement contracts where Audit could not derive assurance as to the reasonableness of the costs incurred, primarily due to lack of adequate competition-award on single financial bids; major revisions in scope/quantities/specifications; post-price bid opening; substantial variation orders-with consequential adverse implications for cost recovery and the GoI's financial take.

(vi) Particularly in case of MA oilfield, Audit found that well before submission, let alone approval, of the Field Development Plan (FDP) and Mining Lease (ML) application, the operator had placed orders for various critical items required for development activities/production facilities from 2006 itself.

(vii) Several instances were noticed where multiple vendors were pre-qualified, but when technical bids were received, all vendors (except one) were rejected and the contract was finally awarded on a single financial bid.

Findings relating to KG-DWN-98/3 (Operator - RIL) as per 24 of 2014

Regulatory and control issues

- In none of the four years' audit period was the annual Work Programme and Budget (WP&B) approved before start of the FY. The WP&B is one of the most important tools available with the MC to exercise monitoring and control over the operations of the block. Since MC did not effectively utilize this tool, there was inadequate budgetary / financial control over operational activities leaving the expenditure open-ended.
- Expenditure amounting to US$ 160.81 million incurred on account of three appraisal wells was not eligible for cost recovery and had been disallowed by MoPNG. However, even after the MoPNG communicated its decision, the Operator continued to claim the cost recovery, as seen in the final accounts for the year ended 2013. As of June 2014, the MoPNGhadbeen unable to enforce its decision.

Approvals for petroleum operations

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

improperly carried out at the risk of revenue of the commercial discoveries made in the block.

- As per PSC provisions, the review of DoCin respect of three discoveries, *viz.* D 29, D 30 and D 31, was to be completed by MC by August 2010. However, due to lack of adequate production testing data, DGH rejected the DoC proposal. Nonetheless, despite technical advice of the DGH to the contrary, the issue has been reopened after almost three years from the date when it was rejected by DGH and has not been finalised as yet.
- 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.
- The Operator was required to drill, connect and put on stream 22 wells under Phase I of approved AIDP. However, the Operator drilled, completed and connected only 18 wells. Gas production started declining in August 2010. While production level achieved in 2010-11 was 90 *per cent* of approved production profile, this figure decreased to 57 *per cent* in 2011-12 and 26 *per cent* in 2012-13.The Operator failed to adhere to the approved AIDP in terms of numbers of producer wells to be drilled and connected.
- The Operator created facilities to handle gas production of 80 mmscmd. As of March 2012, the Operator had incurred expenditure of US$ 5.76 billion on the development of D1-D3 gas fields as against the MC approved cost of US$ 5.20 billion. The facilities created by the Operator remained underutilized / unutilized due to declining trend in gas production and non-drilling of wells as per the approved AIDP.
- DGH approved Optimized Field Development Plan (OFDP) for four satellite discoveries. Initially, the OFDP was not techno-economically viable; however, it was made marginally viable by devising different scenario and changing assumptions, e.g. exclusion of royalty as expenditure, variation in capex etc.

Expenditure related issues

- Engineering, Procurement, Installation and Construction (EPIC) contract of offshore facilities was awarded to M/s Allseas Marine Contractors (AMC) at a lump sum and provisional price of Euro 699.09 million and Euro 64.99 million respectively. Due to various factors attributable to Operator, AMC and its sub-contractors, AMC could not achieve the milestones. Concessions of Euro 200 million approximatelygivento AMC by the Operator in order to expedite completion of the works were not allowable for cost recovery as the concessions were not in line with EPIC contract including provisions relating to ‘change in contract price’; and were in violation of Section 3.2 (ix) of Appendix C to the Accounting

Procedure to PSC which states that, "*amounts paid with respect to non-fulfilment of contractual obligations are not recoverable and not allowable*". (Para 2.7.1.1)

- Within four months from the date of signing the agreement, the Operator requested the FPSO vendor to extend the dry docking life of the FPSO from ten to fifteen years for a one-time compensation of US$ 17.36 million.Since the FPSO was charteredfor 10 years only, extension of dry docking to fifteen years is not justified and the cost recovery of US$ 17.36 million may be disallowed.

- Despite the FPSO vendor being unable to meet its contractual obligations, the Operator re-scheduled the date of first production of oil (DFPO), without imposing any penalty. In addition, though there was no provision in the agreement which entitled the vendor to any compensation or incentive for expediting deliveries, the Operator paid compensation of US$ 45 million to the vendor for early mobilization of the vendor's commissioning team and expediting deliveries of top side modules etc., which may be disallowed.

- The FPSO has been leased for ten years. However, the Operator refurbished the existing living quarters and fabricated and installed additional living quarters, at a cost of US$ 15 million with the intention to purchase the FPSO at a later date. Audit recommends that the cost recovery of US$ 15 million may be disallowed.
(Para 2.7.1.2.1, 2.7.1.2.2 and 2.7.1.2.3)

- As per the Onshore Terminal (OT) construction contract, no compensation was payable to the vendor on account of Plant and Equipment (P&E) provided by RIL in case the vendor was unable to mobilize the P&E. However, an amount of INR 22.7 million was paid to the vendor as compensation charges for Cranes which were hired by RIL by amending the contract to exclude these cranes.
(Para 2.7.2.1)

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

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

- Despite having adequate drilling prospects and keeping in view the poor response received from the vendors for provisioning of the rigs indicative of the scarcity of deep-water drilling rigs, the Operator did not consider it prudent to consider the option of long-term hiring of the drilling rigs and availing the firm rate advantage of such long-term hiring. This resulted in additional expenditure of approximately US$ 88.77 million in piece-meal hiring of deepwater drill ship "Deepwater Frontier" from M/s Transocean Offshore International Ventures Limited.
- Operator paid bonus for time saved during the rig movement between wells with hanging Blow Out Preventor (BOP). As per the contract clause, any bonus payment was to take into account the sum total of time saved for all the operational activities for completion of a well rather than a single activity. Therefore, payment of bonus for rig movement with hanging BOP was not justified and resulted in additional expenditure of US$ 2.83 million.
- The Operator paid uptime bonus of US$ 13.37 million to M/s. Aker Contracting FP AS, Norway (ACFP), which resulted in additional benefit to the vendor, as normally bonus payments are extra payments given as a reward or incentive for earlier completion of work or increase in production level, not for performing their contractual obligations. In this case, ACFP was contractually bound to make available FPSO during the charter period.

Revenue issues

- The pricing mechanism for Crude from MA oilfield has not been finalized and approved by MoPNG. The sales (under COSA) are being treated as provisional by the MoPNG. However, the Operator is treating the sales as firm and final. Marker has not been fixed so far leaving scope for ambiguity in pricing.
- The pricing and sale of Condensate has not yet been approved by the Government. It is being sold at a discount value below Dated Brent. The difference between the sale value of Dated Brent and KG-DWN-98/3 Condensate amounted to US$ 33.93 million during the period July 2010 to March 2012.
- Operator is charging the gas price at the rate of US$ 4.340 mmbtu which includes 0.135 US$/mmbtu towards marketing margin from its consumers. Marketing margin is not being considered as revenue for the purpose of Cost Petroleum, Profit Petroleum and Royalty while Contractor has collected an amount of US$261.33 million on this account for the period 2009-10 to 2012-13.

Accounting issues

- Parent Company Overhead (PCO) charged by the Operator for cost recovery up to the financial year 2007-08 under Section 2.6.2 of Accounting Procedure of PSC was disallowed by MC while adopting the

Accounts for the year 2008-09, on the ground that Operator (RIL) has no parent company. However, Contractor has reclassified and claimed these expenditures amounting to US$ 101.41 million (upto 2011-12) under Corporate Office Support (COS). Such expenditure cannot be vouched by Audit in the absence of documentary evidence and by placing reliance only on the basis of a certificate of a Company Auditor appointed by RIL or a certificate given by the JV Auditor appointed by MC who in turn had relied upon the certificate given by the Company Auditor.

- Closing stock of crude and condensate had not been accounted for in the books of the JV. Consequently, cost recovery of US$ 12.80 million towards the value of closing stock had not been adjusted for the years 2008-09 to 2012-13 and there was a short remittance of US$ 0.14 million of Profit Petroleum of closing stock for the years 2008-09 to2012-13".

B. <u>Non-relinquishment of the contract area</u>

54. Audit scrutiny revealed that in the case of KG-DWN-98/3 the contractor was allowed to enter the second and third phases of exploration without relinquishing 25 per cent each of the total contract area at the end of Phase-I and Phase-II as against Articles 4.1 & 4.2 of the PSC. Subsequently, in February, 2009 the GoI also conveyed approval to treat the entire contract area of 7645 sq. km. as 'Discovery Area', thus enabling the contractor to completely avoid relinquishment of area.

55. Audit further pointed out that though DGH initially objected to the contractor's view that it was not in a position to identify any area for relinquishment and advised RIL to relinquish 25 per cent area, it allowed the contractor to proceed from Exploration Phase-I to Phase-II without such relinquishment (while continuing to debate and discuss the question of relinquishment). By April/May 2005, DGH undertook an about-turn, indicating that 'It would be prudent to acquire and interpret the 3D seismic data in the remaining part of the block on a fast track basis', and subsequently, the relinquishment area could also be worked out in a proper manner. Meanwhile, RIL gave notice for moving from the 2nd to the 3rd phase without any relinquishment. By July 2006, after a presentation made by RIL, DGH informed the Ministry that the MC had permitted to enter the next phase without any relinquishment, even when a 'small portion of the area' remained to be covered by 3D seismic. The Ministry raised pertinent questions as to whether the coverage of well was over the entire block for DGH to reach the conclusion of discovery extension, but failed to pursue this aspect further. Instead, they chose to

focus on getting a certification from DGH that the contractor's claim was correct, and thereafter on timelines for appraisal of discoveries premised on the MC's approval of the entire contract area as discovery area on 11 July 2006. After concerns expressed by the Minister, PNG as to the consistency with the PSC provisions, the case was referred to a Committee under the Additional Secretary, MoPNG and then finally approved by the Minister in July 2008, but communicated to DGH in February 2009 only.

56. In Audit Report No. 19 of 2011-12, C&AG had pointed out that, contrary to PSC provisions, the Contractor was allowed to enter the second and third Exploration Phases without relinquishing 25 *per cent* each of the total Contract Area 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.

57. 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). 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. 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. According to Audit, 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*”. 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.

58. 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 discover. 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.

59. Further, MoPNG approved, on 31 July 2008, 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.

60. 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 this regard, Audit noted that the DGH interpretation regarding 'discovery area' was not in line with PSC provisions 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 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 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 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.

61. 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, this would

result 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.

62. Thus, PSC provisions as above, MC acceptance of discovery area in July 2006 and MoPNG decision of July 2008 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 exploration wells and six appraisal wells of discoveries resulting from these exploration wells.

63. 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.

64. 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".

65. 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.

66. Audit replied to MoPNG's 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 stated 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.

67. 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 in 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.

- 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.

68. Thus, in view of the PSC provisions as discussed above, MC acceptance of discovery area in July 2006 and MoPNG decision of July 2008 , Audit is of the opinion that further exploration activities in the 'discovery area' (which included drilling of eight exploration wells and six appraisal wells of discoveries resulting from these exploration wells at an expenditure of US$ 427.03 million) was improperly carried out at the risk of revenue of the commercial discoveries made in the Block.

69. Audit, therefore, recommended that 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.

70. MoPNG replied in its reply to the PAC stated that:

"Under Article 4.1 and 4.2, the Contractor is allowed to retain 75% and 50% of the Contract Area and also the 'discovery area' and 'development area'. In the instant case, the Contractor opined under Article 1.39 of the

PSC that petroleum existed in the entire Contract Area. Hence the Contractor was allowed to retain the entire area as discovery area

It is pertinent to mention that finally at the end of appraisal periods the Contractor has been allowed to retain only the ‘development area’ for production of petroleum. Remaining area other than development area to the extent of 6199 square kilometres has been relinquished.

The PSC does not provide for the Management Committee or the Government to demarcate or determine the discovery area for the purpose of the Contractor’s relinquishment obligation under Article 4.1 and 4.2, as such determination is not possible at that stage before completion of appraisal. Based on the opinion of the Contractor as provided in article 1.39 of PSC, the discovery area was allowed to be retained by the Contractor for a limited time period till a development plan was approved. There is no possibility to produce petroleum from discovery area unless the development area is demarcated after due appraisal activities.

Discovery under Article 1.38 refers to a deposit of petroleum not previously known to have existed which can be recovered at the surface. There can by multiple petroleum deposits one below / above the other in different horizons and finding of each deposit is technically treated as a discovery. The term discovery area / development area is with reference to a given discovery in a particular reservoir and there can be overlapping laterally or vertically different discovery areas / development area associated with multiple discoveries. A prohibition of exploration in a discovery area in a different horizon would unjustifiably hinder the search for more and more petroleum within the country.

Immediately after a successful discovery, the delineation of the extension of petroleum is not possible unless appraisal is completed, and definite timelines have been stipulated in PSC for appraisal so that the Contractor would not be able to prolong retention of Contract Area under the guise of appraisal. The PSC under Article 1.39 permits the Contractor to identify a tentative discovery area based on the discovery well and seismic studies which the Contractor is permitted under Article 4.1 and 4.2 to retain for a temporary period till further appraisal and delineation of the development area are done.

As the Management Committee would not have adequate data for delineating the area holding petroleum potential until appraisal is completed, the PSC does not require the Management Committee to approve the discovery area but requires the Contractor to obtain the approval of the Management Committee on the determination of development area under Article 6.6 (c). Discovery area is the indicative area identified by the Contractor based on a discovery well and seismic surveys. Development area is an area demarcated by the Management

> Committee based on the results of appraisal program, in respect of which a development plan has been proposed by the Contractor. Thus the Development area is determined by the results of appraisal and scope of development plan on which the Contractor is willing to invest his funds.
>
> Based on the technical merits the contractors in some other blocks vis RJ-ON/6 (Operator-Focus), KG-DWN-98/2 (Operator-ONGC) have been allowed to retain more area after expiry of second exploration phase".

71. Article 4 of the PSC provides for retention of discovery area and development area after the period of exploration phase-I, phase-II and phase-III. The discoveries were made in exploration phase-I in Mio-pliocene zone and were extending in channel levee complex. As per article 1.39, contractor was allowed to keep entire area as discovery area subject to conducting 3D seismic survey in all the remaining areas.

72. The discoveries made in phase-II were in different stratigraphic level i.e. plio-pleistocene zone and were in channel levee complex. The contractor was carrying out appraisal in these zones subsequent to making three discoveries in phase-II.

73. In the phase-III period, the discoveries have been made in different stratigraphic level i.e. Pliocene and Mesozoic formations which is different from that of the phase-I and phase-II. The contractor was allowed to carry out appraisal activities for these discoveries. The total appraisal period allowed for the gas discoveries is three years from the date of notification.

74. Hence, all the 19 discoveries made in the block during the exploration period were in accordance of the PSC and the relinquishment was carried out at the end of the appraisal period. The final area retained at the end of the appraisal period of all the discoveries is 1446 sq. km.

75. The discoveries made in phase-I were in plio-pleistocene zone and the discovery area demarcated is related with the plio-pleistocene stratigraphic level. However, the area demarcated separately in subsequent phase i.e. 5445 sq. km. is related with different stratigraphic level. Therefore, from above it is evident that the discovery area is

related with the discovery made at specific stratigraphic level and retention of discovery area was in accordance with article 1.39 of PSC.

76. As explained earlier, discovery area is related with the discovery made at specific stratigraphic level and retention of discovery area was in accordance with article 1.39 of PSC. Hence, in the same block there can be different discovery area for discoveries at different stratigraphic level and therefore RIL retained the entire area as discovery area in 2004 for appraisal of mio-pliocene strata. Subsequent discoveries were made in different stratigraphic level and accordingly operator proposed for retention of discovery area in subsequent phases.

77. The objective of the appraisal program is to delineate the extent of the continuity of the reservoir. Operator has carried out seismic work and drilled exploratory wells which has fulfilled the objective of appraisal program.

C. Deficiencies in pre-qualification process

78. According to Audit, for pre-qualification of vendors for issue of Request for proposal (RFP) for charter hiring of Floating Production Storage and Offloading facility (FPSO), a VQC analysis was prepared on the basis of details of respective firms downloaded from the internet and sent to OC on 4 September 2006 for approval. The supporting documents to this VQC analysis were not found on record, as they were not maintained by the operator. Aker Floating Production ASA (AFP)/Aker Group (the finally successful bidder) was selected for issuing Request for Proposal (RFP), despite lack of any experience of operating and maintaining an FPSO. Also there was no specific criterion for assessment of financial capability.

79. Audit further stated that, AFP should have been disqualified at the RFP stage, as it had not fulfilled many significant RFP requirements, e.g.

- Non submission of Technical and Commercial checklists;
- Non submission of preceding three financial years' audited financial statements; instead, AFP enclosed the Aker group's annual report for the last two years;

Aker Floating Production (AFP) was incorporated only on 14 March 2006, i.e. between the EOI invitation in January 2006 and VQC analysis in September 2006.

- some vital information regarding technical competence of the bidder was not submitted by AFP. This included quality plan, inspection and test plan, and HSE details. Despite these, AFP was declared technically qualified.

The operator's response (furnished through MoPNG in July 2011) on these aspects is not tenable, as explained below:

- The operator's contention that the checklists were enclosed with the RFP mainly to ensure that the bidders were able to ensure the completeness of their bids, is unacceptable as the bidder, AFP, had not fulfilled many significant requirements as indicated in the checklists. The operator obtained the checklist on 4 November 2006, i.e. after the bid opening date.

- The operator's reply that AFP had submitted the audited financial statements for two years, which provided three years' financial results as required in the RFP, is incorrect and therefore unacceptable. The bidder, AFP, had enclosed financial statements of the Aker group as a whole for two years (2004 and 2005), while AFP itself was formed only in 2006. Further, against the column of parent company guarantee, AFP had indicated that the parent company guarantee would not give RIL remedies against the parent guarantor beyond the remedies which were available against the contractor under the contract. Subsequently, AFP became the parent company and contracts were awarded to its subsidiary companies.

D. <u>Irregular selection of AFP</u>

80. Except for the bids of two vendors (AFP and SBM), all the other six bids received by 25 October 2006 were technically rejected on 2.12.2006. We found that:

- Technical qualification was done (6.12.2006), not of the bids originally received by 25 October 2006, but of the revised bids of AFP and SBM, submitted after discussions held with them (including a meeting in Oslo in November 2006). In addition to being contrary to Clause 5.6 of instruction to Bidders in the RFP, which clearly forbids any revision in bids after the bid due date, allowing changes to bids by selected (and not all) bidders is against the spirit of obtaining reasonable prices through competitive tendering.

- The operator did not fix a bid opening date in advance, nor were representatives of bidding firms invited for the bid opening, so as to ensure transparency and fairness.

- we did not find the priced bids of technically unqualified bidders sealed or intact, so as to have assurance that these were not opened.

- Interestingly, the priced bid of AFP bid was not was not signed by the bidder (as required); the possibility of modification of priced bid cannot be ruled out.

- The price quotes for optional items by AFP were left blank for 'open book' cooperation with RIL.

  RIL's response, furnished by MoPNG, indicated (July 2011) that, out of the eight bids, seven bids (including SBM - subsequently) were rejected on the following grounds;

- Permanently moored system offered against requirement for disconnectable system (Nortech & SMB);

- Various deliverables required as per RFP were not submitted (Fred Olsen);
- DP vessel offered instead of a moored system (FPSOcean);

- Silent on safe abandonment of risers in bad weather, FFP not offered, hull life not determined (Compass Energy EPS);

- Specific details not provided, geo-technical & geo-physical studies not included (EMAS); and

- Bidder expressed inability to comply with operator's requirement with regards to scope of work, responsibilities, schedule and commercial mechanism (Sea Production).

81. This wholesale disqualification leads us to question the entire pre-qualification process. The contention of the operator (forwarded through MoPNG) regarding selection of AFP over others is not tenable for the following reasons:

- The information on availability of relevant resources, know-how and expertise within Aker Group was the subject of public announcements and part of process for Aker's qualification for listing on the Oslo Stock Exchange, and that the operator had reviewed the financial background and technical experience for award of contracts is not acceptable, as the acceptance of qualifications for listing on Stock Exchange is not related to the fulfillment of qualification and experience criteria specified in the RFQ.

- ABO, a subsidiary of AFP, was also established in July 2006 for operating the FPSO for AFP; the contract with RIL was their first operation and maintenance contract. All other bidders, including those experienced in that field, were rejected during technical evaluation.

- Operator's reply that AFP had suggested 'open book' cooperation for optional items on the basis that certain salient details could only be finalized during detailed engineering, is not tenable, as the approved procurement procedure does not provide for it. In any case, the operator should have finalized the engineering details, before issuing the RFP.

82. According to audit, as in terms of the PSC, the full cost is recoverable by the operator. Hence, it is incumbent on the operator to ensure that a fully transparent, and cost-effective process is adopted which gives assurance to the Government that costs have indeed been minimized.

83. When asked whether the Ministry reviewed indepth the award of 10 specific contracts based on single financial bid to Aker Group Companies, as suggested by the audit, the Ministry replied:

> "The review of procurement contracts is a specialized audit function which cannot be executed by any other agency than audit.
>
> Ministry relies on audit review done by CAG and other auditors. Government relies on auditors for disallowing any expenditure for the purpose of determining Government Take. MOP&NG / DGH action would depend on specific CAG recommendation and cannot take the role of auditor. In case Audit is able to report any unfair practice causing specific loss to Government, the loss will be reduced in the contract cost for computation of Government Take. CAG’s qualitative comments have been contested by the Contractor who has given detail replies. Therefore the audit exceptions should be concluded with the financial impact and such audit conclusion can be drawn only by the team which carried out the detailed audit".

84. The Ministry in their presentation made before the Committee on 21.03.2016 have stated as under:

- Operating Committee monitored the contract award as per Appendix F of PSC

- CAG did not quantify any financial impact, in accordance with CAG's Reporting Standards and Accounting and Audit Standard 28 of ICAI.

- CAG's Reporting Standards (Article IV) requires that the audit report, in cases of adverse opinion, quantifies the financial effect on the financial statements.

- Audit and Accounting Standard 28 of ICAI stipulates: "Whenever the auditor expresses an opinion that is other than unqualified ..... unless impracticable, a quantification of the possible effect(s), individually and in aggregate, on the financial statements should be mentioned in the auditor's report"

- Audit report did not find any affiliated transaction or fraud to invalidate the integrity of procurement".

E. <u>Proposal for Declaration of Commerciality (DoC)</u>

85. 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.

86. Evaluation of DoC is a technical-cum-economic analysis based on 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.

87. 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".*

88. 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*."

89. 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.

90. 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.

91. 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.

92. 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 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".*

93. 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.

94. Audit observed 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.

95. 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.

96. 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".*

97. In this regard, Audit stated 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....".*

98. 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".*

99. MoPNG in its reply 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*.

100. 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.

101. 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.

102. Audit, therefore, recommended that MoPNG may develop consistent and uniform parameters for evaluating commerciality of discoveries.

103. MoPNG it its Action Taken Notes Stated that DOC in respect of D29, D30 and D31 was not recommended by DGH for review for lack of DST. The Contractor appealed against the view to MOP&NG. The issue has been reopened for review in view of the petroleum potential of the discoveries in an energy starving country. A decision will be taken by competent authority keeping in view of the PSC provisions and the interest of energy security. Government is considering a transparent policy guidelines regarding testing requirements for the existing and future cases.

104. When asked that how does Ministry justify the inordinate delay in finalization of the issue regarding DoC of D-29, D-30 and D-31 discoveries in view of NELP's objective of expeditious monetization of hydrocarbon resources, the Ministry replied that the DoC of D-29 , D-30 and D-31 was not reviewed by Management Committee in absence of production tests which provide sustainable production levels from the reservoir which is required as per PSC. Contractor was of the different opinion that test other than DST in deepwater which are non-conventional also provides the sufficient basis for evaluation of DoC. The similar contentions were also raised by other operators in different deepwater blocks. Due the difference of views between DGH and contractor Govt. considered the case and a decision in this regard is taken by CCEA wherein the contractors has been given relaxation for conducting DST in these blocks by capping the such test cost upto US$ 15 million per test. Because of this highly techno-commercial decision in the interest of development of discovered deepwater resources, it took time. The other option available with the Govt. to get these areas relinquished. Allowing such test is in the overall interest of development of deepwater resources which was also mandate of New Exploration Licensing Policy.

105. Govt. has issued a policy for testing requirement. According to that policy the operator has opted for conducting DST. The operator has completed DST for D29 and D30 discoveries and has relinquished D31 discovery in accordance with policy. In terms of the policy the contractor has to submit revised DOC for D29 and D30 by 28th April 2016.

F. <u>Policy on Testing Requirements for discoveries in NELP blocks</u>

106. The Cabinet Committee on Economic Affairs (CCEA), chaired by the Prime Minister Shri Narendra Modi, on 29.04.2015 approved a clear policy on testing requirements for discoveries made under New Exploration and Licensing Policy (NELP) Blocks. The policy will settle the long pending issue with regards to 12 discoveries in five blocks pertaining to ONGC (six discoveries) and Reliance Industries (six discoveries) but will also establish a clear policy for the future. The policy will also help in bringing out transparency and uniformity in decision making as against case by case

approach in the past. The approval given by CCEA would provide a way forward for development of these 12 discoveries with associated gas reserves of around 90 Billion Cubic Meter (BCM) which would be valued at over Rs.one lakh crore at the current gas price of US $ 4.66 / Million British Thermal Unit (mmbtu) on Gross Calorific Value (GCV). The policy approved by CCEA allows the contractors to choose one of the following three options with regards to discoveries which are stuck on account of testing requirement:

- Relinquish the blocks
- Develop the discoveries after conducting Drill Stem Test (DST) with 50 percent cost of DST being disallowed as penalty for not conducting the test on time. The cost recovery for carrying out DST would be capped at US $ 15 million.
- Develop the discoveries without conducting DST in a ring fenced manner.

If the contractor does not opt for any one of these options suggested above within 60 days of the CCEA approval then the area encompassing these discoveries shall automatically be relinquished.

G. <u>Viability of Optimized Field Development Plan (OFDP)</u>

107. The Contractor submitted (July 2008) Development Plan (DP) of nine Satellite Gas Discoveries (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.

108. The Contractor submitted (December 2009) an OFDP for four satellite discoveries 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).

109. 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. 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. 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.

110. 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.

111. 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".

112. 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.

113. Audit stated that:

- 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".

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

115. MoPNG in its Action Taken Notes stated that Based on the learning of several discoveries over the years DGH has developed a Standard Operating Practice (SOP) for evaluating the FDP for discoveries. The DOC / FDP are evaluated by discounting the

entire cost and revenue at 10% and all the discoveries yielding a positive NPV are considered fully viable. In case of discoveries which are not fully viable, the viability is evaluated based on marginal principle: discoveries yielding positive NPV considering future costs excluding taxes and future revenue are accepted. Globally economic evaluation is done based on this incremental principle.

The above principles are consistently followed in all cases.

> "MOPNG in its reply has stated that constituted body "Standing Committee on Petroleum industries practices" has submitted the guidelines on Good International Petroleum Industry Practices (GIPIP. The guidelines are a compendium of all good practices being followed in different parts of the world for carrying out petroleum operations. Team constituted by MOPNG for framing the "Good International Petroleum Industries Practices" has identified the best practices being followed for all technical and commercial activities under the production sharing contract. The report has been submitted to the Govt. for adoption and notification

116. The Ministry in their presentation made before the Committee on 21.03.2016 have stated as under:

- Post vendor-contractual agreements between the Operator and the vendor validly amended the original vendor-contract
- Audit report did not point out any legally tenable ground for cost disallowance, such as
- Affiliated transactions to the undue advantage of Contractor
- Any incidence of fraud
- Costs not supported by payment evidences
  Operator's response is that expenditures were incurred in the interest of Petroleum Operations"

III. GRANT OF CONCESSIONS AGAINST CONTRACTUAL TERMS

A. Contract for Engineering, Procurement, Installation and Construction of offshore facilities.

117. 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.

118. 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.

119. 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.

120. 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.

121. 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.

122. 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.

123. Audit concluded 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, 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 . 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.
>
> • 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".

124. 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.

125. 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. 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'.

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.

The Audit Team's opinion does not consider the practical difficulties and issues which led to this operational decision taken by the Operator".

126. Audit responded that:

"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".

127. 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.

128. 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.

129. 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.

130. 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.

131. 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. 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. 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.

132. 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".

133. Therefore, Audit suggested that 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.

134. MoPNG in its action taken notes stated that:

> The audit exception was notified to the Contractor. The issue deals with additional costs / resources granted by the Operator to the vendor M/s Allseas Marine Contractors to mitigate delays in the execution of EPIC contract by way of waiving of LD, granting of additional incentives, assistance etc.
>
> The clarification given earlier by MOP&NG on the applicability of Section 3.2 (ix) is again reiterated. The section disallows payments made by the Operator to another party by way of penalty / damages for non-fulfillment of contractual obligations on the part of the Operator towards the other party (e.g. take or pay damages paid to buyers of petroleum for non supply of petroleum or cost of unfinished work program paid to GoI for non completion of committed work program). Section 3.2 (ix) is not applicable in the instant case as the non-fulfillment of contractual obligation is on the part of the vendor and not on the part of the Operator.
>
> The audit has not found any issues as to the MOP&NG's suggestion that the agreement between the Operator and vendor on enhancement of payment itself constituted an amendment of the vendor contract. Hence additional payments made by the Operator to the vendor formed part of the amended vendor contract.
> The break-up of details of Euro 200 million recommended for disallowance are also not provided in the audit report.
>
> In response to the request of MOP&NG to CAG to specifically comment whether any fraud or affiliated transactions causing undue benefits to the Operator / Contractor was noticed in these transactions, the audit has not reported the occurrence of any such event.
> The audit's final view on this issue, considering the abovementioned facts and also the response of the operator on this audit observation, would be implemented as per the provisions of PSC.

135. The Ministry in their presentation made before the Committee on 21.03.2016 have stated as under:

- Post vendor-contractual agreements between the Operator and the vendor validly amended the original vendor-contract
- Audit report did not point out any legally tenable ground for cost disallowance, such as
- Affiliated transactions to the undue advantage of Contractor
- Any incidence of fraud
- Costs not supported by payment evidences
  Operator's response is that expenditures were incurred in the interest of Petroleum Operations

B. 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:

(a) Extension of Dry Docking life

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.

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".

136. 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".

137. 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.

Audit did 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.

- 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.

- 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.

138. 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.

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

140. MoPNG in its Action Taken Notes stated that:

"The audit exception is that the Contractor paid an additional amount of US $ 17.36 million to M/s Aker for increasing the dry docking life of FPSO from 10 years to 15 years. Audit has recommended disallowing the entire cost, as the charter hire was procured based on the technically accepted single bid and that the charter hire contract itself was for 10 years.

The Operator had replied (as quoted by CAG): "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.

In response to the request of MOP&NG to CAG to comment whether any fraud or affiliated transactions causing undue benefits to the Operator / Contractor was noticed in these transactions, the audit has not reported the occurrence of any such event.

However, the audit's final view on this issue, considering the abovementioned facts and also the response of the operator on this audit observation, would be implemented as per the provisions of PSC".

141. The Ministry in their presentation made before the Committee on 21.03.2016 have stated as under:

- Post vendor-contractual agreements between the Operator and the vendor validly amended the original vendor-contract
- Audit report did not point out any legally tenable ground for cost disallowance, such as
- Affiliated transactions to the undue advantage of Contractor
- Any incidence of fraud
- Costs not supported by payment evidences
  Operator's response is that expenditures were incurred in the interest of Petroleum Operations

C. <u>Increased cost for expediting deliveries and early mobilization of commissioning team and extension of date of first production of oil and gas</u>

142. 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 that the DFPO could be between 7 April 2008 and 27 April 2008.

143. 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.

144. 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 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.

145. 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. 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.

146. 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 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 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”.

147. Audit reasoned:

- 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.

148. Audit, therefore, recommended that the cost recovery of US$ 45 million incurred by the Operator on account of compensation / incentives to sub-vendors may be disallowed.

149. MoPNG in its action taken notes stated that CAG has recommended disallowance of US $ 45 million incurred by the Operator towards incentives / compensation paid to sub-vendors for expediting delivery of materials / services so as to enable advancing of petroleum production. Details of US $ 45 million recommended for disallowance are not reported in the audit report. The final audit exception has been notified to the Contractor and the reply is awaited. CAG has not reported any fraud or affiliated transactions causing undue benefits to the Operator / Contractor noticed in these transactions. As cost recovery is being done in respect of the actual cost incurred at arms' length by the Contractor for the petroleum operations and no undue advantage to the Contractor has been established. However, the audit's final view on this issue, considering the abovementioned facts and also the response of the operator on this audit observation, would be implemented as per the provisions of PSC.

150. The Ministry in their presentation made before the Committee on 21.03.2016 have stated as under:

- Post vendor-contractual agreements between the Operator and the vendor validly amended the original vendor-contract
- Audit report did not point out any legally tenable ground for cost disallowance, such as
  - Affiliated transactions to the undue advantage of Contractor
  - Any incidence of fraud
  - Costs not supported by payment evidences

  Operator's response is that expenditures were incurred in the interest of Petroleum Operations

D. <u>Fabrication and installation of living quarters</u>

151. 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.

152. 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.

153. The Operator replied that (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".*

154. 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".

155. 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.

156. 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.

157. Audit observed 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.

158. MoPNG in its Action Taken Notes stated that CAG has recommended disallowance of US $ 15 million incurred by the Operator towards refurbishment of existing living quarters and installation of additional living quarters in the FPSO, on the ground of avoidable cost. It could be seen that the Contractor has actually incurred the expenditure on petroleum operations. However CAG differs with the Operator on the requirement of the expenditure incurred. CAG has not reported whether any fraud or affiliated transactions causing undue benefits to the Operator / Contractor was noticed in these transactions. However, the audit's final view on this issue, considering the abovementioned facts and also the response of the operator on this audit observation, would be implemented as per the provisions of PSC.

159. The Ministry in their presentation made before the Committee on 21.03.2016 have stated as under:

- Post vendor-contractual agreements between the Operator and the vendor validly amended the original vendor-contract
- Audit report did not point out any legally tenable ground for cost disallowance, such as
- Affiliated transactions to the undue advantage of Contractor
- Any incidence of fraud
- Costs not supported by payment evidences
  Operator's response is that expenditures were incurred in the interest of Petroleum Operations

IV. IRREGULAR PAYMENTS

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

160. 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, 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.

161. 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.

162. 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.
> • As these cranes require a lot of handling by L&T Ltd., the Operator was justified in the payment of compensation to the vendor".

163. 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”.

164. Audit observed 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".

165. Audit felt that 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.

166. MoPNG in its Action Taken Notes stated that "CAG has recommended disallowance of Rs 22.70 million paid to M/s Larsen & Toubro in a cost plus contract. From the comments of Audit, it is seen that the expenditure was actually incurred by the Operator under a cost plus contract. CAG has not responded to the MOP&NG query to suggest the provision of PSC under which such cost can be disallowed when the

Contractor had actually paid the amount to the vendor. The final audit exception has been notified to the Contractor. CAG has not reported whether any fraud or affiliated transactions causing undue benefits to the Operator / Contractor was noticed in these transactions. However, the audit's final view on this issue, considering the abovementioned facts and also the response of the operator on this audit observation, would be implemented as per the provisions of PSC".

167. The Ministry in their presentation made before the Committee on 21.03.2016 have stated as under:

- Post vendor-contractual agreements between the Operator and the vendor validly amended the original vendor-contract
- Audit report did not point out any legally tenable ground for cost disallowance, such as
- Affiliated transactions to the undue advantage of Contractor
- Any incidence of fraud
- Costs not supported by payment evidences

Operator's response is that expenditures were incurred in the interest of Petroleum Operations".

B. <u>Payment of INR 1110.90 million as compensation on Free Issue Material</u>

168. 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).

169. 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.

170. 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.

171. 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).

172. 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.

173. 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”.

174. 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".

175. Audit reasoned 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".

176. Audit, therefore, suggested that 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.

177. MoPNG in its Action Taken Notes stated that "the issue deals with the procurement philosophy of the Contractor not being in line with the views of audit officers. It is seen from the audit report that that Rs 1110.9 million was actually incurred by the Contractor and no affiliated transaction or fraud causing undue benefit to the Operator / Contractor was reported. In such circumstances, no legally tenable ground could be seen to disallow the costs. However, the audit's final view on this issue, considering the abovementioned facts and also the response of the operator on this audit observation, would be implemented as per the provisions of PSC".

178. The Ministry in their presentation made before the Committee on 21.03.2016 have stated as under:

- Post vendor-contractual agreements between the Operator and the vendor validly amended the original vendor-contract
- Audit report did not point out any legally tenable ground for cost disallowance, such as
- Affiliated transactions to the undue advantage of Contractor
- Any incidence of fraud
- Costs not supported by payment evidences

Operator's response is that expenditures were incurred in the interest of Petroleum Operations

C. <u>Classification of Start-up and Production Bonuses as part of recoverable costs</u>

179. 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.

180. 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.

181. As per Audit, 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.

182. 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. "

183. 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".

184. Audit, however, did 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".

185. According to Audit, 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.

186. MoPNG in its Action Taken Notes stated that "CAG has recommended disallowance of US $ 12.48 million incurred on Start-Up and Production Bonus paid to employees engaged in the block on the ground that the bonuses were one-time payment of an ad hoc nature. Being expenditure actually incurred in petroleum operations, cost disallowance may be reconsidered. However, the audit's final view on this issue, considering the abovementioned facts and also the response of the operator on this audit observation, would be implemented as per the provisions of PSC".

187. The Ministry in their presentation made before the Committee on 21.03.2016 have stated as under:

- Post vendor-contractual agreements between the Operator and the vendor validly amended the original vendor-contract
- Audit report did not point out any legally tenable ground for cost disallowance, such as
- Affiliated transactions to the undue advantage of Contractor
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Operator's response is that expenditures were incurred in the interest of Petroleum Operations".

V. AWARD OF CONTRACT

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

188. 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.

189. 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.

190. 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.

191. 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.

192. 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.*

193. Audit stated that:

- 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.

194. 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.

195. According to Audit the contentions of the operator have to be view in light of the following:

- 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.

196. Audit, therefore, concluded that 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.

197. MoPNG in its Action Taken Notes stated that "the audit exception is that the Operator awarded charter hire of an offshore deep water drilling rig to M/s. Transocean Offshore International Ventures Limited (1stContract) at an operating day rate of US$ 0.32 million and later awarded a 2ndContract again to Transocean for the same rig at an operating day rate of US$ 0.48 million per day, commencing from the expiry of the period for charter-hire under 1stContract. It is the audit's view that the higher rate could have been avoided had the 1st Contractor been entered for the required longer period. This can be at best considered as inadequate appreciation of requirements and lack of proper planning by the contractors. The contractors may not be aware of future behavior of market for hiring of services. Audit may reconsider this disallowance. However, the audit's final view on this issue, considering the abovementioned facts and also the response of the operator on this audit observation, would be implemented as per the provisions of PSC".

198. The Ministry in their presentation made before the Committee on 21.03.2016 have stated as under:

- Post vendor-contractual agreements between the Operator and the vendor validly amended the original vendor-contract

- Audit report did not point out any legally tenable ground for cost disallowance, such as
- Affiliated transactions to the undue advantage of Contractor
- Any incidence of fraud
- Costs not supported by payment evidences

Operator's response is that expenditures were incurred in the interest of Petroleum Operations

B. <u>Bonus paid for time saved during rig movement</u>

199. 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".*

200. 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.

201. 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".

202. Audit reasoned:

- 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".

203. 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.

204. MoPNG in its Action Taken Notes stated that "the audit observation is that US $ 2.83 million paid to M/s Transocean as bonus for efficiency achieved by rig movement done with the BOP in hanging position, was not allowable for cost recovery. The amount involved was actual expenditure incurred in petroleum operations in a transaction that was not reported by audit to be an affiliate transaction or transaction unduly benefitting the Operator / Contractor. However, the audit's final view on this issue, considering the abovementioned facts and also the response of the operator on this audit observation, would be implemented as per the provisions of PSC".

PANNA-MUKTA AND MID & SOUTH TAPTI FIELDS

VI. INTRODUCTION

205. The Panna-Mukta (primarily an oil field) and Mid & South Tapti (gas field) are shallow water fields located in the offshore Bombay basin, were initially discovered and operated by ONGC. Following the 1992 offering of small and medium sized oil and gas fields for development, GoI awarded (February 1994) the Panna-Mukta and Mid & South Tapti contract areas, which were discovered by ONGC, to a consortium comprising of ONGC (40 *per cent*), RIL (30 *per cent*) and Enron Oil & Gas India Ltd-ENRON (30 *per cent*) (together called Contractor) under a production sharing arrangement. The PSC was signed in December 1994 between the GoI and the Contractor. The Contractor formed an unincorporated joint venture (JV) called PMT JV. In February 2002, British Gas Exploration and Production India Limited (BGEPIL) acquired ENRON's 30 *per cent* stake in the JV and became a party to the PSC. Presently, the field is jointly operated by ONGC, RIL and BGEPIL.

VII. DEVELOPMENT OF PANNA-MUKTA AND TAPTI FIELDS

206. At the time of bidding, the Panna-Mukta contract area was a discovered and partially developed oil producing field of ONGC[17] and Mid & South Tapti contract area was a discovered gas field by ONGC. Both the Contract Areas were developed by the JV in two phases.

In Panna-Mukta, Initial Plan of Development (IPOD) project was executed between 1995-99 wherein three wellhead platforms (PC, PF and PG) were installed. In the second phase of development, i.e. Expanded Plan of Development (EPOD), executed between 2004 and 2007 two wellhead platforms (PH and PJ) were installed.

Similarly, Mid & South Tapti Contract Area was developed in two phases *viz*., IPOD and New Revised Plan of Development (NRPOD). The IPOD project was executed during 1995 to1997 wherein JV installed three wellhead platforms *viz*. STA, STB, STC in South Tapti field along with associated processing & transportation

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[17] *ONGC installed 5 wellhead platforms (viz. PA, PB, PD, PE and MA wellhead platform) for production and handed over to PMT JV at the time of signing of PSC (December 1994).*

facilities. The NRPOD project was executed during March 2005 to August 2007 wherein JV installed one wellhead platform MTA in Mid Tapti field, and additional processing and transportation facilities for handling increased production. JV installed one wellhead platform STD in South Tapti field in August 2006 to maintain the plateau of production.

VIII. ISSUES AND HIGHLIGHTS OF AUDIT FINDINGS

A. Report No. 19 of 2011-12

207. The C&AG in their report have scrutinised records of the Ministry of Petroleum and Natural Gas (MoPNG) and the Directorate General of Hydrocarbons (DGH) in respect of a sample of 20 PSCs covering the period from 2003-04 to 2007-08, and also conducted supplementary scrutiny of records of the operators of 4 blocks/fields including Panna-Mukta and Mid & South Tapti covering the two year period 2006-07 and 2007-08.

208. On the issue of *Financial and Operational Performance*, the summary of sharing of profit petroleum between GoI, ONGC and the private parties from 2000-01 to 2008-09 in respect of the Panna-Mukta and Mid & South Tapti fields shows that the IM in respect of the Panna Mukta field crossed 2.0 only in 2004-05 (as per MoPNG's calculations) and moved to the second slab (GoI share moving up from 5 to 15 per cent), while the IM in respect of the Mid & South Tapti field still remains in the lowest slab (below 2.0 with GoI share of 20 per cent). With more than 13 years of operation of the PSC till March 2008, the IM still remains in the first and second slabs. In the opinion of Audit, the prospect of IM rising to 3.5 (resulting in GoI share of 50 per cent) over the remaining contract period is remote; thus further calling into question the appropriateness of the IM slab-based sharing of profit petroleum. In the opinion of Audit, the *delay in finalization of norms* to determine wellhead price of gas for purposes of royalty compelled to make observation that GoI should have treated the royalty payment from these fields as provisional, pending the finalization of norms for post-wellhead costs. Even if this had not been treated as provisional from the start of gas production in 1997/1998 (although the modalities of calculation were reflected in the royalty statements submitted to MoPNG/DGH and this issue could have been flagged right away), GoI should have treated the royalty payment as provisional at least from January 2002, when DGH highlighted the problem for MoPHG's consideration. Further,

the Audit commented that the results of MoPNG's efforts to simplify/clarify the system for calculation of post-wellhead expenses and remove ambiguities therein were awaited. On the topic *Crude oil and Gas sales*, it has been observed that the key issue regarding pricing of gas sales from PMT is that the MoPNG and its nominee (GAIL) failed to comply with the terms of the PSC during 2005-08 with regard to the pre-determined pricing formula. Not honouring the PSC formula severely affects the sanctity of the contract (which is to be maintained by all parties), which is highly undesirable from the long-term perspective of all contracting parties; on condensate loss during transportation, the PSC for Mid and South Tapti is silent on the treatment of condensate; and on non-signing of Crude Oil and Sales Agreement (COSA), the Ministry has stated that the suggestions of C&AG on COSA would be examined. This particular issue had been highlighted in the earlier CAG's Audit Reports of 1996 and 2005. The Audit has urged that a quick decision be taken, since nearly 2/3rd of the terms of the PSC is already over. The C&AG on *findings in respect of Panna-Mukta* has observed that even after lapse of more than a decade, the JV had not completed many of the development activities committed under Appendix G of PSC and also covered aspects of cost recovery and instances of excess expenditure. As regards *findings in respect of Mid and South Tapti*, the C&AG has found that with respect to non-completion of committed work programme and delays, there were no firm plan for installation of the remaining 5 wellhead platforms committed in the PSC; on the issue of cost recovery in excess of Cost Recovery Limit (CRL) further progress was awaited; and have highlighted the instances of excess expenditure and cost recovery. Further, the C&AG has listed and briefed on the common issues of excess expenditure and cost recovery relating Panna-Mukta and Mid & South Tapti fields. On the issue of Notional Income Tax, the Audit has urged that the issue of downward revision in corporate income tax rates and corresponding benefit to the contractors, should be highlighted and included in the ongoing arbitration proceedings invoked by the contractors.

B. <u>Report No. 24 of 2014</u>

209. The C&AG in their report have covered the four years period from 2008-09 to 2011-12 and contains the results of the Performance Audit on 'Hydrocarbon Production Sharing Contracts' at the Ministry of Petroleum and Natural Gas (MoPNG) and the

Directorate General of Hydrocarbons (DGH) with respect to blocks/fields including that of Panna-Mukta and Mid & South Tapti.

210. The particulars of *physical and financial performance* of Panna-Mukta and Mid & South Tapti contract areas have been detailed and have covered the contract cost, revenue and profit petroleum to the GoI during the period under review. The PSC stipulates for *execution of committed work programme (Appendix G of PSC) and Cost Recovery Limit (CRL)* of US$ 577.5 million and US$ 545 million for Panna-Mukta and Mid & South Tapti respectively. In this regard, the JV is yet to execute the committed work programme of Mukta-B development in Panna-Mukta field and install 5 well platforms in Mid & South Tapti field. The brief on *issues relating to Arbitration* inter-alia include arbitration notice served by the partners RIL and BGEPIL (December 2010) under PSC to GoI pertaining to i) Cost Recovery provisions under Panna-Mukta and Tapti PSC, ii) Calculation of IM, iii) Amount of royalty payable under PMT PSC, iv) Amount of cess payable by Contractor to GoI, v) Amount of service tax payable under PSC, and vi) Meaning and effect of Accounting and Audit provisions.

211. The Audit while dealing with the chapter on Panna-Mukta and Mid & South Tapti have scrutinise the records of the Operator and MoPNG/DGH and grouped their findings under six categories viz. (i) Recoverable costs and cost recovery - Improper allocation of rig mobilization/demobilization charges; Excess expenditure booking of US$ 0.52 million towards Mid & South Tapti field; Cost Recovery of unconsumed production inventory US$ 26.15 million in contravention to PSC; Loss of revenue of US$ 0.09 million to GoI due to recovery of inventory carrying costs on sparable drilling inventory; and Infructuous expenditure of US$ 0.814 million on helideck and truss not used for Petroleum Operation, (ii) Deficiencies in contracting procedure and execution of Contracts - Extra expenditure on hiring of costlier rig DD-4 on assignment basis from Reliance Industries Limited (RIL) and Award of contract on nomination basis, (iii) Revenue - Petroleum saved and sold - Loss of US$ 9.92 million due to sale of gas in contravention to MoPNG directives and Gas Sales Purchase Agreement (GSPA), Loss of government revenue of US$ 0.52 million due to sale of Panna-Mukta gas in

contravention to PSC, Non fixation of transportation losses of condensate, Short payment of royalty due to incorrect computation of wellhead value, Incorrect calculation of royalty on gas due to reckoning of facilities not used for post-wellhead activities, Exclusion of ONGC's facilities for working out ratio for allocation of opex between wellhead and post-wellhead activities, and Short payment of royalty due to amortization of capex not based on upgraded reserves (iv) Petroleum operations - Preparation of Plan of Development for South West Panna without waiting for new seismic data resulted in abandoning of project and Delay in water injection project in Panna field resulting in declining production (v) Non-compliance to the PSC provisions - Delay in submission and approval of Work Programme & Budget, and (vi) issues relating to MoPNG/DGH - Non-signing of Crude Oil and Sales Agreement (COSA) between IOCL and PMT JV.

212. The C&AG have recommended following observations on the aforesaid issues as mentioned below:

(i) Improper allocation of rig mobilisation/demobilisation charges - The common expenditure should be appropriately allocated to Panna-Mukta and Tapti fields on a reasonable basis viz. actual expenditure identifiable to a particular contract area or in the ratio of expenditure on the primary activity.

(ii) Cost Recovery of unconsumed production inventory US$ 26.15 million in contravention to PSC - PMT JV may ensure that production inventory is charged to accounts only when such material is removed from inventory and used in petroleum operations as provided in the PSC.

(iii) Non fixation of transportation losses of condensate- PMT JV may expedite the fixation of transportation losses of condensate pending for last 8 years that has impacted the interest of ONGC.

(iv) Short payment of royalty due to amortization of capex not based on upgraded reserves - All facilities used for petroleum operations (pre wellhead and post-wellhead activities) may be considered for computing the wellhead value while arriving at royalty payable to GoI. The PMT JV may also work out and remit the additional royalty to GoI by considering the upgraded reserves (1997 to August 2007) for amortization of capex.

(v) Non-signing of COSA - GoI may ensure the signing of COSA between IOCL and PMT JV by expeditiously resolving the contentious issues.

IX. <u>ISSUES UNDER ARBITRATION</u>

A. <u>Report No.19 of 2011-12</u>

213. The following issues relating to Panna-Mukta and Mid & South Tapti are either under Arbitration or sub-judice and response made by the Ministry are summarised and submitted in concise form as below by the Ministry:-

(i) Issue: Delay in finalization of norms to determine well head price of gas for purposes of royalty - Specific cases of wrong inclusion of cost elements as part of post wellhead cost, in Royalty computation.

Response: Contractor has invoked arbitration.

(ii) Issue: Pricing of gas sales from PMT - GAIL (GoI nominee buying gas) refused to pay gas price computed as per PSC formula; GoIRoyalty and profit petroleum fell by Rs. 584.31 Crores.

Response: Issue under arbitration. To earn Rs. 584 crores, GAIL would have paid Rs. 2900 crore more as additional gas price.

(iii) Issue: Notional Income Tax - For calculation of Investment Multiple a notional Income Tax rate of 50 per cent used, much more than current tax rate; GoI may institute consultations under Article 15.7.

Response: Contractor has invoked arbitration. Issue will be taken up with JV for consultation through arbitration.

(iv) Issue: Non-completion of Committed Work Program in Panna Mukta - Cost Recovery Limit (CRL) of $577.5 Million, for committed work programme. JV has not completed key work commitments in respect of the Mukta field. Consequential deferment of revenue of $ 551.03 million, adverse impact on IM and GoI PP and deferment of royalty/cess. JV substituted two infill wells drilled in 2005 from the PD platform instead of the two wells from PD platform indicated in the committed work programme.

Response: Notional cost of the unfinished work program was reduced from CRL amount CRL issue is under arbitration.

(v) Issue: Cost Recovery in Panna Mukta - Cost recovery of US $ 62.5 million in excess and short remittance of GoI PP.

Response: The reversal of cost in excess of CRL was computed by DGH is Recovery of profit petroleum short paid was affected through NOC. Issue under arbitration.

(vi) Issue: Non-completion of Committed Work Programme in Mid& South Tapti.

Response: JV failed to drill wells committed in the PSC. The issue is under arbitration.

(vii) Issue: Cost Recovery in excess of Cost Recovery Limit (CRL) in Mid & South Tapti. The PSC stipulated a Cost Recovery Limit (CRL) of $ 545 million. An excess cost recovery of $ 324.35 million over the CRL.

Response: Proposal of Operator for enhancement of CRL was not agreed. Operator has invoked arbitration.

B. <u>Report No. 24 of 2014.</u>

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

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

216. The Tribunal (by a majority) passed a final unanimous Partial Award of September 2012 on Preliminary Issues holding that the arbitral tribunal has the jurisdiction to adjudicate upon the preliminary issues *(viz. royalties, cess, service tax*

and C&AG Audit).

217. The Tribunal also passed (December 2012) a final partial award in respect of Tapti PSC that

(i) the costs incurred after the Effective Date related to the construction and/or establishment of such facilities as are necessary to produce, process, store and transport petroleum from within Existing Discoveries in order to enable gas production above the Tapti IPOD Plateau Level are fully recoverable,

(ii) the determination of these costs should be made at the time approval for such work is sought or obtained from the MC,

(iii) where direct G&A and other Service Costs, are properly allocated as Development Costs, they would be recoverable in full by virtue of Article 13.1.1, 13.5 and 13.6 of the Tapti PSC unless they come within the CRL. All G&A costs and Service costs other than those which are attributable to Development Works fall outside the CRL and are recoverable in full,

(iv) indirect G&A and other Service Costs (head office and establishment expenses), where these costs are necessary for the production of gas at the IPOD Plateau Level, they would come within the CRL. If they are not, they do not come within the limit and are recoverable in full as head office and establishment expenses, and

(v) the CRL is lump sum.

218. The Arbitral Award also stated that these findings apply *mutatis mutandis*, to the Panna-Mukta PSC. The claimants had no obligation to complete the Appendix G works under either the Tapti or the Panna-Mukta PSC. The Tribunal also unanimously found that the timelines prescribed in Appendix C, Section 1, Paragraph 1.9 of the PSCs are not final and binding.

219. Present Status of Arbitration

- Final unanimous Partial Award of September 2012**:** Union of India (UoI) challenged the September 2012 award on issues of arbitrability in the High Court of Delhi. The High Court ruled (March 2013) in the UoI's favour, stating that the issues of cess, royalties, service and C&AG Audit are not arbitrable and that Part-I of the Arbitration and Conciliation Act, 1996 is not expressly or impliedly excluded in the PSCs by the parties. This order was challenged by the Claimants (BGEPIL and RIL) in the Supreme Court vide SLP (civil) 20041 of 2013. Supreme Court overruled and set aside the conclusion of the High Court and decided (May 2014) the case in favour of BGEPIL and RIL. UoI has filed a review petition with the Supreme Court of India.

- Final Partial Award of December 2012: The award dated 10 December 2012 on CRL issue was also challenged by UoI under section 34 of the Arbitration and Conciliation Act, 1996 in Delhi High Court on 02 January 2014.
- Mandate of Mr. Peter Leaver: Considering the conduct of Mr. Peter Leaver, arbitrator, appointed by the PMT JV to be partial, biased against GoI and that he interfered with the witness of GoI during the arbitration hearings and in correspondence with the parties, GoI challenged the mandate of Mr. Peter Leaver in the Permanent Court on Arbitration (PCA). The PCA rejected (June 2013) the challenge brought against Mr. Peter Leaver, QC under Article 10(1) of the UNCITRAL Arbitration Rules. The decision of PCA on Arbitration has been challenged by GoI in Delhi High Court (June 2013).

220. As per Audit, all the afore-mentioned issues are sub-judice as of July 2014.

221. On being asked why ONGC recused itself from the Arbitration and to provide details on its non participation with the other two JV partners BGEPIL and RIL on the matter of arbitration; details of GoI directives to ONGC on arbitration and whether under PSC provisions, unanimous consent of all the JV Partners are required or Parties can separately invoke arbitration against GoI. In response thereto, ONGC has submitted as under:

"The details in this regard are as under:

- In the arbitration between PMT JV and GAIL for non-payment of differential gas price to PMT JVs, MoP&NG vide letter dated 12.06.2007 advised ONGC not to participate in the arbitration and it was also informed by MoP&NG that in case of an arbitral award, same will be applicable to ONGC also, as a constituent of Contractor for both the PSCs.
- Subsequently, MoP&NG, vide letter dated 24.12.2010, advised IOCL & GAIL to allocate the proceeds of petroleum lifted from Panna-Mukta PSC in favour of MoP&NG totaling to USD 80,181,321 of which ONGC's 40% share was USD 32,072,529. The directives of MoP&NG were complied with by IOCL & GAIL.

- M/s BGEPIL informed ONGC vide letter dated 15th December, 2010 that BGEPIL & RIL have served a notice of Arbitration on the Government of India in respect of disputes, differences and claims which have arisen in connection with Panna-Mukta and Mid & South Tapti PSCs.

- Later on , ONGC, vide letter dated 21st April, 2011, informed MoP&NG that prior to serving the notice of arbitration with GoI, the two partners (BGEPIL & RIL) had never informed ONGC, citing earlier communication from MoP&NG dates 12.06.2007 as mentioned above.

- In the above letter dated 21.04.2011, ONGC submitted to MoP&NG that as advised by MoP&NG earlier in case of arbitration proceedings against GAIL, MoP&NG may like to consider that ONGC need not be a party to the current arbitration proceedings and in case of an arbitral award, the same is made applicable to ONGC also, as a constituent of Contractor for both the PSCs.

- In reply ONGC's letter dated 21.04.2011, MoP&NG, vide letter dated 04.07.2011, advised ONGC not to participate in the arbitration initiated by RIL & BGEPIL under Pann-Mukta & Tapti PSCs. However, in case of an arbitral award, the same is made applicable to ONGC also, as a constituent of Contractor for both the PSCs.

  Article 33.2 of Tapti PSC stipulates that "…..any claim arising between the Parties hereunder which cannot be settled amicably may be submitted by **any Party** to arbitration….."

  Hence, the PSC provides the right for arbitration by any Party individually or collectively with other JV Partners".

222. The Ministry during the course of oral evidence have stated as under :

"The attempt of the Government is always to make the ease of doing business on the part of industries and to be away from micro-management. We give more freedom to the operators to operate and we are concerned with the end-result as to how much production he is doing and with the production related whatever Government's stake is there, that should come. He should not be able to do any mischief in that and our attempt is to ensure this.

With this view, as I have mentioned, we have already brought in a new policy where we have moved away from the production-sharing to revenue-sharing contract where we will not look at the day-to-day management like cost recovery and other things. We are only interested as to how much production he is doing; how much revenue he is getting;

> and out of which how much he will share with us. This he has to declare upfront in a formula while bidding and that will be followed.
>
> We will not be entering into their day-to-day operations, so we hope that there will be much less scope for arbitration or court cases or disputes. Even within the disputes also, we always prefer the alternative dispute resolution mechanism instead of we going to the court straightaway. But our experience has been that the arbitrations have also gone ahead for quite longer time. So, I think that we will have to see as to how best we can do."

X. <u>NON-SIGNING OF CRUDE OIL SALES AGREEMENT</u>

223. As per Article 18.1 of Panna-Mukta PSC, each constituent of the Contractor shall be required to offer to the GoI or its nominee all of the Contractor's entitlement to Crude Oil from each Field in order to assist in satisfying the national demand. GoI appointed IOCL as its nominee to purchase entire crude oil produced from the Panna-Mukta field. Further, Article 19.4.4 of the PSC, envisaged formulation of COSA between Panna-Mukta JV and IOCL (GoI nominee) under terms and conditions, normally contained in international COSAs of a similar nature. However, COSA has not been signed (November 2013) due to non-resolution of issues on (i) delivery point, (ii) storage charges, (iii) dead freight, (iv) voyage loss, (v) voyage costs, (vi) terminal charges, (vii) measurement conversion table, (viii) dollar rupee exchange rate, (ix) lay time in monsoon and (x) delayed payments and interest thereon.

224. The non-signing of COSA for Panna-Mukta PSC has been commented by the C&AG in its previous audit reports of 1996, 2005 and 2011 and on each occasion MoPNG stated that *agreements were likely to be finalized soon/suggestions of CAG on COSA would be examined*. However, COSA has not been signed between JV and IOCL till date (November 2013). Thus, due to non-resolution of delivery point and related issues the COSA has not been signed even after a lapse of 19 years of signing of the PSC. The non-signing of COSA led to non- resolution of storage expenses -INR 724.18 crore and voyage expenses-INR 63.56 crore and are shown as recoverable by PMT JV from GoI/GoI’s nominee i.e. IOCL as on 31.3.2012. Further during 1995 to 2007 IOCL deducted dead freight of INR 29.83 crore and voyage losses of US$ 37.03 million which

were also under dispute.

225. PMT JV in its reply to MoPNG (July 2014) stated that *JV has been adhering to the provisions of the Panna-Mukta PSC by selling the crude oil produced from Panna-Mukta to IOCL and that it has also be engaging with the IOCL with the aim of reaching a mutual understanding to enable the signing of COSA.*

226. While MoPNG in its earlier reply stated (February 2014) that*, COSA was not signed between the contractor and IOCL due to continued differences between Contractor and IOCL despite the best efforts made by MoPNG,* in July 2014 it stated that *in the event of any disagreement between Contractor and the oil marketing companies, the Contractor should have resolved the disputes though appropriate dispute resolution mechanism.*

227. According to Audit, since only five years are left for the expiry of the PSC and considering huge impact on IM and GoI PP that may result in case of any change in price, MoPNG may intervene as assured in reply to previous PAs for an early resolution of the disputes and facilitate signing of COSA.

228. The Audit, therefore, recommended that GoI may ensure the signing of COSA between IOCL and PMT JV by expeditiously resolving the contentious issues.

229. Asked to explain on the issue of non signing of COSA the ONGC has submitted as under:

> "The COSA between PMT JV and IOCL has not been signed due to non-resolution of various issues which have commercial implications on the sellers and the buyer. However, as per PSC provisions, the PMT JV has been selling crude oil to IOCL (Government Nominee to offtake crude oil) since inception while at the same making best efforts to resolve the issues and formulate a COSA.
>
> Various correspondences and meetings have been held between PMT JV & IOCL since the commencement of crude oil sales in 1994-95. However, the issues could not be resolved. Subsequently, in 2014 a Task Force was

constituted which has so far held seven meetings, the last one being on 08.03.2016".

230. On the same issue, the Ministry has submitted that:-

"The parties are yet to reach to a final agreement. The delivery point will impact the cost of the buyer and liabilities of the seller of crude oil. Hence there has been disagreement between the buyer and the seller.

**** **** ****

MoP&NG called a meeting on 17th October 2014 to discuss the pending actions emerging from C&AG Audit Report No. 6 of 2005 i.e Para No. 3.3.4(iii) Non finalization of COSA and GSPA and Para No. 3.3.5(i) on Delivery Point tor crude oil. After detailed deliberation, the following was decided:

(i) Next meeting of JV partners and IOC to be held on 31st October, 2014 and the minutes of the meeting to be submitted to the Ministry by 2nd November, 2014.
(ii) Minutes of the meeting held on 23.04.2014 to be submitted to Ministry before next meeting scheduled on 31.10.2014.
(iii) All issues to be settled amicable by 30th November, 2014.

As on date six meetings of Task force were held on 23.04.2014, 31.10.2014 & 14.11.2014, 29.01.2015 , 20.04.2015 and 8.03.2016 to discuss issues related to crude oil sales contract for crude from Panna-Mukta contract area.

As per the Minutes of the meeting of 5th Task Force held on 20 April 2015 on the settlement of issue related to sale of crude oil for Panna – Mukta have agreed on the delivery point, storage vessel costs, measurement method, voyage loss deductions, other fair weather voyage related deductions, other monsoon voyage related deductions, other voyage related deductions, settlement between parties in relation to crude sale and purchase and interest. It was also agreed that the PMT-JV shall prepare a draft settlement agreement on the basis of these signed minutes within 15 days. The PMT JV will share a draft of the more detailed COSA within 90 days from the date of execution of the Settlement Agreement.

The Parties have agreed that post signing of the settlement agreement and until such time that the COSA is executed, the settlement agreement shall be binding agreement between the Parties and which shall be basis on which all future sale and purchase of crude oil from Panna-Mukta area occurs.

Final agreement between the parties has to be arrived based on the discussions amongst them."

XI. COST RECOVERY OF UNCONSUMED PRODUCTION INVENTORY

231. As per section 3.1.8(a) of AP of the PSC, the material and equipment held in inventory shall be charged to the accounts only when such material is removed from inventory and used in Petroleum Operations. *Contractor is allowed to recover interest at the LIBOR rate plus one per cent (1%) for reasonable inventories it carries. Costs shall be charged to the accounting records and books based on the average cost method'*.

232. However, contrary to the PSC provision, Contractor charges production inventory to cost recovery on date of purchase irrespective of its actual usage in Petroleum Operations. As on 31 March 2012, PMT JV was holding production inventory worth US$ 26.15 million (accumulated since Pre-SAP, i.e. before April 2005 – US$ 4.84 million) which was charged to cost recovery.

233. Out of total inventory of US$ 26.15 million as on 31 March 2012, inventory valuing US$ 11.03 million was not used for more than four years. The cost recovery of production inventory without its actual usage for petroleum operations had adversely impacted GoI share of PP.

234. Contractor needs to reverse production inventory charged from the respective FYs by recovering inventory carrying cost on reasonable inventory under section 3.1.8 (a) of Accounting Procedure to the PSC from date of purchase till its actual consumption for Petroleum Operations and remit the additional PP to the GoI along with interest @ LIBOR plus one (1) *per cent* as provided under section 1.7.3 of Accounting Procedure to the PSC.

235. PMT JV in its reply to Audit (February 2014) and to MoPNG (July 2014) stated:

> *1. "Only controllable assets used for or in connection with Petroleum Operations such as drilling tangibles are inventory (see section 4.2.1(a) of Appendix C). In contrast, the items referred to by the CAG are small value items in the nature of consumables (i.e. chemicals, spare valves, maintenance spares required for various offshore equipment, nuts and bolts, etc.) used for operations and maintenance. Ever since inception, the PMTJV's accounting policy has been to charge the costs incurred in respect of these*

consumable items to the accounts as Production Costs and cost recover them on purchase rather than on consumption. Accordingly, the PMTJV has not recovered any inventory carrying cost on these items.

2. *The PMTJV has endeavoured to ensure that such production consumable items are maintained at reasonable levels so as to avoid any production downtime due to non-availability of such items. An increase in project activities since 2005 resulted in a corresponding increase in consumable items of relevant specifications. The award of contracts to L1 bidders results in spares being purchased from different manufacturers. As a result, separate spares are often required for each make of equipment, which increases the number of spares being stored for ready use".*

236. The reply to Audit was not acceptable in view of the following:

(i) The PSC provides that inventory should be cost recovered as and when actually consumed and the cost recovery of the inventory on purchase is not correct.

(ii) Section 3.1.8 (a) of Appendix C of PSC did not differentiate material as consumable or small value items and reiterates that material or equipment held in inventory shall be charged only when used for petroleum operations.

(iii) The other PSCs, *viz*. KG-DWN-98/3 and Ravva, also provided for charging of inventory on use for petroleum operations.

237. MoPNG, in its reply (February/July 2014) agreed that *inventory not consumed should not form part of contract cost and is not allowed for cost recovery. The issue was raised by M/s Sharp & Tannon for the years 2005-06 and 2006-07 which was duly addressed in the revised computation of the auditor and agreed to remedy appropriately for subsequent years. Year wise inventory included by Operator in the Contract Cost if provided by Audit would be corrected in the account for subsequent years also.*

238. The PMT JV furnished the year-wise production inventory for the years 2008-12 while the data for the years 2006-08 though sought was not furnished by the Operator during last round of audit and, hence, the inventory movement for the year 2008-09 could not be worked out. The year-wise production inventory movement (as desired by the MoPNG) in respect of Panna-Mukta and Tapti Contract Area for the years 2009 to 2012 are tabulated below.

(in US$ million)

Year	Inventory Movement	
	Panna-Mukta	Tapti
2009-10	2.64	1.59
2010-11	3.92	0.52
2011-12	1.49	1.22

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

240. When asked whether PMT JV has now ensured that production inventory is charged to accounts only when material is removed from Inventory and used in petroleumoperations as provided in the PSC, the Operator replied as under :-

> **"** PMT JV maintains that it has been following the practices since inception in line with the Accounting Procedure of the PSC. Further, the items referred to by the CAG are small value items in the nature of consumables used for operation and maintenance. The PMT JVs accounting policy has been to charge the cost incurred in respect of these consumables as Production Costs and cost recover them on purchase rather than on consumption. Accordingly, the PMT JV has not recovered any inventory carrying cost on them. The JV has not agreed to this audit exception.
>
> The Government's view has been that as per Generally Accepted Accounting Principles, expenditure recognition can be done only when inventory is consumed. There is no Accounting Procedure of the PSC suggesting that the inventory can be accounted as Contract Cost even before it is consumed."

241. The Ministry in their Action Taken Note have stated that "the Contractor's contention is not in accordance with Accounting principles and is not acceptable. As suggested by C&AG, the inventory will be reduced from contract cost and GoI share of profit petroleum will be recomputed".

XII. <u>AWARD OF CONTRACT FOR INSTALLATION OF PLATFORMS</u>

242. Following abandonment of SWP project (as discussed in para 3.6.4.1), PMT JV decided to shift its facilities to the PL location. PMT JV entered into a settlement agreement with M/s Swiber (the existing contractor for installation of PK and SWP

platforms) for relocating these facilities on a nomination basis in March 2010. It was noticed that the actual cost for transportation and installation far exceeded the estimates.

243. The cost estimate prepared in August 2008 had indicated the total cost at US$ 15.8 million (including US$ 6.0 million for mobilization and de mobilization). Against this, the actual contracted price was more than double at US$ 35.98 million (including US$ 29 million for installation and US$ 6.98 million for transportation). Besides, the award was made on a settlement basis with M/s Swiber rather than a tender as mandated in the PSC.

244. PMT JV in its reply to Audit (February 2014) and to MoPNG (July 2014) stated that

- *The cost for transportation and installation as US$ 9.8 million is incorrect. This estimate comes from the PL POD which was merely an early estimate of the likely cost.*
- *PMTJV engaged Swiber to undertake the modifications to minimize the time for award of contract as the material was under care of Swiber; there was concern that there might be a dispute under the existing contract with Swiber regarding incomplete scope and there was no desire to incur extensive storage costs from Swiber.*
- *US$ 26.5 million would have been incurred had the PL installation been undertaken using the variation rates of the SWP-PK contract and the actual utilisation.*
- *The contract price of US$ 29 million is reasonable compared to US$ 26.5 million agreed for the installation of the SWP and PK platforms and pipeline under a prior contract.*

245. The reply was not acceptable to the Audit, since the estimates for PL platform had been prepared in August 2008 based on the quotes received in the tender for SWP and PK platform. The contract for SWP-PK was awarded in September 2008 to Swiber whose quotes were L1. The total installation cost of US$ 26.5 million was for two platforms (SWP and PK) and two pipelines hence is not comparable to US$ 29 million for the single PL platform and pipeline. The costs incurred for the transportation and installation of PL was, thus, comparatively very high.

246. MoPNG in its reply stated (July 2014) that *the audit exception has been notified to the Contractor. The CAG may recommend in its final report the amount to be disallowed from the Contract Costs after considering Contractors' reply, if any.* The non-adherence to the prescribed tendering procedure has been commented by Audit. The contract was awarded without competition and the rates are seen to be high on comparison with similar works. As there was no price discovery, Audit is unable to quantify the impact in the instant case.

247. The Ministry in Action Taken Note has submitted that "as stated, Audit is unable to quantify any impact in the instant case. The transaction with M/s Swiber not being termed as an affiliated transaction causing any undue benefit to the contractor".

XIII. PETROLEUM OPERATIONS

A. Delay in Water Injection (WI) project in Panna field resulting in declining production

248. Oil production from a field undergoes three phases: primary, secondary and tertiary. Primary oil recovery is limited to hydrocarbons that naturally rise to the surface. With the passage of time and continuous production of oil reserve, the natural reservoir pressure gets depleted and secondary recovery methods like water and gas injection are employed for displacing the oil and driving it to the surface.

249. The reservoir pressure of Panna field which was 2550 psia[18] at the beginning (1986) gradually started falling. Consequently, the production from Panna field started declining. The declining rate which was 10-12 *per cent* in 2003 increased to 12-15 *per cent* in 2007-08, and to 18-20 per cent in 2010-11.

250. Both DGH as well as the JV in 2003 itself was aware of the declining production.

[18] *pounds per square inch absolute.*

Though the JV carried out a feasibility study for water injection[19] in Panna at that time, the low prevailing oil prices (US$ 18-20/bbl) rendered the project uneconomical. The crude oil price subsequently increased from an average of US$ 27.69 per barrel (2003) to US$ 50.00 per barrel (2005) and to US$ 64.2 per barrel (2007). The JV, however, did not review the feasibility for water injection. By 2007, the reservoir pressure had further declined to about 2000 psia. On the direction (February 2007) of DGH, the JV conducted studies in 2007-08 and 2008-09 and found water injection to be technically feasible. The returns were, however, expected to accrue only after 4-5 years from start date. Since the PSC term was to expire in 2019, the JV desired for extension of the PSC term. In 2008-09 DGH had also agreed for request of PSC term by the JV and in the MC meeting held on 20 January 2009, DGH asked the JV to submit an outline of water injection proposal together with request for PSC extension. The JV, in February 2009, informed DGH that it had prepared a detailed report on feasibility of water injection but submitted the feasibility report to DGH only in September 2011. It also made a request for extension of PSC term.

251. DGH is yet to approve the feasibility report. DGH, however, wrote (March 2012) to JV stating that '*pressure maintenance should have been started as soon as it was evident that the reservoir pressure was falling below saturation point'* and that the Operators *'should have proposed WI in early 2000 if they were serious about good operational standards and reservoir management*'. As on date there is no further progress in the WI scheme pending approval of pre feasibility study and decision on the PSC extension by DGH.

252. Audit observed that PMTJV and DGH recognized that delays would result in irreversible loss of oil recovery. Each year of delay was expected to result in loss of reserves of 4-5 mmbbl. As per the JV's letter of April 2012 to DGH 'any delay was expected to have an exponential and detrimental impact on its overall technical and economic viability due to pressure drop and watering out of the existing wells'.

[19] *Water injection involves drilling injection wells and introducing water into the reservoir to encourage oil production. While the injected water helps to increase depleted pressure within the reservoir, it also helps to move the oil in place.*

253. The protracted delay in submission and correspondence was, however, not followed by any action. With each year of delay the voidage would increase resulting in need for more facilities and higher cost impacting project viability. Though DGH was aware of the need for implementing the WI at the earliest as a technical requirement for enhancing the recovery of production, they failed to expedite the same mainly due to indecision on the extension of PSC term. Meanwhile, the reservoir health deteriorated.

254. PMT JV in its reply to Audit (February 2014) and to MoPNG (July 2014) stated that

(i) *"PMT JV had sought an alternative method to optimize production level at Panna namely through drilling of development wells and active reservoir management. As stated in an Operating Committee resolution dated 7 April 2003 'infill drilling in Panna along with a gradual relaxation of field gas rate is a robust reservoir management and field development strategy for a coning dominated reservoir like Panna B zone, both from a technical and economic view point.*

(ii) *PMT JV did not reconsider the decision to opt for infill drilling rather than water injection when oil prices began to rise as the infill drilling and EPOD work proved to be a robust reservoir management and field development strategy.*

(iii) *The technical risks of water injection when compared to its relatively low economic value both for the PMT JV and the GoI, have deterred the PMT JV from performing this work. PMT JV had identified water injection as a marginal project as the potential incremental increase in production does not appear to justify the high upfront capital costs of US$ 2.2 billion required for water injection...' '... and that the project was not economically viable within the current PSC period and was only marginally economically viable even if an extension were granted.*

(iv) *Early breakthrough of injected water reducing the anticipated hydrocarbon recovery has already been seen in a tracer study. Implementation of water injection scheme in earlier years carried the risk of causing an uneven movement of hydrocarbons in and lower ultimate recovery from Panna reservoir, where a thin oil column enclosed between large gas cap and an aquifer is very sensitive to water to any such water injection scheme.*

(v) *The PMT JV has diligently properly and efficiently developed the oil and gas fields underlying the Panna-Mukta and Tapti PSC contract areas in accordance with the PSC terms and best international practices and standards".*

255. MoPNG in reply stated (July 2014) *that declining of production has always been explicitly known whereas all geological phenomena may not have technical solutions, as cost factor will also be a matter of significance.*

256. DGH raised (January, March and April 2012) the following issues: *a) the proposal included water injection scheme for B-zone and did not include water injection for A-zone; b) many technical queries to JV remain unanswered. In a MCM held on Jan. 04 2013, the JV informed that they would be reevaluating the water injection project feasibility in view of recent geological surprises (quick recovery of tracer within two days from wells 2-3 kms apart after water dumping) in Panna field.*

The PMT JV is yet to submit the modified water injection pre-feasibility reports for both Panna-B and A zones incorporating the present geological observation and find out a techno-economically viable project. The technical issue before the JV is to find out a techno-economically viable project to enhance the recovery. Arresting the rate of fall in reservoir pressure will be one of the favourable technical outcomes expected from a water injection project.

257. According to Audit, the replies need to be viewed in light of the following:

- The reservoir pressure continued to fall and production decline increased from 10-12 *per cent* in 2003 to 12-15 *per cent* in 2007-08 and to 18-20 *per cent* in 2010-11. As per the JV the decline in production due to pressure depletion in 2011 alone was estimated at about 2 mmbbls of oil. Also 40 *per cent* of wells in Panna were closed due to increase in water cut.
- DGH from time to time (January 2009, March 2010, November 2010 and August 2011) had directed PMT JV to implement the WI in Panna field at the earliest to resolve the reservoir health and to control the decline in pressure. DGH in March 2010 had stated specifically that 'until WI started no infill wells were likely to be considered'. DGH however, continued approval of infill wells in 2011-12.
- In the various technical committee meetings/workshops conducted during March 2010 and October 2011) while the JV acknowledged

that '*studies over the past few years had provided a better understanding of the field which now allowed WI project to be implemented effectively and that WI scheme was appropriate for implementation and reasonable*', DGH observed '*Technical studies of WI had reached substantial maturity for it to be implemented now. Model refinement and project optimization would continue but in parallel with WI project implementation'*. DGH strongly advised to schedule all activities targeting start of WI from early 2014.

- Besides, the technical scheme, incremental reserves and facilities cost for the B zone water injection project were also reviewed and endorsed by independent Auditors viz. Worley Parsons and Reservoir Knowledge in October-November 2010.
- The Pre-Feasibility report submitted in September 2011 had also brought out that '*the project risks with regard to Reservoir uncertainties around reservoir heterogeneity, residual oil saturation, movement of oil into gas cap, injectivity, water injection compatibility with reservoir, etc. would always exist as part of nature and would be addressed on a regular basis as part of ongoing reservoir characteristics*.' Most of the risks were stated to be contained and factored in the current analysis as part of model calibration process.
- The PMT JV while submitting the Pre Feasibility study report brought out that expeditious implementation of Water injection scheme as envisaged could yield 6% incremental gain (71.6 million stock barrels oil and 94.9 bcf gas upto economic life of 2038).
- DGH took six months (October 2011 to March 2012) to review the report and communicated its comments to the JV in piecemeal even though it had actively participated in the technical committee meetings/workshops and had also directed the JV on the studies to be conducted.
- Considering that the water injection study is yet to be approved and a decision on PSC term is yet to be taken and with delay having adverse impact on the recovery factor, it is unlikely that the WI scheme would be implemented in near future.

258. As per Audit, the loss in production during 2008-09 to 2011-12 was to the extent of 77282848 bbls of oil valuing US$ 661.86 million.

259. The Ministry in Action Taken Replies has stated that " DGH attempted time again to bring in a secondary recovery project to enhance the petroleum recovery that would also be commercially viable to all parties. The quantum of incremental recoverable reserves is a complex technical issue beyond the comprehension of an audit exercise,

and depends on various factors such as technology availability and its application, cost structure of the Operator, contractual provisions, technoeconomic risk factors etc. The PMP JV had submitted a 'Panna B Zone Water Injection Pre-Feasibility Report' in 2011 and subsequently a request for PSC extension till filed economic life. The proposal however was not found to be commercially viable. In the MCM held on January 04, 2013, the JV informed of more geological surprises of water dumping in Panna field. A techno-economically viable project could not be identified to enhance the petroleum recovery.

Audit's loss computation represents the audit's computed value of petroleum not lifted from the reservior. Theoretically only a fraction of the in place oil gets recovered over the field life (about 16% in Panna). As technology improves resulting in new cost effective methods, more and more secondary recovery methods would be applied to increase the petroleum recovery. The new enhanced project also is required to be evaluated in the light of CAG's audit report no. 19 of 2011 discouraging that leads to reduction in Government Take."

XIV. SALE OF GAS BY ONGC AND TWO JV PARTNERS (RIL AND BGEPIL) IN CONTRAVENTION TO MOPNG'S DIRECTIVES.

260. As per the terms of the PSCs, Panna-Mukta reached the revised ceiling price of US$ 5.73 / mmbtu in February 2005 and Tapti contract area reached US$ 5.57 / mmbtu in June 2004. However, GAIL, which was nominated by MoPNG to purchase the entire gas production, refused to honour the revised gas prices , and continued to pay the gas price at the earlier ceiling of $ 3.11 / mmbtu till March 2005. Consequently, MoPNG instructed (November 2004) PMT JV to supply 6 mmscmd (out of the total gas production of 10.8 mmscmd) to GAIL at $ 3.86 / mmbtu for one year, and allowed PMT JV to market the balance gas (4.8 mmscmd) directly at a price higher than $ 3.11 / mmbtu or such price as may be offered by GAIL. The JV entered into contracts with private customers for the remaining 4.8 mmscmd at $ 3.96 / mmbtu for a three year period upto March 2008. In view of criticality of supply of PMT gas to the priority sector, GoI reviewed its earlier decision. At the request (March 2006) of GoI, PMT JV supplied 5 mmscmd of gas to GAIL for the period from 1.4.2006 to 31.3.2008 at a market driven

price of US$ 4.75 / mmbtu. The additional gas in excess of 10.8 mmscmd produced by PMT JV was shared by the JV partners according to their PI and they entered into separate contracts at different prices ranging from US$ 4.60 per mmbtu to US$ 5.58 per mmbtu. MoPNG in October/November 2007 reviewed the PMT JV gas supplies and directed PMT JV to sell entire quantity of PMT JV gas to GAIL at revised PSC price with effect from April 2008.

261. In the previous Audit Report No. 19 of 2011-12, Audit had commented vide para 6.3.1 on the sale of entire JV gas during 2005-2008 at different prices to different parties. Audit concluded that the pre-determined PSC pricing formula has not been adhered to which severally affects the sanctity of the contract. This was highly undesirable from the long term perspective of all contracting parties. In the present report, Audit has discussed the issues regarding sale of additional production of gas (over and above 10.8 mmscmd of gas) from the additional production of PMTJV in contravention to MoPNG directives and GSPA and are discussed.

262. The Ministry in Action Taken Reply have stated that " the factual position was under the two PSCs, gas was required to be sold to GAIL only. The gas price was to be determined between GAIL and the JV sellers in accordance with a formula stipulated in PSC. In view of the sudden jump in gas price payable by GAIL in 2004-05 consequent to the structure of pricing formula, dispute arose between GAIL and JV on gas price. At the meeting of the Secretary on 22 April 2004, it was decided that the JV should amicably negotiate the price of Gas with GAIL as GAIL showed inability to purchase at rate more than US $ 3/mmbtu. On 28.06.2004, the PMT JV wrote to GAIL that th erevised price of gas to be US $ 5.57/mmbtu as per the formula provided in the PSC. On 25.10.2004, PMT JV wrote to MoPNG to intervene directly in response to GAIL inability to pay more than the US$3.11. At the meeting with the Secretary, MoPNG on 29.03.2005, it was decided that PMT JV will directly market gas w.e.f. 01.04.2005 and that GAIL would pay a price of US$3.86 and the same would be applicable for sale of gas to other customers".

A. Loss of US$ 9.92 million due to sale of gas in contravention to MoPNG directives and GSPA

263. (A) GoI had decided (March 2006) that a separate meeting would take place at an appropriate time for dispensation of additional gas production (over and above 10.8 mmscmd).

264. However, contrary to the GoI decision, ONGC (JV partner) entered into a long term contract for 12 years and signed GSPA in June 2006 with TPL for supply of 0.9 mmscmd of gas @ US$ 4.75 / mmbtu from its share of gas from PMT JV. BGEPIL and RIL (other JV partners) also sold their share of additional gas from Phase-II development plan to its affiliates and GSPC. Though this was contrary to GoI decision, the sale price of BGEPIL and RIL was US$ 5.58/ mmbtu (i.e. higher by US$ 0.01 per mmbtu of revised ceiling price of Tapti field). As per contract entered with TPL, ONGC agreed to supply its share of gas of 0.90 mmscmd for a period of 12 years with a provision to review the price after expiry of 3 years from the date of first supply. ONGC also informed (December 2007) MoPNG that the contract with TPL was signed after following a tendering process and therefore, the contract should be honored by MoPNG / GAIL. Subsequently, MoPNG intimated (March 2008) ONGC that the contract entered with TPL would be assigned to GAIL. Supply to TPL commenced from 30 May 2008 and continued at the lower rate of US$ 4.75 per mmbtu till May 2011. Supply to TPL was made at PSC price only from June 2011.

265. The agreement for sale of gas entered in June 2006 to TPL was in contravention to MoPNG’s direction of March 2006.

266. BGEPIL and RIL not being parties to the contract between ONGC and TPL, PMT JV forwarded (January 2014/July 2014) the response of ONGC. ONGC invited attention to MoPNG letter dated 31 March 2008 on supply of gas from PMT fields to TPL which envisaged that the Price would be reviewed, as due under the contract and the then prevalent PSC price shall be applicable from the date of such review. As per the contract Daily Committed Quantity (DCQ) and Sales Gas Price were valid for a

minimum period of three years. The supply to TPL commenced from 30 May 2008, and its revisions as per terms and conditions of the contract/contractual commitments was applicable after May 2011. Accordingly, the PSC price was adopted for supply to TPL from June 2011 onwards. In view of the above it cannot be said that sale of gas to TPL by ONGC is in contravention of MoPNG directives.

267. Reply was not acceptable to the Audit. ONGC ignored MoPNG directives of March 2006 which had categorically stated that a separate meeting would take place at appropriate time regarding dispensation of additional production of gas and signed the GSPA with TPL in June 2006 for sale of its share of gas below the PSC price i.e. @ US$ 4.75 per MMTBU. Though the other two partners also ignored MoPNG directives, their share of additional gas was sold at US$ 5.58 per mmbtu, i.e. higher by US$ 0.01 per mmbtu of Tapti PSC ceiling price. MoPNG also expressed (November 2007) its displeasure for non-adherence to its directives and directed PMT JV to sell entire production to GAIL at PSC price with effect from April 2008 onwards. MoPNG had to honour the contract of ONGC with TPL (March 2008) as the contract has already been concluded. This led to loss of revenue of US$ 19.62 million to PMT JV (ONGC). This also adversely impacted GoI Take in form of PP, royalty and income tax by US$ 9.92 million.

268. MoPNG in its reply stated (July 2014) that neither this report of the CAG nor the earlier report No. 19 of 2011 adversely commented on the PMTJV's supply of gas at prices lower than PSC price during period 2005 to 2008. In view of the CAG's adverse comment on ONGC's supply of gas to TPL at US$ 4.75 per mmbtu after 2008, it may to be appropriate to relook at the price charged by PMTJV for direct sale of gas (which has not been reported by CAG as having been sold through tendering process unlike in the case of ONGC) at prices less than price prior to 2008. This issue may be deliberated in the final report so that a uniform consistent stand is taken in respect of the different prices charged by the Contractors. In the previous Audit report for the year 2011-12, CAG commented adversely on GAIL's refusal to buy gas at PSC price but failed to express its views on direct sale by PMT JV at less than PSC price.

269. CAG may be aware that the two Companies in PMTJV invoked arbitration against GAIL on the pricing issue and reached at a final settlement of partial enhancement of the price paid by GAIL. CAG may look at the appropriateness of enhancement of the price which was paid by the 'direct' buyers in line with the enhancement of price obtained from GAIL. As the customers of 'direct' sale happen to be either the Companies themselves or their affiliate, reopening the pricing of gas should not pose any commercial complication.

270. MoPNG also stated that one of the issues flagged by CAG is that the Contractor paid less income tax due to charging a price less than PSC price. This would be notified to the Income Tax Department for taking final view after audit issues its final report taking into consideration the reply of the contractor.

271. As the PSC stipulates GAIL as the buyer of gas and provides specific terms and conditions on the pricing formula to be adopted by the buyer of gas, MOP&NG communications may not be construed as amendment to such PSC provisions.

272. MOP&NG's communications referred by CAG are the fallout of a situation where as per PSC the PSU nominee GAIL was required to pay a higher price but failed to pay the higher price in the circumstances of GAIL's requirement to subsidize the gas price. Considering CAG's admission that the pricing by ONGC was through a tendering process, the issue before the CAG for consideration for final recommendation is whether any better option existed in the circumstances.

273. The response of MoPNG may be viewed in context of the following:

(i) The Audit Report no. 19 of 2011-12 had pointed out the non-adherence to PSC price which affected the sanctity of the contract (which is to be maintained by all parties). The differential prices at which 10.8 mmscmd of gas was sold by PMTJV to GAIL vis-à-vis its affiliates and GSPC during 2005-08 had also been elaborated in the report (para 6.3.1). The present observation is regarding sale of additional 5.7 mmscmd of gas by the partners, the concern being sale of gas by ONGC at prices lower than the PSC price.

(ii) The PSC price had not been honored and hence the need for MoPNG intervention. Audit has commented on the non-adherence of all partners to MoPNG direction for sale of additional gas and its impact.

(iii) While it is not disputed that ONGC went through a tendering process, the point being made is that ONGC was not authorized to do so by MoPNG and that the price at which the transaction was concluded was much lower than the PSC price.

(iv) The other partners, RIL and BGEPL derived the PSC price through sale of their share of the gas at the same time. This points to existence of better option to ONGC.

274. Audit further observed that, GoI also directed that supply be incumbent on present level of production of PMT fields and in the event of decrease in the same, there would be a pro rata reduction in supplies to all customers, including TPL. Article VIII of tripartite agreement also stated that the parties agree that the supply of Gas to TPL under the Clause 2.3 of the Existing Contract shall be incumbent on present level of production from PMT fields (i.e. 17.3 mmscmd), as provided under Gas Supply Contract between GAIL and PMTJV and in the event of decline of the same, there would be pro rata reduction in supply to TPL in accordance with the Annexure 12. Accordingly, the quantity review envisaged every three years under clause 2.1.b of the Existing Contract or stated elsewhere in the Existing Contract, shall not be applicable.

275. Though there was substantial drop in production in the Tapti and Panna-Mukta fields during the year 2008-09 to 2011-12, supply to TPL was not reduced proportionately by ONGC. On the contrary, ONGC sold more gas to TPL during 2009-10 to 2010-11vis-à-vis 2008-09. This resulted in a revenue loss (net of GoI-PP and Royalty) to ONGC by US$ 4.17 million (which is included in revenue loss of US$ 19.62 million).

276. BGEPIL and RIL not being parties to the contract between ONGC and TPL, PMT JV forwarded (January 2014/July 2014) the response of ONGC. ONGC argued that "Article VIII of Tripartite Agreement was not applicable to ONGC. As per tripartite agreement, GAIL shall be fully responsible for the performance of the existing contract, including supply of gas, adhering to the terms and condition and ONGC shall have no

obligations, liabilities whatsoever arising out of the same contract".

277. To Audit, the reply of ONGC is not convincing. As ONGC was selling its share of gas to TPL below the PSC price, it was obligatory on the part of ONGC to periodically inform GAIL about drop in level of production for making proportionate reduction in supply to TPL in accordance with Article VIII of Tripartite Agreement, so as to protect its financial interest. ONGC's failure on this account benefited the private party, i.e. TPL resulting in a loss of revenue of US$ 4.17 million to itself and adversely impacting GoI take by US$ 1.47 million.

278. MoPNG in its reply (July 2014) stated that the audit exception has been notified to ONGC and CAG may like to consider ONGC's response. Specifically it needs to be seen whether GAIL could have reduced the supply to TPL by virtue of the provisions quoted by Audit, in the light of the fact that gas was actually available for supply to TPL at the entire agreed quantity.

279. As already brought out in para Article VIII of tripartite agreement provided for pro rata reduction in supply to TPL in the event of decline in gas production. As ONGC suffered a loss in sale of excess gas to TPL, it ought to have protected its interests appropriately.

280. The Ministry in Action Taken Reply have stated that " the categorisation of a part of gas produced from the two fields as 'additional gas' is not appropriate. The entire gas was entitled to be priced based on PSC formula. Selling of gas at prices other than that based on PSC formula by all the constituents of contractor impacted profit petroleum and royalty. It is a matter of fact that due to the disturbance caused by GAIL's inability to lift gas at a higher PSC formula based price, the private companies started billing part of the gas at US $3.96 and part of the gas at US $ 5.58 to their affiliates. Gail itself was lifting at gas prices of US $ 3.86 and 4.75. On the other hand as noted by CAG, ONGC invited tender and entered into agreement in June 2006 with TPL for supplying gas at a comparably higher price of US $4.75. As explained above, the notional revenue loss was on account of the fact that the PSC formula based price was above the prevailing

market price and in the absence of GAIL uplifting the entire gas quantity, the constituents of Contractor were allowed to sell gas at rates ranging from US $ 3.86 to US $ 5.58 ONGC's sale to TPL, being a price discovered through tendering stood on a better ground than other case. This issue arose mainly due to the fact that the PSC formula based gas price happened to be much higher than the price paid by GAIL till then. Currently the entire gas is lifted by GAIL at PSC formula based price".

B. Loss of government revenue of US$ 0.52 million due to sale of Panna-Mukta gas in contravention to PSC

281. While ONGC sold its share of additional 5.7 mmscmd of gas at US$ 4.75 per mmbtu, the other two partners (RIL and BGEPIL) sold their share of additional gas from both Panna Mukta and Tapti fields at US$ 5.58 per mmbtu. Audit noticed that 14,767,436 mmbtu of gas sold was from Panna-Mukta field which was sold to private consumers at US$ 5.58 per mmbtu, the price being lower than the Panna Mukta PSC ceiling price of US$ 5.73 / mmbtu. This resulted in loss of revenue of US$ 2.22 million and resultantly loss of revenue to the GoI of US$ 0.52 million in the form of PP and royalty.

282. While stating that the issue relates to pre date period being audited by C&AG and hence outside the scope PMT JV in its reply to Audit (January 2014) and to MoPNG (July 2014) stated that GoI had permitted PMTJV to market the surplus production of gas directly to consumers during {the Direct Gas Marketing (DGM) period)}. Accordingly, the gas price stipulated in the PSCs was not applicable during the DGM period. The gas price paid by GAIL and other buyers during the DGM period was a market driven price which was established on an arm's length basis with non-affiliated parties such as GSPC. As such, any loss in revenue to the GoI during the DGM period arose from the failure of GAIL and the GoI to comply with their respective obligations and not any failure on the part of the PMTJV. Upon the Government revoking its direction to the PMTJV to market gas directly, the gas price reverted to the PSC price with effect from 1 April 2008. The additional gas was allocated predominately from the Tapti field. Only a very minor proportion was supplied from Panna-Mukta (circa 1 % of sales) between December 2006 and September 2007 to maintain contractual

commitments. From October 2007, additional volumes of gas from Panna-Mukta were supplied under the existing contracts which offered the highest price i.e. US$ 5.58/mmbtu.

283. To Audit, reply of PMT JV is not convincing. The market driven gas price paid by GAIL and other buyers during DGM period was for sale of 10.8 mmscmd of gas. In addition to this, PMT JV produced approximately 5.7 mmscmd of gas during the period 2006-08 both from Panna-Mukta and Tapti contract areas. PMT JV partners contracted their share of additional quantity to private customers, mostly its affiliated parties at different prices. BGEPIL and RIL sold their share of gas @US$ 5.58 / mmbtu. During last round of audit (2006-08), in response to audit query, PMT JV stated that this additional gas production of 5.7 mmscmd (16.5 less 10.8 from Phase-I existing surface facilities) came from the Phase-II development of new surface facilities of the Tapti Contract area which was sold at a price of US$ 5.58 per mmbtu i.e. US$ 0.01 / mmbtu higher than the revised Tapti ceiling price. Hence, there was no loss to the GoI in any form. However, Audit in the follow up audit of 2008-12, verified the reply of PMT JV to the Audit Exception notified by MoPNG for 2006-08 and found discrepancy and hence the argument of PMT JV that the issue falls outside of scope of audit is not tenable. Audit observed that PMT JV also produced additional gas (14,767,436 mmbtu) from Panna-Mukta field for which gas price of US$ 5.73/ mmbtu was applicable. Sale of Panna-Mukta gas at Tapti gas price led to loss of GoI PP and royalty of US$ 0.52 million that needs to be paid to GoI along with applicable interest. The contention of PMT JV that only a minor proportion was supplied from Panna-Mukta was not acceptable since there were different PSC prices for Panna-Mukta and Tapti gas and the quantum did not have any bearing as contested by PMT JV.

284. MoPNG in its reply (June 2014) stated that notwithstanding the Contractor's reservation that the audit query relates to pre-date period being audited, CAG may like to give the financial impact of the two companies charging a price less than the PSC price for gas supplied to their affiliates during the entire period including for the years prior to period of audit. CAG may suggest the course of action that is available for MOP&NG, if any, as a remedial measure.

285. The financial impact of GoI take (Royalty and GoI PP) due to sale of gas below PSC price by PMTJV and its partners over the period 2005-08 was US$ 107.66 million (Annexure 12). The financial impact for 2008-11 arising from sale of gas by ONGC to TPL at a price lower than PSC price has been worked out at para 3.6.3.2.5 above. GoI may take an appropriate view of short payment of GoI PP and royalty on this account under PSC provisions.

286. The Ministry in its response has stated that :-

> "It is a matter of fact that due to the disturbance caused by GAIL's inability to lift gas at a higher PSC formula based price, the private companies started billing part of the gas at US$3.96 and part of the gas at US $ 5.58 to their affiliates. GAIL itself was lifting at gas prices of US$3.86 and 4.75. On the other hand as noted by C&AG, ONGC invited tender and entered into agreement in June 2006 with TPL for supplying gas at a comparably higher price of US$4.75.
>
> As explained above, the notional revenue loss was on account of the fact that the PSC formula based price was above the prevailing market price and in the absence of GAIL uplifting the entire gas quantity, the constituents of Contractor were allowed to sell gas at rates ranging from US$ 3.86 to US $5.58. ONGC's sale to TPL, being a price discovered through tendering, stood on a better ground than other case. As recommended by CAG, MoPNG will take a final view after considering the response of the contractor."

287. The Ministry in their Action Taken Reply have stated that " In the draft audit report, CAG observed that ONGC's sale of gas to TPL was at a price less than PSC formula price. In the final report CAG has computed that the price difference between the PSC formula price and actual price charged by JV during the years 2005-06 to 2007-08 worked out to US $ 234 million in Panna Mukta and US $ 252 million in Tapti (Annexure 12 of CAG report) causing loss of US $ 107.66 million in Royalty and GOI share of Profit Petroleum. CAG has also computed a revenue loss of US$ 19.62 million in respect of gas supplied to TPL by ONGC during 2008 to 2011. As recommended by CAG, MoP&NG will take a final view after considering the response of the contractors".

288. On being asked what were the views on the observation of the Audit that the PMT JV partners contracted their share of additional quantity of gas to private

customers, mainly their affiliates at different prices which led to loss of GoI Profit Petroleum and royalty of US $0.52 million needs to be paid to GoI along with applicable interest. ONGC replied as under:

> "During the year 2004-05, GAIL (Government Nominee for purchasing the entire JV gas) expressed inability to honour the revised PSC price. As a result, for a period of three years (2005-2008), GAIL purchased only a portion of gas from the fields and at a price lower than what is stipulated in the PSCs, and GoI permitted the PMT JV to market the surplus gas directly to consumers for which the gas price stipulated in the PSC was not applicable. The additional gas was mainly allocated from Tapti field with a very minor portion from Panna-Mukta field. It may also be noted that from October 2007, additional volumes of gas from Panna-Mukta were supplied under the existing contracts which offered the highest price of US$ 5.58/mmbtu.
>
> However, Government may not agree with the Contractor's view that the gas price stipulated in the PSC is not applicable to the gas sold to affiliated parties as the direct sales to affiliated parties arose for the reason that PSC price was not paid by GAIL"

XV. DELAY IN NON-FIXATION OF TRANSPORTATION LOSSES OF CONDENSATE

289. The PSC for Mid and South Tapti is silent on the disposal of condensate, i.e. whether it is gas or crude oil. PMT JV was treating the condensate as gas till December 2005. The transportation and processing of PMT gas was undertaken by ONGC through its South Bassein-Hazira offshore trunk pipeline and onshore Hazira facilities respectively and was governed by a settlement agreement of December 2005 between ONGC and PMT JV. In the settlement agreement, the condensate transportation losses from the Tapti delivery point to ONGC's Hazira Plant were to be determined by a condensate expert to be jointly appointed by ONGC and PMT JV. Pending determination of such losses, it was agreed to treat the Tapti condensate losses provisionally as 'zero'.

290. The non-determination of condensate losses during transportation was commented vide Paragraph 6.3.2 in C&AG of India (Union Government-Civil) Report No.19 of 2011-12-Performance Audit of Hydrocarbon PSCs. MoPNG in response

stated that JV had already shortlisted international agencies for assessment of transportation losses. As a way forward, the JV and Institute of Oil and Gas Petroleum Technology (IOGPT) of ONGC were working on the simulation model to firm up the scope of work, results of which were to be validated by a third party expert. It was observed that the condensate transportation losses have not yet been determined (February 2014) even after a lapse of 8 years from the settlement agreement reached in 2005. The PMT JV and IOGPT-ONGC had only decided (August 2012) the scope for determination of Tapti Condensate Transportation losses and were to start the process of selection of 'Expert' for determination of Tapti Condensate Transportation losses.

291. The delay in determination of condensate transportation losses has been detrimental to ONGC.

292. PMT JV in its reply to Audit (February 2014) and to MoPNG (July 2014) stated that matters that arise under a settlement agreement between the PMT JV and ONGC are outside the scope of the present audit conducted under Section 1.9 of Appendix C of the Tapti PSC. Without prejudice to this, it is stated that *"the condensate loss expert has now been appointed and are hopeful that the matter will be resolved within the next few months. The transportation losses determined by the independent expert will be applied retrospectively from 1 April 2005, and excess amounts paid by ONGC, if any, will be refunded (clause 4.4 of the settlement agreement). As such, ONGC should suffer no detriment".*

293. MoPNG in reply (July 2014) stated that *CAG needs to consider whether condensate will be lost when it is transported in a closed circuit pipeline. MoPNG added that any transportation loss paid to ONGC will be detrimental to this PSC by reducing Profit Petroleum. Hence, this issue does not warrant reply under PSC audit. It may be appropriate to raise the issue to ONGC when ONGC's accounts are audited.*

294. According to Audit, the reply needs to be viewed in light of the fact that the non-

fixation of transportation loss of condensate was brought out in the previous Audit Report No. 19 of 2011-12. While ONGC is considering internally 6 *per cent* as transportation and processing loss from condensate, the PMT JV is considering the loss as 'zero' from 2005 which was commented upon. It is also not out of place to mention that the ONGC was considered as a part of GoI while evaluating the bidding of PMT fields and the total revenue including the share of ONGC was considered as GoI share. In this context, the issue is appropriately raised under PSC audit in the last Audit Report and also in the current audit. The fact, however, remains that the condensate transportation loss is yet to be determined even after a lapse of 8 years from Settlement Agreement. The Audit, therefore, recommended that PMT JV may expedite the fixation of transportation losses of condensate pending for last 8 years that has impacted the interest of ONGC.

295. The Ministry in Action Taken Replies have stated that " a consultant M/s Worley Parsons Melbourne has already been appointed on 09.06.2014 by ONGC and the Companies to resolve the issue. A draft report has already been submitted in this regard".

296. On being asked has the transportation losses of condensate pending for fixation for last 8 years fixed now. The ONGC replied as under:

> "In order to resolve the issue, the technical expert ("condensate expert" as per settlement agreement) has been appointed by PMT JV in agreement with ONGC. Based on the report submitted by M/s Worley Parsons, the methodologies for working out the condensate loss during transportation have been agreed between ONGC & PMT JV and the consequential financial implications have also been finalized. The proposals for settlement are currently under the approval of the Management of ONGC & PMT JV".

RJ-ON-90/1 BLOCK

XVI. INTRODUCTION

297. The RJ-ON-90/1, an on land block is one of the pre-NELP exploration blocks awarded in Round IV of pre-NELP exploration rounds in May 1995 to Shell India Production Development (SIPD). The PSC was signed between GoI, SIPD and ONGC on 15 May 1995. Subsequently, SIPD's participating interest (PI) was transferred in three phases between September 1998 and June 2003 to Cairn Energy India Limited and Cairn Energy Hydrocarbons Limited (Collectively termed as "Cairn Energy"). Cairn Energy India Limited (CEIL) is the Operator of the block. The Block has 25 hydrocarbon discoveries (21 oil and 4 gas) made between July 1999 and November 2008. There are three distinct Development Area (Das) in the block approved by the MC to include commercial discoveries. Under the terms of the PSC, ONGC as the designated nominee of GoI, had the right, to take a PI upto a maximum of 30 per cent in each of three Development Areas viz. DA-I, DA-2 and DA-3. ONGC was also the licensee of the Block responsible for obtaining the Petroleum Exploration Licence (PEL), Mining Lease (ML) and payment of royalty/PEL/ML fees.

XVII. OBJECTIVE

298. The main objectives of the performance audit of hydrocarbon PSCs were to verify whether:-

- The systems and procedures of MoPNG and Directorate General of Hydrocarbons (DGH) to monitor and ensure compliance by the operators and contractors of the blocks with the terms of the PSCs were adequate and effective; and

- The revenue interests of the Government (including royalty and GoI share of profit petroleum) were properly protected, and adequate and effective mechanisms were in position for this purpose.

XVIII. AUDIT REVIEW

299. Audit, through their reports - No. 19 of 2011-12 (Performance Audit) and No. 24 of 2014 on Hydrocarbon Production Sharing Contracts, have highlighted instances of delayed exploration and appraisal activities, scope of better monitoring to ensure adherence to the provisions of the PSC which relate to issues of compliance. There

were delays in finalization of minutes of the MC meetings leading to delay in commencement of activities. The Works Programme and Budget (WP&B) approved by Operating Committee (OC) was not submitted to Management Committee (MC) in time and the approval of MC was eventually delayed. The delayed submission and approval of annual WP&B violated the timelines prescribed in the PSC. As per request of the Operator, GoI agreed to shift the delivery point from Barmer to Salaya with a condition that the GoI may designate multiple PSU refineries and approval for laying of a pipeline from Barmer to Salaya and Salaya to Bhogat in Gujarat was granted. The pipeline was delayed with a portion, Barmer to Salaya being completed after delay of about 10 months in May 2010 and the balance Salaya to Bhogat, scheduled for completion by 2010 being mechanically completed only in June 2014 (presently under commissioning) after expiry of almost four years from targeted completion. The delays contributed to increase in pipeline cost which rose to US$ 1108 million (March 2013) against the approved cost of US $ 941 million. The PSC provided that the GOI nominated refineries, however, could not uplift the RJ crude and, GoI granted marketing freedom to the Operator to sell the remaining crude to domestic private refineries. During the period of audit (2008-12), the sales to domestic private refineries from 2009-10 to 2011-12 ranged between 51.11 and 87.57 per cent of the total production, primarily due to the inability of the nominated GoI refineries to uplift the crude from the Block. Audit noted that a price for the crude oil would be agreed between the Parties and would be subject to agreement by the GoI. Audit, however, observed that price of the RJ crude was yet to be finalized by the GoI in the absence of which sale of RJ crude was taking place at a provisional price agreed between the Operator and the buyers. The issues highlighted by the audit have been dealt with in detail in the subsequent paras.

XIX. <u>EXPLORATION AND APPRAISAL ACTIVITIES</u>

A. <u>Delayed Relinquishment of Area</u>

300. The PSC stipulated an exploration period of seven years, also permitting an extension of upto three years. This extended exploration period expired on 14th May, 2005. At this stage, the operator was required to relinquish the entire area, except for discovery and development areas. However, out of the original contract area of 11,108

sq. km., a total area of 6678.10 sq. km. (including extended area of 1708.20 sq. km) was retained, which comprised of the following:

- 1859 sq. km. of development area in DA-1 field;
- appraisal area of 2884 sq. km. (Northern Appraisal Area); and
- an additional 1935.10 sq. km. of area in the southern part, which was not designated as a discovery or development area. This area was irregularly retained till 7 November, 2007 (due to non-submission of maps by the operator in time), when it was finally relinquished.

301. Further, out of the appraisal area of 2884 sq. km. in the Northern Appraisal Area:

- an area of 430.17 sq. km. was converted into Mining Lease [by Rajasthan Government for 20 years (DA-2 development area)] on 15th November, 2006.
- Out of the remaining area of 2453.83 sq. km., the contractor sought retention of the entire area for six months (from 15th November, 2006), but was allowed by MoPNG to retain an area of 879.50 sq. km. under PEL from 8th May, 2007 till 7th November, 2007.
- 822.00 sq. km. of the area of 879.50 sq. km. was converted into Mining Lease (DA-3 development area) on 6th November, 2007; however, the balance area of 57.5 sq. km. was deemed relinquished.

302. Audit has pointed out that the MoPNG in response to their observations have stated the following:

- The delays in relinquishment were procedural and did not have any commercial implications.
- No activity during delays in relinquishment had been reviewed by the MC, which would have an adverse material impact on the contract.
- Further, DGH had conveyed on 14th November, 2006 to the operator/licensee that except for the area of 430.7 sq. km. the remaining block area (2453.83 sq. km.) in the Northern Appraisal Area stood relinquished from 15th November, 2006.

B. Extension of Appraisal Period

303. MoPNG extended the stipulated exploration period of 7 years by 36 months in June 2002 and, in June 2005, approved another extension of 18 months (15 May 2005 to 14 November 2006) to complete appraisal of the Bhagyam and Shakti discoveries in the Northern Appraisal Area (NAA). In December 2006, the operator requested a further extension of six months for completing appraisal work in the NAA to cover up the work which was *inter alia* hampered for more than three months in view of severe floods in Rajasthan. DGH did not recommend further extension, since the appraisal work (for which the earlier 18 months extension was sought and agreed to) was already over. However, in May 2007, MoPNG granted a further extension of 6 months effective from 8 May 2007. Interestingly, the period of 6 months between 15 November 2006 and 8 May 2007 was not formally covered by extension.

304. Audit has stated that MoPNG in response to their observation have stated that the Government granted (8th May, 2007) six months extension on the basis of Cairn's track record with regard to survey, exploration and discovery, besides the fact that Cairn was quite confident of making more discoveries in the Northern Appraisal Area. However, the fact remains that this extension was beyond the PSC provisions.

305. On being asked about the rationale for giving repeated extensions to the operator beyond the provisions of PSC, the Ministry in their written reply stated that:

> **"**The exploration period of seven years as per PSC expired on 14.05.2002. The extension for exploration Phase-III for a period of three years till 14.05.2005 was granted by GoI under Article 2.6 of PSC. As per Article 2.6 the contractor is entitled to a further exploration phase of a period sufficient in accordance with good international petroleum industry practice which shall not exceed three consecutive contract years from the end of Phase-III. The GoI laid down a condition that any further extension of this block will not be sought by the contractor/operator under any condition, including the provisions of Article 9 which would not be applicable. The condition was laid down because Article 2.9 is applicable for extension for completing Appraisal Work on a discovery and not applicable for Exploration Work.
>
> **Article 2.9 of PSC: "**Where sufficient time is not available prior to expiry of the Exploration Period to complete the appraisal work on a discovery, at

the request of the contractor, submitted with a Work Programme for the appraisal the Government shall extend the Exploration Period for such period, not exceeding thirty (30) Months, as may be required for the appraisal work to be carried out by the Contractor in accordance with good international petroleum industry practice”.

Operator sought further extension by 18 months for Appraisal Work in northern extension of Shakti and Bhagyam fields. MoPNG, granted 18 months extension beyond 14.5.2005 to complete the appraisal work in the northern area of the Block as per provision of Article 2.9 of PSC. Operator requested for further six months extension for appraisal of KW-2 and KW-3 discoveries in erstwhile Northern Appraisal Area. MoPNG granted six month extension for appraisal of Northern Appraisal Area effective from date of approval under Article 2.9 of PSC under which extension for a period of not exceeding thirty (30) months for completing Appraisal Work on a discovery can be granted.

Hence all the extensions were granted as per PSC provisions.”

306. In response to a query of the Committee about the steps been taken to strengthen the PSC provisions, the ministry in their reply have stated that the most of the non compliance of PSC provisions related to notification of potential commercial interest, appraisal programmes and submission of Field Development Plans etc. has occurred as there is no provision in PSC for extension/ relaxation of these timelines. At the same time, if discoveries are not agreed based on non adherence to the PSC provisions, the explored reserves cannot be monetised. In view of above, Government has recently approved policy framework, for relaxations, extensions and clarifications at the development and production stage under the PSC regime for early monetisation of hydrocarbon discoveries where MC / DGH have been authorized to condone the delays and extension of timelines to certain extent after paying pre-defined fee. This will help in regularizing such unintended delays in notification of potential commercial interest, appraisal programmes and submission of Field Development Plans etc. in accordance with the PSC.

C. <u>Discoveries made during/after Exploration Period</u>

307. Audit has pointed out that the operator carried out exploration activities and made new discoveries within the discovery/development areas, as summarized below:-

Sl. No.	Name of the Discovery	Date of Discovery	Devel-opment Area (DA)	Remarks
1.	N-I	18.05.2006	DA-2	The exploration period ended on 14th May 2005. Eight discoveries indicated at serial nos 1 to 8 were made after the exploration period ended, i.e. during the first appraisal period from 15th May, 2005 to 14th November, 2006.
2.	GSV	04.07.2005	DA-1	
3.	N-C West	04.07.2005	DA-1	
4.	N-I-North	21.11.2005	DA-2	
5.	Bhagyam south	03.12.2005	DA-2	
6.	N-E	09.01.2006	DA-2	
7.	N-P	06.04.2006	DA-2	
8.	Shakti-NE-1	21.10.2006	DA-2	
9.	K-W-2	21.11.2006	DA-3	Three discoveries indicated at serial nos 9 to 11 were made during 15th November, 2006 to 7th May, 2007, i.e. the period between the first appraisal period (15th May, 2005 to 14th November, 2006) and the second appraisal period (8th May 2007 to 7th November, 2007).
10.	K-W-3	13.12.2006	DA-3	
11.	Saraswati-Crest-1	15.12.2007	DA-2	
12.	K-W-6	20.07.2007	DA-3	This discovery was made during the second appraisal period from 8th May, 2007 to 7th November, 2007.
13.	Raageshwari-East-1z/Tukaram	24.11.2008	DA-2	This discovery was made during the development phase.

XX. COMPLIANCE ISSUES

A. Delay in submission of Work Programme and Budget (WP&B)

308. Articles 6.7 & 9.11 of the PSC provided that the WP&B related to development and production operations would be submitted by the OC to the MC for approval not later than 31 December each year in respect of the Year immediately following.

309. Audit observed delays in submission of WP&B (2008-09 to 2011-12) by OC to MC and subsequent approval by MC.

310. The delays in submission of OC approved WP&B to MC ranged from 91 to 111 days for the years 2008-09 to 2011-12. Further, these WP&B were approved by MC taking 70 to 239 days. Thus, delayed submission and approval of annual WP&B violated the timelines prescribed in the PSC besides continuance of activities envisaged in the WP&B without approval of the MC.

311. The Operator stated (November 2012) that *FDPs were multi-year programs and the annual WP&B merely reflect phasing of the expenditure on year to year basis. In a typical multi-year project, what was more critical was the project sanction which existed by means of MC approved FDPs. Therefore, in the interest of timely project completion, the Operator continued with the project execution*. The Operator in its reply (July 2014) to the MoPNG also stated that *it endeavored to adhere to the timelines specified in PSC*.

312. MoPNG in its reply (June 2014) stated that *PSC provides that the contractor should submit the annual work program and budget to the MC by 31 December of the previous year. Though there is no time line for grant of approval by MC, presumably the MC has three months (90 days) time for approval of the annual work program and budget before the year commences. With this background, the time taken by MC for approval of the budget is not found to be materially different and the PSC timelines were generally adhered to*.

313. To Audit, the reply of the Operator was not acceptable as WP&B authorizes a particular activity within the approved budget. Approval of the FDP does not preclude the need to adhere to the timelines prescribed in the PSC for timely approval of WP&B. The contention of the MoPNG that PSC timelines regarding WP&B were adhered to is also not tenable as there were delays both in submission of WP&B by OC to MC and in approval of WP&B by MC.

314. Under the PSC, the MC generally functions on the recommendations of the OC. Therefore, the significance and relevance of a functioning OC need not be over emphasized. The instances referred to above were primarily governance issues which manifested in terms of delays with consequential impact on production and could be addressed when the OC and the MC discharge their functions working with the spirit of being collective (and not fragmented) units in their respective domains with an active (and proactive) approach.

315. There is a need for approval of WP&B before commencement of the year. The WP&B is the only document, which authorizes a particular activity within the approved budget. Therefore, all the stakeholders including DGH/MC should work in coordination

to ensure timely approval of WP&B as PSC mandates that MC approves the development and production budgets on annual basis.

316. The Audit, therefore, recommended that MoPNG/DGH may take action for timely approval of the WP&B in future.

317. The Ministry in their Action Taken Replies have stated Audit exceptions has been noted and Annual work programme budget will be approved by MC as per PSC timelines.

318. The representative of ONGC in their presentation made before the Committee on 21st March 2016 have stated that:

> "Audit exception has been noted and all proactive steps are taken to enable timely submission & approval of WP&B.
>
> It is to mention that WP&B for FY 2015-16 was endorsed by OC on 31st Dec 2014 and was approved by MC before 31st March 2015, in line with the PSC timelines. Also, WP&B FY 2016-17 has been considered by MC in its meeting held on 12th March 2016".

B. <u>Short Payment of Profit Petroleum to GoI - Adjustment of Shipping Cost beyond delivery point</u>

319. Article 27.2 of PSC, *inter alia* provides that the contractor would be responsible for all costs prior to the Delivery Point[20] and the GoI or its nominee (for evacuation of crude) would be responsible for all costs beyond Delivery Point. Thus, the buyer has to incur expenditure beyond the Delivery Point. As an interim arrangement, the GoI allowed (October 2009) the Contractor to establish an interim delivery point at Kandla port for transporting the crude to the GoI nominees (HPCL and Mangalore Refineries and Petrochemicals Limited (MRPL). Costs incurred upto Kandla for transfer to GoI nominees alone would thus be cost Audit observed that HPCL did not take any crude against allocation of 0.80 MMT and the Operator transported crude from October 2009 to June 2010to MRPL and RIL through the delivery point at Kandla (approved to be used for crude transportation to MRPL and HPCL only). Audit noticed that though the

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[20] *As per Article 1.23 "Delivery Point" means, except as otherwise herein provided or as may be otherwise agreed between the Government and the Contractor, the point at which Petroleum reaches the outlet flange of the delivery facility and different delivery points may be established for purposes of sales to the Government and other sales.*

PSC stipulates that the transportation cost beyond delivery point is to be borne by the buyers, yet the Operator incurred US$ 8.87 million towards shipping of crude to MRPL and RIL beyond designated delivery point (Kandla) and adjusted it from the revenues.

320. The recovery of US$ 8.87 million had resulted in short payment of PP of GoI by US$ 1.77 million (i.e. 20 *per cent* of US$ 8.87 million).

321. The Operator stated (November 2012) that *since HPCL had expressed its inability to uplift the crude, sales to RIL (along with MRPL) were made through trucking and without sales to RIL, the production schedule would have suffered badly*. It further stated that *its request to GoI for regularization of sale to RIL through trucking was under consideration*. The Operator in its reply (July 2014) to the MoPNG stated that *the sale to RIL was an Arms-Length Sale and accordingly, the shipping costs incurred beyond delivery point were deducted from the sale price and thus, the adjustments done were as per PSC*.

322. MoPNG in its reply (June 2014) stated that *the contractor was advised by DGH on 29 August 2012 disallowing cost recovery of US $ 8.88 million, followed by a reminder on 31 January 2014*.

323. To Audit, the reply of the Operator was not acceptable as the adjustment of shipping cost of US$ 8.87 million beyond the GoI designated delivery point was in contravention of PSC provisions and resulted in short payment of profit petroleum to GoI.

324. Audit therefore recommended that The Operator should carry out cost recovery in accordance with PSC provisions as any deviation in this regard would impact payment of PP to the GoI.

325. The Ministry in their Action Taken Replies have stated that:

> "As noted by CAG, the amount of US$ 8.88 million was disallowed as Contract Cost".

326. The representative of ONGC made power point presentation before the Committee on 21st March, 2016 on the point and stated that: Despite allocation by GoI, HPCL had eventually expressed the inability to buy the crude oil and MRPL had refused

to lift the crude oil from Kandla Port. Thus sales to RIL & MRPL were made to their refineries through marine vessels and consequently the cost of USD 8.87 MM was incurred towards the shipping cost. Without these sales, the production would have suffered badly.

327. The same expenditure has been adjusted from the revenue as per provisions of article 19.3 of PSC which provides for that in case of Arm's length sales, the delivery point shall be the outer flange of the export terminal or the customer's facility in India or as the case may be.

328. In the event of absorbing shipping cost by the buyer, the sales price at Kandla would have been net of shipping charge". However, the Ministry in their presentation submitted that contractor has been advised of disallowance of the cost, differential profit petroleum will be collected.

C. <u>Delay in approval of Optimization Concept</u>

329. With the experience gained during the development of Mangala field, the Operator proposed (April 2010) an optimization concept for Bhagyam Field which was deliberated by the MC on 20 August 2010. MC's final approval was communicated on 13 December 2010. Thus, approval of optimization concept took 115 days from the date of MC meeting. This resulted in delayed commencement of activities.

330. The MoPNG replied (June 2014) that *the Bhagyam optimization concept was deliberated in the Management Committee (MC) meeting held on 19 July 2010 wherein the MC advised the Operator to formalize the concept through the Operating Committee (OC)*. The OC Resolution was ultimately submitted by Operator *on 20 August 2010 which was reviewed by MC. The MC Resolution (MCR) was signed by DGH on 11 October 2010 whereas the signing of MCR by remaining MC representatives was completed on 13 December 2010. It further stated that substantial deliberation took place after the MC meeting on the concept optimization and the minutes were signed by circulation without waiting for a physical MC meeting in order to expedite the decision making*.

331. The Operator in its reply (July 2014) to the MoPNG stated that *it would take up this point in the MC and mutually agree on the ways and means to ensure timely approval/sign-off of MC meetings*.

332. To Audit, the fact remained that despite deliberations on the Bhagyam concept in MC meeting on 20 August 2010, the minutes constituting approval of the MC for execution of the activities were signed only on 13 December 2010 after nearly four months, resulting in underutilization of the budget during 2010-11.

333. Audit therefore recommended that, All stakeholders should ensure that the minutes of MC meetings are firmed up in a timely manner to avoid delays in execution of projects.

334. Ministry in their Action Taken Replies stated that:

> "Audit exception has been noted and the minutes of MC will be finalized as per PSC timelines".

335. The representative of ONGC in their presentation made before the Committee on 21st March, 2016 submitted that after MC review of the proposal, the substantial deliberation took place on the concept optimization and the minutes were signed by circulation.

XXI. NON-LIFTING OF CRUDE OIL BY NOMINATED GOI REFINERIES

336. The GoI decided (February 2008) to nominate multiple GoI refineries as GoI nominees for evacuation of RJ crude. The PSU refineries, *viz*. IOCL, HPCL, BPCL and MRPL, had also indicated (October 2008) to the GoI that they could absorb 3.5 to 4.2 MMTPA against estimated production of 7.5 to 8.75 MMTPA from the Block. Consequently, the GoI nominated (March 2009) MRPL, HPCL and IOCL to offtake part of the planned production during the year 2009-10 and 2010-11. The quantum of allocation of crude to GoI refineries and actual offtake from 2009-10 to 2011-12 was as under:

(Figures in MMT)

Year	Allocation			Actual offtake		
	MRPL	HPCL	IOCL	MRPL	HPCL	IOCL
2009-10*	0.20	0.30	0.20	0.20	-	-
2010-11*	0.40	0.50	1.50	0.07	-	0.42

2011-12	-	-	1.50	-	-	0.98
Total	0.60	0.80	3.20	0.27	-	1.40
	0.60+0.80+3.20=4.60			0.27+1.40=1.67 (36 *per cent*)		
*Upto 14 June 2010 the evacuation of RJ crude was through tankers						

337. Audit, however, noted that despite expressing their willingness and ability in July 2005 and October 2008 to take and process the RJ crude, the nominated GoI refineries failed to uplift their allocated share of RJ crude on account of following:

- During the year 2010-11, MRPL did not uplift its entire share of allocated crude and discontinued lifting crude in June 2010 due to inability to process the RJ crude until the Coker unit was installed in its refinery.
- HPCL did not uplift any crude during 2009-10 and 2010-11 despite allocations stating that lifting of crude from Kandla (designated delivery point for MRPL/HPCL) was not economical for processing at its Vizag refinery.
- IOCL had confirmed to uplift the allocated crude subject to commercial viability.

338. Thus, the failure of the nominated GoI refineries to uplift their allocated share of RJ crude led to:

- the controlled/moderated production which resulted in shortfall of 0.41 MMT as indicated by the comparison of actual production (0.45 MMT) with forecast production (0.86 MMT) during 2009-10.
- the grant of marketing freedom (October 2009) to the Operator to sell the unallocated portion of the crude produced from the Block to domestic private refineries, which took 51.11 to 87.57 per cent of the total production from the Block from 2009-10 to 2011-12.

339. MoPNG in its reply (June 2014) stated that *the crude oil produced from RJ-ON-90/1 was heavy containing high wax which made the crude refining a tough task. Further, the difficulty posed by MRPL's inability to lift crude oil as planned initially was overcome by MOP&NG and delay in production was halted by nominating multiple refineries including the private refineries*.

340. Audit took note of the MoPNG's views that crude oil produced from RJ-ON-90/1 was heavy containing high wax. However, the fact that the PSU refineries as nominees

of GoI failed to take even the allocated share of RJ crude (the entire quantity of which was mandated for evacuation by GoI nominees only under Article 18.2 of PSC) confirmed the lack of required preparedness.

341. The Ministry in their Action Taken Replies have stated that:

> "Audit has noted the fact that the crude oil produced from RJ-ON-90/1 was highly viscous containing high wax highly viscous containing high wax which made the crude refining a tough task. Considering the economic implications in making changes in the design of the refineries, the PSUs restricted the off-take to protect their economic interest"

342. The representative of ONGC made power point presentation before the Committee on 21st March, 2016 submitted that:

- ➢ RJ Crude is heavy containing high wax content which made the crude refining a tough task.
- ➢ MRPL had to discontinue the supply because of Technical reasons.
- ➢ Supply is being made to IOC for their Koyali & Panipat refineries.

  Supply to MRPL has been started again from December 2015 after the commissioning of their Coker unit"

XXII. NON-FIXATION OF PRICE OF RJ CRUDE DESPITE PRODUCTION FROM THE CONTRACT AREA SINCE AUGUST 2009

343. Article 19.2 of the PSC provides that a price for the crude oil for each calendar month or such periods as may be agreed between the Parties[21] would be determined in terms of US$ per barrel. Article 19.6 of the PSC also provided that the calculation, basis of calculation and the price determined would be supplied by the Contractor (CEIL, CEHL and ONGC) to the GoI and would be subject to agreement by the GoI before it was finally determined and pending final determination, the price determined by the Contractor would be used.

344. As the GoI nominee refineries were not lifting the allocated quantity of crude oil

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[21] *'Parties' means the parties signatory to this Contract including their successors and permitted assigns under this Contract. Accordingly, at present, parties to this Contract are the GoI, ONGC Limited, Cairn Energy India Limited and Cairn Energy Hydrocarbons Limited.*

allocated to them, the GoI allowed (October 2009) marketing freedom to the contractor to sell the remaining quantity to domestic private refineries stipulating that the net back crude price realized by the contractor would be as per the PSC and not be less than the International price for the benchmarked crude price. The Operator informed (June 2010) the GoI that pursuant to GoI approval, the Operator had entered into Term Sheet Agreements with the domestic private refineries (RIL and EOL) and the pricing for these refineries was based on the formula agreed with GoI nominees (IOCL) with additional US$ 0.15 per barrel for pipeline sales and US$ 0.75 per barrel for coastal supplies.

345. Audit observed that:

- The price formula for working out the price of crude oil is yet to be agreed to by MoPNG and the sales made to the GoI nominated refineries are based on the price agreed between the Operator and buyers which was based on the average of the daily mean values of the high & low price of Bonny Light (Nigerian) crude assessments as published in Platt's. Further an additional discount of 2.14 *per cent* was allowed off the benchmark crude (Bonny Light) on account of additional cost incurred by buyer for transferring & handling of crude oil at buyers refinery due to high pour point and high viscosity of Mangala crude.
- The international pricing expert, engaged (September 2009) for determination of crude price, had submitted the draft report to GoI in April 2010 which was shared by the GoI with the stakeholders in July 2010. *Despite subsequent discussions with the stakeholders, the decision of the Government regarding the pricing of RJ crude was not available on record (July/August 2012).* In the absence of GoI agreed price, the sales were continuing based on an agreed pricing formula between the Operator and buyers.
- The Term Sheet Agreements executed (June 2010) by the Operator with private refineries (RIL/EOL)[22] were based on agreed price with no provisions for revision of price with retrospective effect and the private sector refineries have expressed inability to agree to a provisional pricing arrangement with retrospective impact. The GoI while informing (15 June 2010) the Operator that the position taken by the domestic private refineries with regard to revision of price was not acceptable, advised (July 2010) that sales made to these refineries be on provisional prices until a final decision was arrived at by the GoI. GoI also asked the Operator to sell the shortfall quantities to these refineries in the year 2010-11 only if

[22] *RIL-75000 Barrels/day and EOL 30000 barrels/day.*

they agreed to the pricing conditions. Despite these directions from the GoI and pending finalization of pricing by the GoI, crude sales to these refineries took place during the year 2010-11 and 2011-12.

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

- *Article 19 dealt with three classes of sale transactions: a) arm's length transactions, b) sale to Government/ Government nominees and c) other than arm's length transaction. As per the Contractor, all sale transactions were considered as falling under the 1st two categories.*
- *Article 19.3 dealing with arms' length transactions did not stipulate any specific method of pricing, as the price would be market determined. Whereas Article 19.4 dealing with sale to Government /Government nominees stipulated a general method of pricing linking the price to international price of crude oil.*
- *Article 19.6 stipulates that unless the Government or Government Company raised an objection to a price, the last established price would be used. As the prices have been viewed as at arm's length, Government has not objected, so far, to the prices charged by the Contractor. In the absence of discovering any discrepancy, the prices could be treated as firm for Profit Petroleum and Royalty.*
- *Audit may report on the integrity of the price charged to the refineries, particularly whether any transaction is not at arm's length.*

347. The reply of the MoPNG was not acceptable to Audit on account of following:

- MoPNG had indicated (July 2010) that the price charged was to be provisional. The PSC provisions provide that the price is *subject to agreement* of GoI. GoI (MoPNG) had communicated (July 2010) that the prices charged were to be provisional. In fact the prices charged has not yet been agreed to by GoI though such agreement is mandated in the PSC.
- In the same communication, MoPNG had categorically stated that the sales to domestic private refineries were not to be construed as Arms' Length Sales. The instant reply of the MoPNG appears to contradict this position.

348. In view of above and the fact that pricing belonged to the domain of the GoI, it was difficult for Audit to comment on the integrity or otherwise of the price charged from refineries and whether any transaction was Arm's Length Sale or not till the same was approved by the GoI in terms of PSC provisions.

349. Audit accordingly recommended that GoI should promptly finalize the price for

the RJ crude so that the calculation of the PP, Royalty etc. can be made on firm basis.

350. The Ministry in their Action Taken Replies stated that:

> "The Contractor has crude oil pricing freedom. In the absence of any issue of affiliated transaction, the intervention of Government is not envisaged in the PSC".

351. ONGC in their presentation made before the Committee on 21st March, 2016 submitted that:

> "Basic pricing formula agreed by JV with the IOC is being used with the private refiners also. Formula was finalized with IOC at Arm's length basis".

352. The Ministry during the course of oral evidence in that presentation submitted that:

> "PSC provides for Government intervention when price is not at arms' length. PSC provides for Arm's Length sale of Crude Oil".

XXIII. <u>AWARD OF CONTRACT BEYOND PSC PROVISIONS</u>

353. The operator awarded contracts for procurement of goods and services to indigenous and foreign vendors. During the course of audit, 41 contracts in respect of which payment valuing more than one million US$ was made during the years 2006-007 and 2007-08 were reviewed. It was observed that:

- In three cases, payment of US$ 89.45 million was made against contracts awarded on nomination or on single financial bid basis;
- In one case, payment of US$ 1.49 million was made against the contract awarded without assessing reasonability of rates; and
- In two cases, payment of US$ 20.63 million was made against contracts extended beyond contractual provisions, without availing economies of scale.

354. In response, MoPNG stated (July 2011) that any amount assessed by audit in the final report that should not be considered would be considered for appropriate action for deletion from contract cost. In this connection, we recommend that MoPNG validate the award of contracts failing under the categories listed above, so as to draw assurance that Government's interest was protected.

355. The Ministry in their Action Taken Replies has stated that:

"Operator has been advised to provide clarification/reply on issues raised in the report. Amount assessed by CAG in the final report will be considered for appropriate action".

356. The representative of ONGC made presentation before the Committee on 21st March, 2016 and submitted that:

"The tendering process is resorted to by the operator, however, approval for award of the contracts is endorsed by the OC.

During this period initial phase of the Field Development was in progress with efforts to commence early production and the contracts were endorsed by OC in the best interest of the JV.

In some cases, during bidding, only one bidder was technically qualified and in some cases, contracts have been extended by the operator in the operational interest. However, one case awarded on nomination basis was not agreed by MC".

357. Further, the Ministry in their presentation submitted:

"Operating Committee (OC) consisting of members from ONGC and Cairn monitores the award of procurement contracts, whose CAG has not identified any affiliated transaction, undue benefit to the Contractor, negligence or fraud".

PART-II

OBSERVATIONS/RECOMMENDATIONS

<u>Introductory</u>: The Committee note that with the reforms in the economy, the Government decided to liberalize the framework governing the oil and gas Exploration and Production Sector hitherto the preserve of the Government Sector. In early 1990s, Government of India invited foreign and domestic Private Sector Companies to participate in the development of discovered oil and gas fields, and in some cases, fields partially developed by the National Oil Companies (NOCs)-Oil and Natural Gas Corporation Limited (ONGC) and Oil India Limited (OIL). During pre-NELP exploration bid round, National Oil Companies (NOCs) were licensees of the blocks and had right to take participating interest upto 30% in development phase. Government awarded small and medium sized discovered and producing oilfields as well as some exploratory blocks to foreign and domestic Private Sector Companies in this round. In 1997, the Government formulated a New Exploration Licensing Policy (NELP) which was notified in 1999 with the objective of not only attracting private capital but also introducing the technical expertise and efficiency of global players in the field. Under the NELP regime, both NOCs and private companies were allowed to participate in the bidding of acreages on a level playing field and blocks were awarded through open international competitive bidding and after award, the PSC(Production Sharing Contract) was signed between Contractor parties and the Government of India . The PSCs for specific fields/ blocks laid out the roles and responsibilities of all parties, stipulated the detailed procedures to be followed at different stages of exploration, development and production and also indicated the fiscal regime (cost recovery, profit sharing etc) . Though, under both pre-NELP and NELP regimes, period of exploration was regulated by the terms and conditions of PSC and Petroleum Exploration License (PEL) and petroleum mining was regulated by terms and conditions of PSC and Mining Lease (ML), the content of PSCs varied substantially among those for discovered fields, pre NELP exploratory blocks and

NELP blocks and even within different NELP rounds. The principle underlying the PSC (Production Sharing Contracts) model, under the NELP, involved a sliding scale for profit sharing between the Government of India and the Contactor based on the Pre Tax Investment Multiple (PTIM) i.e. an index of the accumulated net cash flow to the contractor relative to the accumulated expenditure on exploration and development activities. The exploration risk viz. the costs incurred in searching for oil and natural gas, without certainty of discovery, were to be borne by the Contractors as they incurred capital expenditure towards the discoveries and it was only when hydrocarbons were discovered and assessed to be commercially viable, the Contractor had the right to recover costs from the revenue streams accruing from sale of oil and gas. The balance revenue , termed as Profit Petroleum (PP) after the Contractor had recovered all his costs was to be shared between the Contractor and the Government. The Government share of revenues became significant only when the production reached substantial levels and the Contractor had recovered his accumulated costs. Further, PSC also contemplated a Management Committee (MC), chaired by a Government of India representative, with the responsibility to approve field development plans, as well as annual work programmes and budgets for development and production operations to ensure that the expenditure proposed to be incurred as well as actually incurred by the Operator did not adversely affect the Government's revenue interests.

Article 25 of the PSC stipulated 2 levels of Audit by independent auditors viz. a) Appointed by the Management Committee; b) Appointed by the Government. The C&AG undertook a Special Audit (2nd level audit) of four blocks viz. Panna-Mukta, Tapti, KG-DWN-98/3 and RJ-ON-90/1 out of the eight blocks on the request of Secretary, MoPNG made in the wake of large stakes of the Government in the form of royalty and profit petroleum, and concerns voiced in some quarters about the capital expenditure being incurred by some Contractors in the development projects awarded under NELP. The C&AG Audit included scrutiny of the records of the MoPNG and DGH for the period 2003-04 to 2007-08 and supplementary scrutiny of the records of four operators for the period 2006-

07 and 2007-08. The findings of the C&AG Audit have been incorporated in their Report No 19 of 2011-12 on "Performance Audit of Hydrocarbon Production Sharing Contracts". C&AG accepted the request of MoPNG to audit 8 blocks and undertook Audit of four blocks PY-1, PY-3, Kharsang and CB-ON-7 for the years 2007-09 and initiated Performance Audit of the implementation of the Hydrocarbon PSCs at the MoPNG and DGH and financial and propriety audit at the Operator's premises in respect of the rest of the four blocks viz. KG-DWN-98/3, Panna-Mukta, Tapti and RJ-ON-90/1 for 2008-12.The observations emanating from the aforesaid Audit are contained in C&AG Report No. 24 of 2014. The Committee took up examination of both the Reports simultaneously as these are based on the Audit of the same blocks over different periods. The Committee note that the C&AG in their first Report had not quantified the costs to be disallowed as per their findings under the PSC provisions by the Operators. The Committee further note from the submission of the Secretary, MoPNG that in the absence of quantification of the deficiencies by the C&AG, it was not possible for them to act thereupon. However, in their second Report, C&AG have done the quantifications of the costs to be disallowed wherever price discovery was possible. The Committee's examination of the subject and their observations/ recommendations on the issues raised in both the Audit Reports are detailed in succeeding paragraphs.

2. <u>Production Sharing Contracts and the Cost Recovery:</u> The Committee note that the basis on which the share of the Government in Profit Petroleum is decided is called 'Pre-tax Investment Multiple' which is the ratio of cumulative net cash income to the cumulative exploration and development cost. The cumulative investment remains as a denominator and it helps to prevent the contractor to manoeuvre on annual basis i.e. by increasing the production in a year or increasing the cost in a year, the Contractor will not be able to take advantage. The Committee note that whatever revenue comes in, the Contractor will recover his cost out of the first 90 percent; the 10 percent which remains with him is called profit petroleum and the sharing formula in that 10 percent is that the contractor will take ₹ 9 (90 percent) and the Government will get ₹ 1 (10 percent)

i.e. the Government's profit will jump from 10 percent to 60 percent if the PTIM changes from 1.5 to 3.5. But the Audit has pointed out that Government's share comes down when the cumulative investment goes up and the investment multiple comes down. The Ashok Chawla Committee on 'Allocation of Natural Resources' had highlighted that the IM-based profit sharing system "gives incentive (to an operator) to increase his investment or front-end his work plan in order to see that the threshold where Government's profit take rises rapidly is not reached." The Chawla Committee had further pointed out that once the PTIM crosses 2.5, the Government's share of profit increases dramatically for which the operator may adopt all investment and strategies possible to ensure that the PTIM stays within the 2.5 limit. The Ministry submitted that based on experience, over so many years of NELP, it was seen that today 90 per cent of problems, which it was facing, and all arbitrations and litigations, were basically related to cost recovery.The Committee further note from the submission of the Ministry that the formula has been revised keeping in mind the C&AG's observations and the Ashok Chawla Committee's recommendation and its own experiences, and a revenue sharing model contract in place of the present profit sharing regime has been introduced, for future bidding rounds under new Hydrocarbon Exploration and Licensing Policy. The Committee while appreciating the switch over to a new model desire that , in case of already signed 249 PSCs, it becomes imperative that the contentious issues arising there from are resolved in an amicable manner with prospective application.

3. <u>Roles and functions of DGH</u>: The Committee note that the roles and functions of DGH encompass two sets of functions with potential conflict of interest - an upstream regulatory function and a function of rendering technical advice to the GoI. Audit had, therefore, observed that technical advisory and related functions should be discharged by a body completely subordinate in all respects to MoPNG and functions of regulatory nature should be discharged by an autonomous body, with an arm's length relationship with GoI. The Committee note that Committee on Open and Competitive Mechanism for Allocation, Pricing

and Utilization of Natural Resources (Ashok Chawla Committee) in its Report on PSCs had also observed that transparency in the management of contracts and associated considerable financial implications should be enhanced by increasing the independence of the regulatory mechanism, clarifying the separation of the policy maker, regulator and the operator and bringing the decision making process into the open. The Committee take note of the reply of the MoPNG that regulatory functions are demarcated & laid down by way of contract terms, Act and Rules; DGH is ensuring compliance of regulations by Contractors and role of technical advisory is discharged by DGH under the direct control of MoPNG and a separate study by Boston Consulting Group(BCG) was done by MoPNG before taking future course of action. The Committee observe that long delays in operational decision making, budget approvals, huge administrative burden of conducting cost audits, disputes arising between the government and operating companies on matters of cost recovery, information asymmetry and the potentially misaligned incentives are affecting the management of the PSCs by the Government. The Committee are of the opinion that the first step towards better management and effective implementation of the provisions of the PSCs would be to strengthen DGH and instead of filling places with deputationists for 3-5 years , a separate cadre of technical experts should be constituted for the technical and advisory functions of DGH. Further, the Ministry will have to consider separating regulatory functions as technical experts cannot be strained to double up as regulators and also policy makers cannot possibly be effective regulators. The Committee are of the opinion that the mandate of extant Petroleum and Natural Gas Regulatory Board (PNGRB) "to regulate the refining, processing, storage, transportation, distribution, marketing and sale of petroleum, petroleum products and natural gas excluding production of crude oil and natural gas so as and to ensure uninterrupted and adequate supply of petroleum, petroleum products and natural gas in all parts of the country" may be extended/ strengthened to include the exploration, development and production of crude oil and natural gas for regulating the PSCs . The Committee opine that

since a large number of PSCs have already been signed and RSCs will be signed in future, the Ministry should take the decision in this regard at the earliest.

4. <u>New gas pricing policy</u>: The Committee note that CCEA approved a new gas pricing policy in 2014 based on the modification of gas pricing formula proposed by the Rangarajan Committee with prospective application and as per the formulation approved ,upward revision in gas prices would be approximately 75% less as compared to the price arrived at using Rangarajan formula, approximately 80% of the additional revenue due to revision in gas price would go to the Government companies and Government would get additional revenue of approximately Rs. 3800 crore per annum on account of higher royalty, higher profit petroleum and higher taxes. The Committee further note the Government is considering incentivizing gas production from deep-water, ultra deep-water and high pressure-high temperature areas, which are presently not exploited on account of higher cost and higher risks and a proposal is under consideration for new discoveries and areas which are yet to commence production, first, to provide calibrated marketing freedom; and second, to do so at a pre-determined ceiling price to be discovered on the principle of landed price of alternative fuels. The Committee while appreciating that the Government has already initiated steps to provide marketing and pricing freedom in a calibrated manner to be produced from the difficult areas such as deep water, ultra deep water, high pressure and high temperature reservoirs with a upper cap on pricing and also pricing and marketing freedoms for the fields to be auctioned under the Discovered Small Fields Policy and blocks to be offered under new Hydrocarbon Exploration and Licensing Policy are of the view that care should be taken to ensure that gas is neither sold at very high prices as the ceiling price is dependent on prices of alternative fuels and nor at very low prices to benefit some parties on the pretext that it is being sold below the ceiling price.

<u>KG-DWN-98/3 Block</u>

The KG-DWN-98/3(KG-D6) Block with a contract area of 7645 sq.km., classified as 'deepwater block' with water depth ranging from 400 to 2700 m, was awarded to a consortium led by Reliance Industries Limited with a Participating Interest of 90% and its JV partner Niko Resources Limited(10%) in April, 2000. In 2011, RIL assigned its 30% share to BP Exploration (Alpha) Limited but continued to remain the Operator of the Block. Based on exploration activities between 2002 and 2012, a total of 19 discoveries have been made in the Block. Out of these 19 discoveries, one discovery is primarily an oil discovery and the remaining are gas discoveries.

A. The Committee note that the Contractor has invoked arbitration on the following:

- **Disallowance by GOI of Cost for fall in production rate that under utilized the facilities;**
- **Disallowance by GOI of three appraisal wells;**
- **Inclusion of marketing margin by GOI in sales revenue for profit sharing; and**
- **Exclusion of Parent Company Overhead and affiliated transactions for profit sharing.**

5. The Committee find that the Contractor has invoked arbitration in almost all the cases where Government has disallowed the costs. The Committee also note that the Ministry in their submission before the Committee agreed that there were anomalies in the provisions and the Ministry was learning over the process right from the pre-NELP stage. The Committee further find that a "policy framework for relaxations, extensions and clarifications at the development and production stage under the PSC regime for early monetization of hydrocarbon discoveries" was issued by the Ministry in November 2014 to rectify the anomalies noticed by them in practical implementation of the provisions of the PSCs. The representative of the Ministry, during the evidence, on a query regarding how to

reduce litigations and arbitrations stated that " under the new policy where it has moved away from the production-sharing to revenue-sharing contract it will not look at the day-to-day management like cost recovery and other things. It would only be interested as to how much production operator is doing; how much revenue he is getting; and out of which how much he will share with the Government which he has to declare upfront in a formula while bidding and that will be followed". The Committee while appreciating that the Ministry has learnt its lessons are apprehensive about the status of issues between the Government and the Contractors that have been lingering on due to the original provisions which have now been relaxed. The Committee are of the view that a strong dispute resolution mechanism should be put in place to address the concerns of both parties and further desire that the Ministry decide its course of action in such cases and apprise them.

B. The other major audit observations in respect of KG-D6 block are as under:

- **Non- relinquishment and declaration of entire contract area as discovery area;**

- **Award of 10 specific contracts of which 8 were awarded on the basis of a single financial bid;**

- **The review of DoC in respect of three discoveries, viz. D29, D30 and D31, was to be completed by MC by August 2010. However, due to lack of adequate production testing data, DGH rejected the DoC proposal. The issue was reopened after almost three years from the date when it was rejected by DGH and was being considered;**

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

- **Change orders/ post contract modifications affected by the Contractor.**

6. <u>Non- relinquishment of contract area :</u> **The Committee note that since the Contractor was allowed to enter the second and third exploration phases without relinquishing 25 percent each of the total contract area and to retain the entire Contract Area by treating it as 'discovery area' at the end of Phase-I and Phase-II, Audit had recommended that MoPNG should review determination of the entire contract area as discovery area strictly in terms of PSC provisions as contained in Article 4.1 and 4.2 and delineate the stipulated 25% relinquishment area at the time of the conclusion of the 1st and 2nd exploratory phases and then correctly delineate the discovery area, linked to wells or wells drilled in that part, without considering any subsequent discoveries. The Committee also note from the reply of MoPNG that it has applied appropriate provisions as deemed fit as per Article 4 that deals with the Contractor's right to retain and relinquish the Contract Area in phases and permits the retention of the 'discovery area' by the Contractor at the end of exploration phase I and II for further exploration and appraisal operations and Article 3.11 that deals with retention of portions of Contract Area beyond the exploration phases on account of development operations . Further, MoPNG in its reply have submitted that the discoveries made in phase-I were in plio-pleistocene zone and the discovery area demarcated is related with the plio-pleistocene stratigraphic level. However, the area demarcated separately in subsequent phase i.e. 5445 sq. km. is related with different stratigraphic level, therefore, discovery area was related with the discovery made at specific stratigraphic level and retention of discovery area was in accordance with article 1.39 of PSC. The Committee also note that Audit in its latest report have recommended that , pragmatically, MoPNG should accept sharing of exploration cost of only those of the wells which resulted in a commercial discovery and disallow the cost recovery already effected by the Operator on the remaining wells. The Committee take note of the MoPNG's concurrence, though delayed , to the retention of the entire Contract Area as Discovery Area by the Contractor till the conclusion of Phase III which was based on 3D seismic surveys of the Block insisted upon by the DGH, which was technically qualified to take such decisions. The Committee also note that**

though under NELP-I to NELP-VII, the provision of relinquishment of 25 percent contract area was there but from NELP-VIII onwards, the operator(s) need not relinquish any area. The Committee after taking into consideration the observations of C&AG, the submissions of the operator and the Ministry and the provisions of the PSC particularly Article 4.1 of the PSC which states that "..in the event Development Areas and Discovery Areas exceed 75%, the Contractor shall be entitled to retain to the extent of Development Areas and Discovery Areas" are of the opinion that delineating Development and Discovery Areas require technical expertise and accordingly the MC and DGH on the request of the Contractor allowed the contractor to retain the 'Contract Area' as the 'Discovery Area' and ,therefore, the exploration costs incurred by the Contractor on unviable discoveries cannot be disallowed as the Contractor is entitled to recover Contract Costs out of a percentage of the total value of petroleum produced and saved from the "Contract Area" as per the PSC.

7. <u>Award of contracts on the basis of a single financial bid:</u> Audit found that the payments during 2006-07 and 2007-08 revealed instances of huge procurement contracts where it could not derive assurance as to the reasonableness of the costs incurred, primarily due to lack of adequate competition i.e. award on single financial bids; major revisions in scope/ quantities/ specifications; post price bid opening; substantial variation orders-with consequential adverse implications for cost recovery and GoIs financial take. The Committee note the observation of the Audit that since any commercially prudent private acquisition would have also attempted to generate competition and thereby obtained the most competitive price which was not perceptible in the aforementioned process, MoPNG may carefully review in depth the award of 10 specific contracts (of which 8 were awarded to Aker Group companies) on the basis of single financial bid. The Ministry in their reply, however, instead of taking up any review, have stated that the Operating Committee monitored the contract award as per Appendix F of PSC and C&AG did not quantify the impact and also did not find any affiliated transaction or fraud

to invalidate the integrity of procurement. The Committee while taking a serious view of the MoPNG's reply that in absence of any quantification, action cannot be taken opine that MoPNG has been vested with the resources of the country in fiduciary capacity and therefore has the inherent responsibility to ensure that they are exploited in the interests of the country and accordingly, keeping a check on the outflow of resources in the form of Cost Petroleum is an inseparable part of that responsibility. The Committee, therefore, desire that the Ministry should develop robust monitoring mechanism within the existing PSC framework to ensure that, henceforth, a fully transparent and cost-effective process is adopted by the Operatorwhich gives assurance to the Government that costs have indeed been competitive.

8. <u>Review of DoC in respect of three discoveries, viz. D29, D30 and D31:</u> The Committee note that as required under PSC, the Operator submitted in February 2010 a DoC(Declaration of Commerciality) proposal for D29, D30, D31 and D34 discoveries for review by the MC and the DGH in June 2010 informed Operator that the discoveries were marginal and not viable at US$4.2/ mmbtu since the Modular Dynamic Test carried out by the operator did not provide individual testing rates to demonstrate sustainable production levels. The DGH, again, in October 2010 communicated to the operator that the DoC could not be reviewed. However, in November 2011, DoC in respect of D34 discovery was reviewed after the Operator submitted related additional test data/ information. But, in respect of D29, D30 and D31, DGH stated that commerciality of discoveries could not be evaluated in the absence of production tests which provide sustainable production levels from the reservoir as no appraisal wells were drilled in the pools of discovery wells to substantiate the production rates considered by the Operator. DGH felt that the profile generated without considering MDT/ (Drill Stem Test) DST data in the wells was not on a sound technical basis. In May 2012, the Operator again requested MC to complete review of DoC for D29, 30 and D31 and submitted a proposal in October- November 2012 to undertake DST in only one well out of the three discoveries and DGH while agreeing to the proposal asked

the Operator to submit a plan for surface flow test for other two discovery wells also. However, the Operator did not carry out the same and later argued that, as per PSC, a) the DST was not mandatory, b) the Contractor has the right to determine requirement for DST based on its technical judgment and c) it was not the only test . Subsequently, DGH, in April 2013, proposed that the area pertaining to these three discoveries be relinquished as the Operator could not keep a part of the Contract Area for an indefinitely long period in the garb of an incomplete DoC proposal. In October 2013, the matter was referred to CCEA(Cabinet Committee on Economic Affairs) for its information fully explaining the facts and circumstances of the case and the Contractor was allowed to retain 298 sq km. contract area as the matter was being considered. The Committee note from the reply of the Ministry that the issue was reopened for review in view of the petroleum potential of the discoveries in an energy starving country for an appropriate decision by competent authority in terms of the PSC provisions and the interest of energy security. The Committee further note from the reply of the MoPNG that the CCEA has, in April 2015, given relaxation for conducting DST by capping such test cost recovery upto US $ 15 m per test and , accordingly, the operator has now completed DST for D29 and D30 discoveries and has relinquished D31 discovery and has to submit revised DOC for D29 and D30 by 28th April 2016. The Committee are of the view that Government took around 5 years in taking a decision on the issue. The Committee observe that the long delays in clearances and operational decision making results in huge cost overruns and eventually affects the Government's share of PP. The Committee are of the view that energy starving country needs regular supply of the resources which is hindered by such delays. The Committee while noting that the CCEA has relaxed the provisions by providing that Operator should either relinquish or carry out DST and pay penalty for delays or develop the discoveries on his own in ringfenced manner are of the view that a comprehensive policy may be brought out allowing alternative tests for confirming commerciality of the discoveries to ensure that the policy does not get redundant with introduction of new technologies.

9. <u>Optimized Field Development Plan (OFDP) for four satellite discoveries:</u>The Committee note that Contractor in July 2008 submitted a Development Plan (DP) in respect of 9 Satellite Gas Discoveries (SGD) for approval of MC which was found non -viable at the gas price of US$4.2 per mmbtu. The Contractor submitted in December 2009, an Optimized Field Development Plan (OFDP) for four satellite discoveries. Initially, the OFDP was not techno-economically viable; however it was made marginally viable by devising different scenarios and changing assumptions e.g. exclusion of royalty as expenditure, variation in capex etc and was eventually approved by the DGH. The Committee note that MoPNG had directed DGH to engage a third party for validation of capex but no third party could be engaged and the MC approved OFDP without waiting for the decision of MoPNG in this regard. The Committee note that Audit had recommended that MoPNG may consider fixing norms/ criteria for working out techno-economic analysis of a FDP. The Ministry in its reply had submitted 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 and since techno economic evaluation is guided by the principle of economics and application of mind, setting separate norms may not be possible. However, the Ministry in their written replies has now submitted that the team constituted for framing the "Good International Petroleum Industries Practices" has identified the best practices being followed for all technical and commercial activities under the PSC and the report has been submitted for adoption and notification. The Committee while appreciating that the Good International Petroleum Industries Practices are being identified desire to be apprised of the practices as soon as they are notified and further desire the Ministry to ensure that decisions are taken by the MC after getting views from all the stakeholders, as in the instant case, 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. The Committee also desire that MoPNG seek explanation of the

representative of MoPNG i.e. Chairman of MC, and the representative of DGH in the MC who did not wait for MoPNG's decision.

<u>Change orders/ post contract modifications affected by the Contractor</u>

10. <u>Contract for Engineering, Procurement, Installation and Construction of offshore facilities</u>: The Committee note that the Operator awarded contact for Engineering, Procurement, Installation and Construction (EPIC) of offshore facilities for development of D1-D3 fields to M/s Allseas Marine Contractors S.A. (AMC) in October 2006 consisting of three milestones to be achieved by July 2008. However, AMC was not able to achieve the milestones and informed the Operator in June 2008 that various factors attributable to Operator, AMC and sub-contractors were preventing it from performing its obligations under the contract, rendering it inoperable both in delivery and contract administration. AMC asked the Operator to pay for the extra expenses to achieve the earliest possible First Gas date and also the additional expenses already incurred in the past months due to deviations in the suggested scheme. The Committee note that the Operator initially refuted the claims made by AMC asserting that the AMC should acknowledge and accept responsibility for its lack of performance, but, eventually after discussions with AMC submitted a proposal before the OC requesting it to grant some concessions demanded by the AMC. The Committee find that the OC gave concessions which included providing additional resources for expediting the works without any cost to AMC, substituting the subsea construction vessel by paying mobilization fee, additional diving spread free of cost, additional amount for delays not attributable to AMC, relaxation in levy of LD, incentive for achieving first gas by specified date and assistance and paying for resources for expediting jumper fabrication. As per Audit, Appendix C of PSC provides that " amounts paid with respect to non-fulfillment of contractual obligations are not recoverable and not allowable" and , therefore, should not be recoverable from the block. As per Operator, " ..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 have only led to the AMC halting work on the project and getting into prolonged litigation with the Operator." MoPNG in its reply has stated that the post vendor contractual agreements between the Operator and the vendor validly amended the original vendor-contract and the audit report did not point out any legally tenable ground for cost disallowance such as affiliated transactions to the undue advantage of Contractor, any incidence of fraud and costs not supported by payment evidences. Audit further observed that these concessions granted by the Operator were not in line with EPIC contract including provisions relating to change in contract price' The Committee after carefully considering the audit opinion and the replies of both Operator and Ministry are of the view that to ensure transparency in post vendor contractual agreements, in future, the Ministry should prescribe a threshold amount for the change orders above which the Operator should invariably approach it for clearance.

11. <u>Extension of Dry Docking life:</u> The Committee note that , in May 2007, Operator entered into an agreement with M/s Aker Contracting FP AS, Norway (ACFP/ vendor) for chartering of a Floating, Production, Storage and Offloading (FPSO) facility for ten years on lease rental basis for extraction, production, storage and offloading of oil & gas from MA oilfield, from the date of first production. However, within four months of signing the agreement, the Operator requested the vendor to extend the dry docking(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 and inspected) life of the FPSO from 10 to 15 years for a one -time compensation to the vendor. The Operator reasoned that the decision was taken to avoid interruption in production during the dry-dock period at the end of 10 years, additional costs due to increased scope of work, inflation, mob/ demob for dry-docking, potential loss of reserves due to uncertainty about revival of wells after closure and loss in value due to deferment of production. ." MoPNG in its reply has stated that the post vendor contractual agreements between the

Operator and the vendor validly amended the original vendor-contract and the audit report did not point out any legally tenable ground for cost disallowance such as affiliated transactions to the undue advantage of Contractor, any incidence of fraud and costs not supported by payment evidences. Audit had observed 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 GoIs share of PP and since the Operator has yet to renew the agreement after September 2018, it may not result in any expected benefit till the contract gets extension. The Committee are of the view that instead of asking for any legally tenable ground MoPNG should ensure that the benefits claimed by the Operator are materialized by monitoring the implementation of the post vendor contractual agreement in letter and spirit. The Committee are of the view that the additional costs incurred for extending the contract to 15 years should be allowed to the contractor only when the utilization of FPSO exceeds 10 year under the PSC.

12. <u>Increased cost for expediting date of first production of oil and gas:</u> As per Audit, at the time of issue of ' Request for Proposal' RFP for FPSO, one of the eligibility conditions insisted upon by the Operator was that the Date of First Production of Oil (DFPO) be on or before 15.2.2008 which was changed and the final agreement stipulated that it could be between 7-27.4.2008 but was subsequently extended to 30.9.2008 in October, 2007. In July 2008, the vendor communicated that the work and delivery dates could be expedited by putting in place measures having cost consequences which were agreed to by the Operator and included payment for mobilizing its commissioning team and one-time compensation on account of expediting deliveries and timely installations. Audit observed that , in April 2008, MC had approved the DFPO on or before June 2009 and , therefore, there was no necessity for expediting deliveries , as the vendor was entitled to lease rental for FPSO from DFPO, it was in his interest to achieve that at the earliest and the vendor had actually missed his deadlines and was already working on extensions. As per the Operator, the execution of all the

contracts were inter-linked and involved significant interfaces, delay in execution of one aspect could have had a cascading impact on the schedules resulting in far greater expenditures and that under the PSC, RIL had the right to make certain operational, technical and commercial decisions based on its best judgment and it was not appropriate to second-guess these judgments in hindsight. As per the Ministry, the post vendor contractual agreements between the Operator and the vendor validly amended the original vendor-contract and the audit report did not point out any legally tenable ground for cost disallowance such as affiliated transactions to the undue advantage of Contractor, any incidence of fraud and costs not supported by payment evidences. The Committee are of the view that though the Operator is the best judge of the operational and technical needs and decisions required therein , the commercial implications of such decisions directly affect the interests of the Government and the whole nation. The competitiveness of the transactions carried out by the Operator would ,therefore, always be open to public scrutiny. The Committee after considering the views of the C&AG, Operator and the Ministry opine that a cost-benefit analysis of the decision taken by the Operator to expedite the first gas date may be made before allowing the costs.

13. <u>Fabrication and installation of living quarters :</u> The Committee note that as per the agreement relating to functional requirements in FPSO, the general facilities / requirements for operations include air-conditioned living quarters with configuration of one bed, two beds and four beds cabins to accommodate 104 people and 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. However, extensive refurbishment and upgradation with modifications and re-design of the 64 existing living quarters was done on the request of the Operator which resulted in additional compensation to the vendor. The Operator explained that the personnel working offshore are subjected to hard life and harsh working conditions and upgraded and extensively refurbished living quarters would not only mitigate some of the

hardships but also improves productivity , safety and alertness. MoPNG in its reply has stated that the post vendor contractual agreements between the Operator and the vendor validly amended the original vendor-contract and the audit report did not point out any legally tenable ground for cost disallowance such as affiliated transactions to the undue advantage of Contractor, any incidence of fraud and costs not supported by payment evidences. Audit observed that it was the responsibility of the vendor to depute personnel on the FPSO and the existing contract with additional 40 quarters had met the requirements of the FPSO charter contract and also the harsh working conditions were always known and could have been finalised at the time of procuring FPSO. The Committee also note that the development plan for the MA field included the cost of purchase of FPSO but the Operator chartered the FPSO. The refurbishment was also guided by the option of purchase at any time during the charter period which has not been exercised so far. The Committee observe that refurbishments could have been negotiated at the initial stages as the harsh conditions and existing layouts were available at that time. The Committee, however, are surprised to note that the Ministry, in its presentation to them, has bunched all the expenditure related issues and given a single reply to all of them without any issue related reasoning, clarification or explanation. The Committee, therefore, desire to be apprised of the MoPNG's reply on the need, necessity and level of the refurbishment undertaken at the request of the Operator.

14. <u>Construction of Onshore Terminal:</u> The Committee note that the contract for construction of Onshore terminal (OT) was awarded on cost-plus basis to L&T Ltd. (vendor) and as per original contractual provisions " no compensation is payable to the vendor on account of the Plant & Equipment (P&E) provided by the Operator either owned or hired in the case of vendor being unable to mobilize the P&E. However, the said clause was amended to exclude cranes from its ambit and resultantly, the Operator, in addition to incurring expenditure on hiring of these cranes, had to pay top up compensation on them like other P&E supplied by L&T. The Operator in its reply submitted that since the suppliers of the crane

were reluctant to accept the contract through L&T and due to shortage of such cranes in the market, it had to hire the cranes directly and as these cranes require a lot of handling by the L&T, the Operator was justified in the payment of compensation to the vendor. Audit had observed that the scarcity of the cranes in the market or reluctance of suppliers to deal with L&T could not be a justification for amending the contract and pay additional amount to L&T as the principle underlying such transactions was clear in the respect that it had already provided that no compensation is payable to the vendor in case of vendor being unable to mobilize P&E and, therefore, the cost recovery may be disallowed. MoPNG in its reply has stated that the post vendor contractual agreements between the Operator and the vendor validly amended the original vendor-contract and the audit report did not point out any legally tenable ground for cost disallowance such as affiliated transactions to the undue advantage of Contractor, any incidence of fraud and costs not supported by payment evidences. The Committee desire that Ministry look into the contract to see whether such amendments can validly be made which change the basic principles and whether such mark-ups are usually charged by the vendors in similar contracts and apprise the Committee thereof.

15. <u>Payment of compensation on Free Issue Materials:</u> The Committee also note that 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). These contracts contained provisions for FIMs (Free Issue Materials) which were to be arranged by the Operator at its own cost and , therefore, different clauses of the contracts excluded various FIMs supplied by the Operator from the purview of payment of compensation to the vendor. But, a percentage of the value of FIMs of some categories supplied by the Operator was included in the payment of compensation to the vendor. The Operator submitted 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 and that these

FIMs were not capital items and were related to day to day construction materials which require project execution skills, planning and co-ordination to meet construction schedule and if procurement were kept in the Contractor's scope directly then this would have resulted in double taxation with respect to VAT and Service Tax and increased compensation on this account. MoPNG in its reply has stated that the post vendor contractual agreements between the Operator and the vendor validly amended the original vendor-contract and the audit report did not point out any legally tenable ground for cost disallowance such as affiliated transactions to the undue advantage of Contractor, any incidence of fraud and costs not supported by payment evidences. The Committee are of the view that the Ministry should call for a comparative statement of costs incurred due to such provisioning and costs incurred if the materials were directly procured by the vendor before taking a decision on the allowance of the costs.

16. Classification of Start-up and Production Bonuses as part of recoverable costs As per Audit, during the period 2008-09 to 2009-10, the Operator charged long term bonus(LTB), productivity linked incentives(PLI), start-up bonus and production bonus paid to its employees in proportion to number of hours they were engaged in the work relating to this block. The Operator has been paying LTB as a retention bonus and PLI to its E&P employees. In addition the start-up and production bonuses were given to the E&P employees on the occasion of starting first gas production. Audit had stated that PSC provides for payment of bonus to those assigned personnel who are directly and necessarily engaged in the conduct of the petroleum operations and 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 and includes salaries, wages and other costs which are as per the personnel policy and are of a regular nature. Audit had observed that since start-up and production bonus are one-time and of an ad-hoc nature, these should not be paid from the revenue earned from the sale of gas. According to Operator, the PSC nowhere stipulates such restrictions and the opinion of the audit is not in

line with the provisions of the PSC as it is clear that the cost of employee benefits, including bonus are eligible for cost recovery and the start-up and production bonus was paid to employees as a performance bonus for completion of activities directly concerned with the project to improve employees morale and productivity. Audit further stated that Operator has been paying LTB as a retention bonus and PLI to its E&P employees for improving morale and productivity and retaining the experienced employees. MoPNG in its reply has stated that the post vendor contractual agreements between the Operator and the vendor validly amended the original vendor-contract and the audit report did not point out any legally tenable ground for cost disallowance such as affiliated transactions to the undue advantage of Contractor, any incidence of fraud and costs not supported by payment evidences. The Committee are of the view that as the disagreement between the parties involves correct interpretation of the provisions of PSC, MoPNG may seek the views of Ministry of Law thereon and apprise the Committee thereof.

17. <u>Piece-meal hiring of drilling rig:</u> The Committee note that the Operator awarded charter hire of an off-shore deep water drilling rig to M/s Transocean Offshore International Ventures Limited (Transocean/vendor) in April 2005 for 24 months. In December 2005, seven months after awarding first contract, the Operator initiated the tendering process for charter hiring beyond 2007 as the Operator observed that availability of Deepwater drilling rigs had become scarce. The second contract was again awarded to Transocean for 36 month period commencing from August, 2008. Audit observed that despite having adequate drilling prospect and keeping in view the poor response received from the vendors for provisioning of the rigs , the Operator did not find it prudent to consider the option of long-term hiring and availing the firm rate advantage of such long term hiring which resulted in additional expenditure. The Operator submitted that approval for laying of pipelines to evacuate & market gas was delayed by the MoPNG by 17 months which delayed the project and considering the aforesaid uncertainty in execution of IDP, there was no rationale for

contractor to commit drilling rigs on the basis of IDP . MoPNG in its action taken notes stated that " this can be at best considered as inadequate appreciation and lack of proper planning by the Contractors. The Contractors may not be aware of future behaviour of market for hiring of services. Audit may reconsider this disallowance". MoPNG in its latest reply has stated that the post vendor contractual agreements between the Operator and the vendor validly amended the original vendor-contract and the audit report did not point out any legally tenable ground for cost disallowance such as affiliated transactions to the undue advantage of Contractor, any incidence of fraud and costs not supported by payment evidences. The Committee after taking into consideration the Audit observation, the submission of the Operator and the replies of the Ministry are of the view that costs cannot be disallowed as both the contracts were awarded on the basis of competitive tendering process in accordance with procedure prescribed in the PSC , moreover, whether additional costs have actually been incurred by the Operator and the extent of any such extra expenditure cannot be assumed in absence of per day rates that would have been quoted by the vendor for a five year contract instead of the two year contract that was awarded in 2005. However, the Committee do not appreciate the Ministry's passive role in such high value contracts and reiterate as recommended by them in the preceding paragraphs that a threshold amount for the orders/ contracts may be prescribed above which the Operator should invariably approach the Ministry for clearance.

18. <u>Bonus paid for time saved during rig movement:</u> The Committee further note from the observation of the Audit that the Operator paid M/s Transocean bonus for time saved during the rig movement between wells with hanging Blow Out Preventor (BWP) which were not covered under the terms and conditions of the contracts and hence should be disallowed. According to the Operator, the vendor was entitled to performance incentive in accordance with the provision of the contracts for completing the wells ahead of the target number of days and the incentive scheme was to be mutually agreed and payment modalities were to be separately worked out as per the contracts. But Audit contended that the

incentive should have been accordingly paid for completion of wells rather than a single activity of rig movement. According to MoPNG, the amount involved was actual expenditure incurred in petroleum operations in a transaction not reported by audit to be an affiliate transaction or transaction unduly benefitting the Operator/ Contractor. The Committee are of the view that as the disagreement between the parties involves correct interpretation of the provisions of PSC, MoPNG may seek the views of Ministry of Law thereon and apprise the Committee thereof.

Panna-Mukta and Mid & South Tapti Fields

The Panna-Mukta (primarily an oil field) and Mid & South Tapti (gas field) are shallow water fields located in the offshore Bombay basin, were initially discovered and operated by ONGC. Following the 1992 offering of small and medium sized oil and gas fields for development, GoI awarded (February 1994) the Panna-Mukta and Mid & South Tapti contract areas, which were discovered by ONGC, to a consortium comprising of ONGC (40 *per cent*), RIL (30 *per cent*) and Enron Oil & Gas India Ltd-ENRON (30 *per cent*) (together called Contractor) under a production sharing arrangement. The PSC was signed in December 1994 between the GoI and the Contractor. The Contractor formed an unincorporated joint venture (JV) called PMT JV. In February 2002, British Gas Exploration and Production India Limited (BGEPIL) acquired ENRON's 30 *per cent* stake in the JV and became a party to the PSC. Presently, the field is jointly operated by ONGC, RIL and BGEPIL.

The C&AG in their Report No. 19 of 2011-12 have scrutinised records of the Ministry of Petroleum and Natural Gas (MoPNG) and the Directorate General of Hydrocarbons (DGH) in respect of a sample of 20 PSCs covering the period from 2003-04 to 2007-08, and also conducted supplementary scrutiny of records of the operators of 4 blocks/fields including Panna-Mukta and Mid & South Tapti covering the two year period 2006-07 and 2007-08.

The C&AG in their Report No. 24 of 2014 have covered the four years period from 2008-09 to 2011-12 and contains the results of the Performance Audit on 'Hydrocarbon Production Sharing Contracts' at the Ministry of Petroleum and Natural Gas (MoPNG) and the Directorate General of Hydrocarbons (DGH) with respect to blocks/fields including that of Panna-Mukta and Mid & South Tapti.

ONGC in their presentation have stated that the Tapti field is at the verge of closure due to cessation of production. Hence, no further development activity can be undertaken by PMT JV in this field.

The following recommendations have been made based on the observations of the C&AG and the submissions of the Ministry of Petroleum and Natural Gas (MoPNG) and the Operator i.e. Oil and Natural Gas Corporation Limited (ONGC):-

Non-Signing Of Crude Oil Sales Agreement (COSA)

19. The Committee note that despite elapse of more than 21 years (since 1994), COSA has not been formalized by the Panna-Mukta JV with IOCL (GoI nominee) due to non-resolution of issues such as delivery point, storage charges, dead freight, voyage costs/ losses, terminal charges, measurement conversion table, dollar rupee exchange rate, lay time in monsoon and delayed payments and interests thereon. The non-signing of COSA for Panna-Mukta PSC has previously also been commented and highlighted in C&AG audit reports of 1996, 2005 and 2011. Thus, non-signing of COSA led to non-resolution of storage and voyage expenses and are shown as recoverable by PMT JV from GoI/GoI's nominee i.e., IOCL. The Ministry and ONGC while deposing before the Committee and in their written submission have stated that various correspondences and meetings were held between PMT JV & IOCL since the commencement of crude oil sales in 1994-95. However, the issues could not be resolved. Subsequently, in 2014 a Task Force was constituted which has so far held seven meetings, the last one being on 08.03.2016. As per the Minutes of the 5th meeting of Task Force held on

20.04.2015, the settlement of issue related to sale of crude oil for Panna – Mukta have agreed on along with agreement that the PMT JV shall prepare a draft settlement agreement on the basis of these signed minutes within 15 days. The PMT JV were to share a draft of the more detailed COSA within 90 days from the date of execution of the Settlement Agreement. The Parties have agreed that post signing of the settlement agreement and until such time that the COSA is executed, the settlement agreement shall be binding agreement between the Parties and shall be basis on which all future sale and purchase of crude oil from Panna-Mukta area occurs. The Committee are shocked to find that even though 21 long years have passed, the PMT JV could not resolve the pending issues resulting in non-signing of COSA and loss to the exchequer. This shows the non-serious approach of the PMT JV as well as IOCL. The Committee also desire the Ministry of Petroleum and Natural Gas to look into the reasons for inordinate and inexplicable delays and failure of the monitoring mechanism of the Ministry and fix responsibility by taking appropriate punitive action against the concerned officials. Accordingly, the Committee may be apprised on the matter within four months of the presentation of the Report.

Cost Recovery of Unconsumed Production Inventory:

20. The Committee note that Section 3.1.8 of the PSC stipulates that material and equipment held in inventory shall be charged to the accounts only when such material is removed from inventory and used in Petroleum Operations. However, contrary to the PSC provision, the contractor has charged production inventory to cost recovery on date of purchase irrespective of its actual usage in Petroleum Operations. It was also seen that some inventory was not used for more than four years. The cost recovery made by the contractor without actual usage for petroleum operations had adversely affected GoI share of PP. The PMT JV's contention that such production consumable items are maintained at reasonable levels so as to avoid any production downtime due to non-availability of such items was contested by the audit. Audit further pointed that PMT JV may ensure that production inventory is charged to accounts only when such material

is removed from inventory and used in petroleum operations as provided in the PSC. The Committee while deprecating the PMTJV's violation of provisions of a mutually agreed PSC, desire that as agreed to by the Ministry, year wise inventory included by Operator in the contract cost should be corrected in the account for subsequent years.

Award of Contract for Installation of Platforms

21. The Committee note that PMT JV entered into a settlement agreement with M/s Swiber for relocating the PK and SWP platforms on a nomination basis in March 2010 rather than on a tender basis as mandated in the PSC. The actual cost for transportation and installation far exceeded the estimates. It was astonishing to find that against the estimated cost, the actual contracted price was more than double. The PMT JV's contention that the estimate was merely on early estimate of likely cost was objected to by the Audit. The Audit pointed out that the estimates for PL project had been prepared in August 2008 and the contract was awarded merely a month later in September 2008 to M/s Swiber for SWP and PK platforms based on quotes received in the tender for SWP and PK platform. Audit, therefore, concluded that the cost incurred for the transportation and installation under PL project was comparatively very high vis-a-vis the original estimates. The PMT JV in their explanation submitted that they engaged Swiber to undertake the modifications to minimize the time for award of contract as the material was under care of Swiber and there was concern that there might be a dispute under the existing contract with Swiber regarding incomplete scope and also there was no desire to incur extensive storage costs from Swiber.

The Committee are not satisfied with the MoPNG's observation that audit exception has been notified to the contractor. The Committee while deprecating the lackadaisical attitude of the MoPNG recommend that the Ministry should look into the issue of award of contract to M/s Swiber on settlement basis rather than on tender basis as mandated in the PSC and also see if it has adversely affected the GoI's share.

<u>Delay in Water Injection (WI) Project in Panna Field Resulting in Declining Production</u>

22. The Committee are concerned to note that delay in implementing Water Injection (WI) in Panna field has resulted in decline in production. The DGH as well as the JV were aware of the continuous fall in reservoir pressure and consequent decline in production from Panna field from 2003 onwards (10-12 per cent in 2003 to 12-15 per cent in 2007-08 and to 18-20 percent in 2010-11). Keeping in view the decline in production the PMT JV submitted a 'Panna B Zone Water Injection Pre-Feasibility Report' in 2011 and subsequently requested for extension of PSC term till economic life of the field. The Committee are shocked to know that DGH in March 2012 in response to the JV have stated that pressure maintenance should have been started as soon as it was evident that the reservoir pressure was falling below saturation point and that the Operators should have proposed WI in early 2000 if they were serious about good operational standards and reservoir management. The Committee further note that DGH is yet to approve the feasibility report and as on date there is no further progress on the decision on the PSC extension. The fact that Pre-Feasibility study report submitted by PMT JV in September 2011 for expeditious implementation of WI scheme and DGH taking six months (October 2011 to March 2012) to take a decision and communicate to the JV, puts question on the DGH role resulting in delay in Water Injection project and consequent decline in production from Panna field. The Committee desire that the Ministry to impress upon the DGH to complete the examination and subsequent implementation of the Report along with other measures to check declining trend in the production from Panna field. The Committee also desire the Ministry to take view on extension of PSC at the earliest.

<u>Sale of Gas in Contravention to MoPNG'S Directives</u>

23. The Committee observe that ONGC ignored MoPNG directives of March 2006 and entered into a long term contract for 12 years and signed GSPA in June

2006 with M/s Torrent Power Limited (TPL) for supply of 0.9 mmscmd of gas at the rate of US$ 4.75 / mmbtu with a provision to review the price after expiry of 3 years from the date of first supply. At the same time, contrary to GoI decision the other two partners, RIL and BGEPIL, also sold gas at the rate of US$5.58 per mmbtu (i.e. higher by US$0.01 per mmbtu of revised PSC price of Tapti field). Supply to TPL commenced from 30 May 2008 and continued at the lower rate of US$ 4.75 per mmbtu till May 2011 and it was made at PSC price only from June 2011. The gas sold to TPL was at a price lower than the price prescribed in the PSC (Panna-Mukta revised PSC price of US$ 5.73 / mmbtu and Tapti revised PSC price of US$ 5.57 / mmbtu). Further, the Committee observe that ONGC also did not reduce the sale of gas proportionate to the decline in production in the Tapti and Panna-Mukta fields during the year 2008-09 to 2011-12 and on the contrary sold more gas to TPL during 2009-10 to 2010-11 vis-a-vis 2008-09. The Ministry have submitted, since GAIL was unable to lift gas at a higher PSC formula based price, ONGC entered into agreement in June 2006 with TPL. Further, the Ministry have stated that the notional revenue loss was on account of the fact that the PSC formula based price was above the prevailing market price and in the absence of GAIL lifting the entire gas quantity, the Ministry permitted the constituents of JV to sell gas at rates ranging from US$ 3.86 to US$ 5.58. The Committee are in agreement with Audit that the argument of ONGC on Article VIII of Tripartite Agreement i.e. the GAIL was fully responsible for the performance of the existing contract is not tenable as ONGC was selling its share of gas to TPL below the PSC price and it was obligatory on the part of ONGC to periodically inform GAIL about the drop in level of production for making proportionate reduction in supply to TPL. The Committee are of the firm view that the Ministry, should have been proactive in monitoring the dispensation of additional gas production (over and above 10.8 mmdcmd) by the PMT JV when it had issued clear instructions. The Committee strongly deprecate the casual approach of the Ministry in protecting the interest of the government and desire that the failure of ONGC first to find a buyer at PSC price and later on to curtail on pro rata basis the supply of gas to TPL be enquired into and responsibility be fixed. The

Committee also desire the Ministry to look into whether the competitive prices were not obtained by the other two JV partners while supplying the gas to their affiliates.

Delay in Non-Fixation of Transportation Losses of Condensate

24. The Committee note that although the PSC for Mid and South Tapti was silent on the disposal of condensate, i.e. whether it is gas or crude oil, PMT JV was treating the condensate as gas till December 2005. Further, the transportation and processing of PMT gas was undertaken by ONGC through its South Bassein-Hazira offshore trunk pipeline and onshore Hazira facilities respectively and was governed by a Settlement Agreement of December 2005 between ONGC and PMT JV. In the Settlement Agreement, the condensate transportation losses from the Tapti delivery point to ONGC's Hazira Plant were to be determined by a Condensate Expert to be jointly appointed by ONGC and PMT JV. Pending determination of such losses, it was agreed to treat the Tapti condensate losses provisionally as 'zero'. The Audit further noticed that while ONGC was considering internally 6 per cent as transportation and processing loss from condensate, the PMT JV was considering the loss as 'zero' from 2005. The ONGC's submission that with the appointment and submission of the report by the Condensate Expert (M/s Worley Parsons Consulting) both parties have agreed to consider a shrinkage of 3.6 per cent. Further, the proposed amount payable to ONGC at US$7.943 million has to be adjusted against pending PMT JV invoices of US$13.08 million upto 30.09.2015. In view of the differential consideration of condensate losses ranging from 'zero' (PMT JV) to 6 percent (ONGC) and subsequent calculation of shrinkage as 3.6 percent (Condensate Expert) clearly shows that the validity of observation made by the Audit. The Committee are of the view that the issue of fixation of transportation losses of condensate should not have been kept pending for so long and therefore desire that the Ministry may take appropriate steps to look into the non-serious attitude of the PMT JV for not appointing the Expert although the Settlement Agreement was reached in 2005. The Committee further desires that all issues related to

approvals and final settlement of the matter may be pursued expeditiously and the Committee apprised accordingly.

Matters Related to Arbitration

25. The Committee find that the two JV partners namely RIL and BGEPIL served Arbitration notices to GoI and have raised claims pertaining to i) Cost Recovery provisions under Panna-Mukta and Tapti PSC, ii) Calculation of IM, iii) Amount of royalty payable under PMT PSC, iv) Amount of cess payable by Contractor to GoI, v) Amount of service tax payable under PSC, and vi) Meaning and effect of Accounting and Audit provisions. It has been further noted that on the directions of the Ministry, ONGC has not participated in the Arbitration and ONGC has agreed that they shall abide by the arbitral award. The Committee further note that majority of the problems in the PSCs over the NELP regime are related to cost recovery. While appreciating the Government's move for doing away with micro-management or day-to-day operations and moving from profit sharing towards the revenue sharing model, the Committee hope that this will help the prospective PSCs for lesser disputes and thereby early settlement of issues between the parties. The Committee desire that an effective mechanism should be developed for speedy resolution of cases so that the aggrieved parties need not spend long years for redressal of their grievances.

RJ-ON-90/1 Block:

RJ-ON-90/1 Block ,an onland block (mainly in Rajasthan, with a small portion in Gujarat), was awarded in Round- IV of the Pre-NELP exploration rounds in May 1995 to Shell India Production And Development(BV) (SIPD) which, subsequently, transferred its Participating Interest(PI) to Cairn Energy India Limited and Cairn Energy Hydrocarbons Limited (collectively termed as Cairn Energy) in three phases during September 1998 to June 2003. ONGC was the licensee and was responsible for obtaining the Petroleum Exploration License (PEL) and Mining Lease(ML) and had the right to take a PI upto a maximum of 30% in each Development Area (DA). ONGC acquired 30% PI in two Development Areas, DA-1 and DA-2, while its decision to acquire 30% in DA-3 was under

reference to MoPNG. The major observations of Audit regarding RJ-ON Block are as under:

- **a) Declaration of fresh discoveries during the appraisal/ development phases within delineated discovery/ development areas amounted to irregular extension of exploration activities.**
- **b) Non- compliance of PSC provisions for notification of potential commercial interest, appraisal programme, submission of Field Development Plans etc.**
- **c) Adjustment of costs incurred towards shipping of crude to MRPL and RIL beyond delivery point resulted in short payment of Profit Petroleum to GoI.**
- **d) MRPL's inability to take RJ crude citing its characteristics (highly viscous with huge pour point and residue) and refining capacity adversely affected production and evacuation of crude from the block.**
- **e) Delay in submission of Work Programme and Budget.**

26. <u>Delay in submission of WP&B:</u> Audit observed that there were delays in submission of annual WP&B in each of the years from 2008-09 to 2011-12 on the part of OC ranging from 91-111 days and on the part of MC ranging from 70-239 days which meant that the WP&B for a financial year was actually approved after the beginning of the financial year and, shockingly, the WP&B for 2011-12 was submitted to the MC in April 2011 and approved by MC in December 2011. The Committee note from the reply of the Operator that "..annual WP&B merely reflect phasing of the expenditure on year to year basis …what was more critical was the project sanction which existed by means of MC approved FDPs.." and, further, from the reply of the MoPNG that the "PSC provides that the Contractor should submit the annual work programme and budget to the MC by 31st December of the previous year. Though there is no time limit for grant of approval by the MC, presumably the MC has three months (90) days for approval of the annual work programme & Budget before the year commences. With this background, the time taken by MC for approval of the budget is not found to be materially different and the PSC timelines were generally adhered to". The Committee are shocked to note that a Ministry of Government of India that is well versed with the budgeting

process and its benefits is undermining its importance. The Committee are of the view that it is obvious, the budgets are to be approved before the onset of the financial year, hence, there are no timelines prescribed in the PSC. The Committee also do not approve the Operator's contention that budgets merely reflect phasing of expenditure on year to year basis and observe that besides estimating, as realistically as possible, the cost to be incurred in the ensuing year, they provide a means to monitor how closely the actual progress toward achieving the objectives is being made relative to the proposed budget. The Committee while appreciating that the WP&B for 2015-16 was approved by MC before 31.3.2015 desire that the same practice be followed every year as the WP&B authorizes a particular activity within the approved budget.

27. Adjustment of Shipping Cost beyond delivery point: As per PSC, the Contractor would be responsible for all costs prior to the delivery point (DP) and the GoI or its nominee would be responsible for all costs beyond the delivery point and as an interim arrangement, the GoI had allowed delivery point at Kandla Port for transporting crude to HPCL & MRPL. The Committee note that as HPCL did not take any crude against its allocation and the Operator transported crude from October, 2009 to June 2010 to MRPL and RIL through the delivery point at Kandla and adjusted the expenditure (for oil supply beyond the DP towards shipping of crude to MRPL & RIL) against the revenue which resulted in short payment of Profit Petroleum to GoI. As per the Operator, since HPCL did not eventually buy crude oil and MRPL refused to lift the crude oil from Kandla Port, sales to RIL and MRPL were made through marine vessels and the costs so incurred were charged from the revenue as per Artcle 19.3 of PSC which provides that in case of Arm's length sales, the delivery point shall be the outer flange of the export terminal or the customer's facility in India or as the case may be. The Committee, however, note from the reply of the Ministry that the Contractor was advised by DGH in August 2012 disallowing cost recovery followed by a reminder in January 2014. The Ministry has again in March - April 2016 reiterated that "the Contractor has been advised disallowance of cost and

differential profit petroleum will be collected". The Committee are not able to comprehend as to why after lapse of around 4 years Ministry has not been able to collect the differential profit petroleum when the C&AG had quantified the costs in 2012 itself. The Committee desire that the differential profit petroleum may be collected at the earliest and the Committee apprised thereof.

28. <u>Inability of Government Nominee to lift crude:</u> According to Audit, as per Article 18.2 of PSC, the GoI or its nominee is under obligation to purchase the entire crude from the contract area and, accordingly, GoI designated MRPL as its nominee for RJ crude as ONGC and HPCL both had confirmed their ability to process the entire crude indicating that a pipeline would be laid from Barmer to Mundra port for taking the crude to their existing refineries viz. MRPL and HPCL. However, MRPL informed GoI that it could not take full allocation because of peculiar characteristics of RJ crude which resulted in nomination of multiple refineries by GoI for purchasing the crude; shifting of DP from Barmer to Salaya to Bhogat; and delaying of commencement of production from Q4 2007 to H2 2009. GoI approved in April 2008 shifting of delivery point from Barmer to Salaya, a location suitable for nominated refineries, but in December 2008, when the work had already started, the Operator requested for shifting it to Bhogat in view of ecological considerations and the pipeline from Barmer to Salaya was completed after a delay of 10 months in May 2010 and from Salaya to Bhogat scheduled to be completed in Q22010 was completed in June 2014. The Committee note that the delays resulted in rescheduling of drilling of wells and sale of crude through tankers which caused the controlled/ moderated production during the delayed period. Further, the GoI nominated refineries could not lift their allocated crude as MRPL discontinued its off-take till the installation of its Coker unit, HPCL did not lift any crude and IOCL had confirmed uplifting subject to commercial viability. Two spur lines built to facilitate delivery of crude to IOCL also remained underutilized as IOCL did not lift its full allocation. The Committee note that the inability of the refineries nominated by the GoI to lift RJ crude led to various delays and had huge cost implications. The Committee feel that the Ministry

should have been extra cautious while nominating other refineries once MRPL failed to lift the allocated crude despite confirmation by the ONGC at the beginning. The Committee are also shocked to note that the Ministry only followed the Operator and its advice and did not take adequate measures before sanctioning the pipeline from Barmer to Salaya as ecological clearances should have been insisted upon by the Ministry itself before sanctioning the first pipeline. Also, since IOCL had only agreed to lift crude subject to commercial viability, the Ministry should have undertaken a cost-benefit analysis before approving the two spur lines for IOCL. The Committee while observing that the lackadaisical approach of the Ministry and unprofessional attitude of the PSUs like ONGC , HPCL etc. led to delays and cost overruns which adversely affected the GoI share of Profit Petroleum and expect the Ministry to be pro-active and more professional in its approach in future.

29. <u>Pricing of RJ crude:</u> As per PSC, the calculation, the basis of calculation and the price of crude oil determined would be subject to agreement before it was finally determined and pending final determination, the price determined by the Contractor would be used. Since the price formula for working out the price is yet to be agreed by the MoPNG, the term sheets executed by the Operator with the private operator refineries were based on agreed price with no provision of revision from retrospective effect. MoPNG in June 2010 while informing the Operator that the position taken by private refineries with regard to revision of price was not acceptable and advised that sales made to these refineries be on provisional prices until final decision was arrived at by the GoI. The Committee note the contention of the Operator that basic pricing formula agreed upon with the IOCL is being used with the private refiners also and that formula was finalized with IOCL at arm's length. MoPNG in their reply have stated that PSC provides Government intervention when price is not at arms' length. The Committee find that Ministry has taken contradictory stands, firstly, it informed the Operator that the price charged was to be provisional and that the sales to the domestic private refineries were not to be construed as arms' length sales

however, in their presentation to the Committee it stated that Government intervention was not required. The Committee take serious view of the misleading responses given by the Ministry and desire that since the pricing of crude requires interpretation of the PSC, opinion of Ministry of Law may be sought and the Committee apprised thereof.

30. Award of contracts beyond PSC provisions: The Committee note that Audit, while reviewing 41 contracts, in respect of which payment was made during the years 2006-07 and 2007-08, found that 3 contracts were awarded on nomination or on single financial bid basis, 1 was awarded without assessing reasonability of rates and in 2 cases, extensions beyond contractual provisions were allowed without availing economies of scale. The Operator in its reply stated that the tendering process is resorted to by the Operator, however, approval for award is endorsed by the OC and during this period initial phase of field development was in progress with efforts to commence early production and the OC endorsed contracts in the best interest of the Contractor and also, in some cases only one bidder was technically qualified and some contracts were extended in the operational interest. MoPNG stated that OC consisting of members from ONGC and Cairn Energy monitors the award of procurement contracts and the interests of the Government are well protected by ONGC as Government nominee and licensee in the consortium. Audit, however, pointed out that in most of the procurement cases, ONGC approval for award proposal to the OC came much after placement of Letter of Awards by the Operator. The Committee while noting the presence of ONGC as Government nominee in OC find that ONGC is only ratifying contracts and not involved actively while awarding the contracts. The Committee, therefore, desire that, henceforth, ONGC be more resolute in its role as the protector of Government's interest and any deviation from the provisions of the PSC may be brought into the notice of MoPNG invariably.

31. Delay in finalizing optimization concept: The Committee note that an optimization concept for Bhagyam field was presented to MC in August 2010 to

which the final approval of MC was communicated in December 2010 which resulted in delayed commencement of the activities. The Operator reasoned that after MC review of the proposal, substantial deliberation took place on the concept optimization and the minutes were got signed by circulation. MoPNG in their reply stated that the MC first deliberated on the concept in July 2010 and in October 2010 passed the resolution and it took two more months for all the representatives to sign the resolution. The Committee also note that due to delay in execution of the activities, the budget for the year also remained under utilized. The Committee observe that the MC took unduly long time i.e. four months in approving the proposal and the lackadaisical approach eventually affected the commencement of activities. The Committee are of the view that delays invariably lead to cost overruns which ultimately adversely impacts the Government's share of profit petroleum. The Committee desire that a time frame may be prescribed for signing of such resolutions of the MC and the Committee be apprised thereof.

NEW DELHI;	**PROF. K.V.THOMAS**
26th April, 2016	**Chairperson,**
6 Vaisakha 1938 (Saka)	**Public Accounts Committee.**