Report of the
Comptroller and Auditor General of India
on
Utilisation of Rigs in
Oil and Natural Gas Corporation Limited

Union Government (Commercial)
Ministry of Petroleum & Natural Gas
No. 39 of 2015
(Performance Audit)

Index

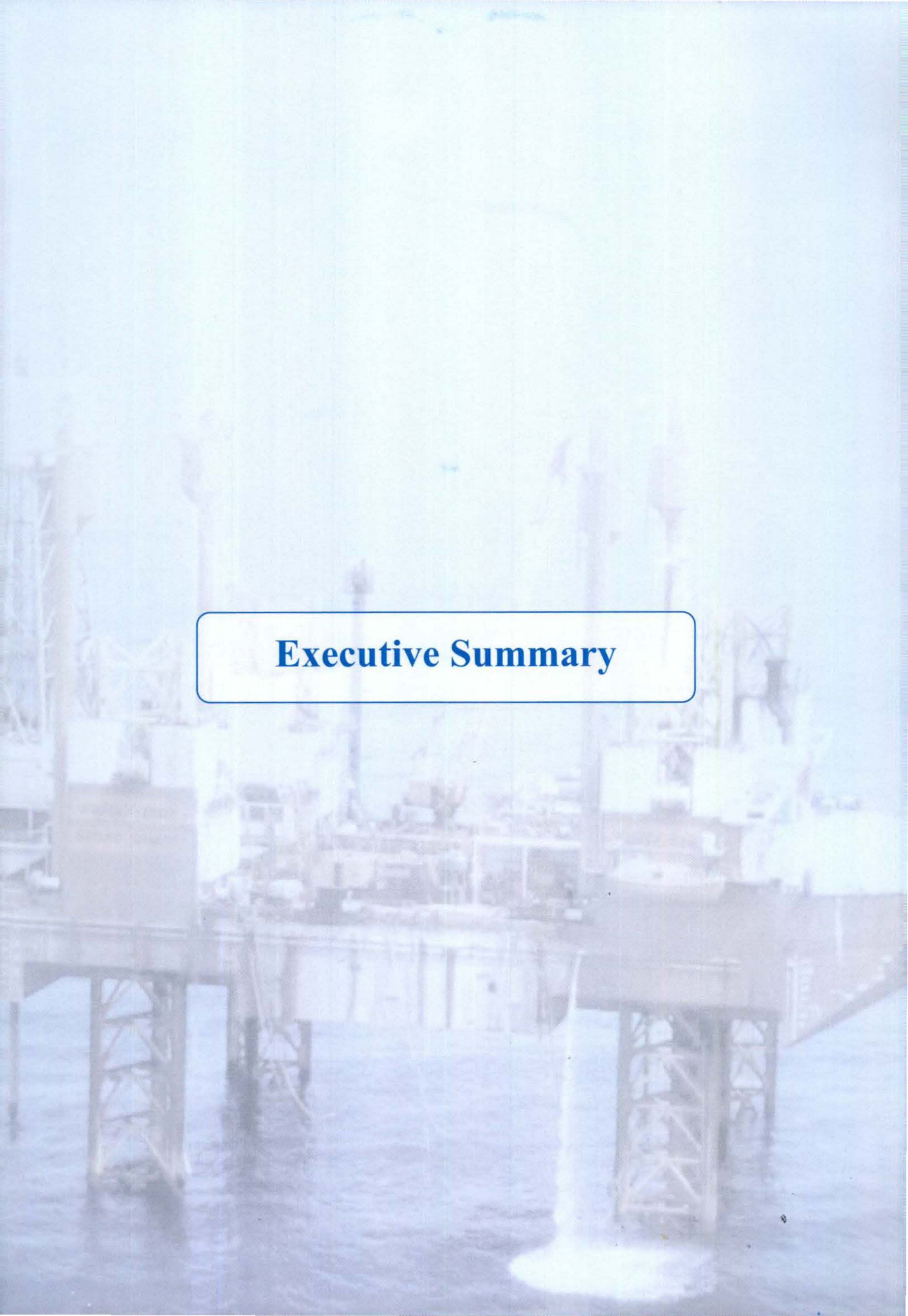
PREFACE

This Performance Audit Report has been prepared in accordance with the Performance Audit Guidelines and the Regulations on Audit and Accounts, 2007 of the Comptroller and Auditor General of India.

Oil and Natural Gas Corporation Limited (ONGC) is engaged in exploration, production and sale of crude oil and natural gas in both onland and offshore areas. Drilling operations constitute the single most significant activity of the Company accounting for over 50 *per cent* of the expenditure during 2010-14. The management of rig operations employed for drilling, thus, is of prime importance.

This report contains the results of the Performance Audit on Utilisation of Rigs in ONGC. The period from 2010-11 to 2013-14 has been covered in the report. The report is based on scrutiny of documents/records regarding planning, hiring, deployment and maintenance of rigs in ONGC.

Audit wishes to acknowledge the cooperation and assistance extended by the Ministry of Petroleum and Natural Gas (MOPNG) and the ONGC Management in the conduct of this performance audit.



Executive Summary

Executive Summary

Drilling activities are key to hydrocarbon production and reserve accretion and constitute the single most significant operation of an upstream oil exploration company, both financially and operationally. A performance audit of utilisation of rigs of Oil and Natural Gas Corporation Limited (ONGC - hereinafter referred to as the Company) was conducted to obtain reasonable assurance that the Company had planned, hired, deployed, utilised and maintained rigs in an efficient and effective manner. The period from 2010-11 to 2013-14 has been covered in the report. Significant audit findings are listed below:

Planning of Rigs

The Rig Requirement Plan (RRP) which estimates the offshore rigs required by the Company in the forthcoming five-year period to meet its planned drilling activities was prepared essentially on the basis of past experience of rig utilisation. This included idling of rigs in the past, bulk of which was controllable by the Company, for example, 86.26 to 93.89 *per cent* of the total non-productive time (NPT) in Western Offshore, where maximum rigs were deployed, were on account of controllable factors. The RRPs, thus, had in-built inefficiency. No RRP was prepared for onland areas. The Company also prepares annual Rig Deployment Plans (RDPs) for deployment of rigs. The annual RDPs (2010-14) provided additional rig days compared to the RRPs and, thus, included a margin for higher degree of inefficiency.

(Paragraphs 3.1 and 3.3)

There was no uniformity in the manner of preparation of annual RDPs among the Assets and Basins. Benchmark norms have been prescribed by the Company for a few onland Assets in 2011. However, even for these Assets, the benchmarks had not been uniformly adopted. It was noticed that plan for Ankleshwar, Ahmedabad and Mehsana Assets had days in excess of benchmark norms, 2011. Of the balance onland Assets (where benchmark norms had not been prescribed by the Company even by May 2015), some used the performance incentive norms, 2003 to prepare their RDPs while others had based their RDPs entirely on past performance. All offshore Assets and Basins prepared their RDPs based on past performance. Non-availability of norms and non-adherence to available norms led to distorted planning which resulted in un-reliable performance evaluation of the work centre and its employees.

(Paragraph 3.3.1)

Acquisition and hiring of rigs

The Company needs to hire rigs in a timely manner to ensure seamless drilling operations. During 2010-14, 13 contacts out of 23 tenders selected in offshore areas and 8 out of 9 tenders in onland areas were not finalised within the prescribed time norm (delays of upto 508 days noticed). There were persistent delays at each stage of the tendering process, in initiation and finalisation of the indent, issue of NIT, finalisation of the tender and even in signing of the contract. Delays were also noticed in cases where the rigs already in use were being re-hired. Delay in hiring process led to loss of 391 rig months during 2010-14 which rendered the Company unable to drill planned locations.

(Paragraphs 4.2 and 4.3)

Besides delay, Audit noticed deficiencies in the tendering process of the Company. In two tenders (out of 32 tenders finalised over 2010-14), the Company relaxed the Bid Evaluation Criteria (BEC) after bids had been received and, thus, accepted the rigs that did not conform to BEC. In both cases, rigs were not mobilised by the contractor subsequently and the Company lost precious rig months (in one case the loss was 33 rig months while in the other the loss was 15 rig months).

(Paragraphs 4.4.1 and 4.4.2)

Acquisition of new offshore rigs had been proposed in 2002 but no decision was taken for over a decade. Meanwhile, four out of six owned offshore rigs had outlived their economic life of thirty years. The decision regarding procurement of onland rigs was not consistent. While six onland drilling rigs were procured (2012) despite negative NPV and lack of rig discard policy, five mobile rigs were not procured on the same grounds. The latter five onland mobile rigs were required for replacing existing rigs already laid off/ proposed to be laid off and, therefore, the decision affected availability of onland mobile rigs.

(Paragraphs 4.6.1 and 4.6.2)

Deployment of rigs

One-third of the locations actually drilled by the Company during 2010-14 were not in RDP (615 unplanned locations drilled against 1,867 planned locations) which rendered the elaborate annual planning exercise for budgetary and revised estimates meaningless.

(Paragraph 5.1)

The planned availability of rigs for drilling was set at 95 *per cent* for owned rigs and 100 *per cent* for charter hire rigs. However, rigs remained out of cycle for prolonged periods which resulted in actual rig availability being much lower (87 to 91 *per cent*). During 2010-14, rigs remained out of cycle for 12 *per cent* of the available time leading to loss of 679 rig months. In the Western Offshore area, where the highest number of jack-up rigs (22 rigs) were deployed for development and exploratory activities, ₹ 517 crore was charged off on account of rigs out of cycle during 2010-14. Of this, 78 *per cent* (₹403 crore) pertained to owned rigs.

(Paragraph 5.2)

In addition to rigs remaining out of cycle, rigs remained idle for considerable periods even after being deployed for drilling. Idling of rigs led to lower utilisable rig months and increased drilling cost. Non Productive Time (NPT) of rigs in 2010-14 ranged between 19 to 23 *per cent*. While a fraction of NPT was on account of non-controllable factors like weather, the bulk of idling time (valuing ₹ 6,418 crore) was well within the control of the Company and could have been addressed through better planning and coordination. Rigs idled as the locations were not ready for drilling, for want of material supply and on account of non-availability of manpower. Even as rigs remained idle waiting for ready sites, facilities remained idle for want of deployment of rigs. In Mumbai offshore Asset, though 21 platforms were ready for drilling (2010-14), rigs had not been deployed and the platforms remained idle for upto 777 days which resulted in idling of facilities and deferment of estimated production valuing ₹ 4,003 crore (approx.) for oil and ₹ 1,174 crore (approx.) for gas.

(Paragraphs 5.3 and 5.3.1.2)

The Company overlooked safety procedures in drilling operations. Production testing operations were continued on an exploratory well (in KG Basin) even after the anchor of the rig Sagar Vijay snapped, though it was a serious safety lapse. This led to snapping of another anchor which caused the rig to drift by 140 metres from the location. The well had to be closed immediately and abandoned. The Company incurred an avoidable expenditure of ₹ 1,577.27 crore on account of this lapse. No insurance compensation could be received as established safety procedures had been violated by the Company.

(Paragraph 5.4.1 A)

The Company took nearly a year's time to terminate the contract with M/s. Shiv Vani Oil and Gas Exploration Services Limited, New Delhi. The problems in operation of the rig were known by March 2013, yet the contract was extended in April 2013. The notice for termination of the contract was issued in August 2013 (three months later) allowing 15 days for correction. The second notice was issued two months later in October 2013 allowing 30 days for correction. Six months later, in April 2014, the contract was actually terminated though the contractor had stopped work in November 2013.

(Paragraph 5.4.2.1)

The target cycle speed fixed for Drilling Services group in their performance contracts was consistently lower than the cycle speed targeted in the annual plans of the Company. While Drilling Services group over-achieved their performance target, the planned cycle speed was not achieved. Besides, the single target cycle speed fixed for Drilling Services group was not an appropriate benchmark to measure performance as the actual performance of onland and offshore rigs varied widely (against the target cycle speed of Drilling Services group of 677 metres, offshore rigs achieved only 353 metres while cycle speed of the onland rigs was 803 metres). Efficiency of the Company owned rigs was poor (ranging from 27 *per cent* to 49 *per cent*) with owned offshore shallow water rigs achieving less than half the cycle speed of hired rigs while the drilling cost of Company owned rigs was much higher (ranging from 34 to 131 *per cent)* than that of hired rigs.

(Paragraphs 5.5 A and 5.5.C)

Maintenance of Departmental rigs

The Company formulated (2007), a policy for dry dock management and major lay-up repairs of jack-up rigs and drew up a five year dry dock road-map for the jack-up rigs (purchased between 1982 and 1990) in May 2007. As per the road map, dry dock and major lay-up repairs of all six jack-up rigs was to be completed by 2009. As against this plan, repair of only three rigs had been carried out so far (April 2015) with the tender for repair of another rig under process. Non adherence to the repair schedule led to rigs being operated with outdated/ obsolete equipment which was not an efficient operational practice.

(Paragraph 6.1.1)

While establishing the rationale for repair and refurbishment of jack-up rigs vis-à-vis hire/ acquisition, the Company considered efficiency of old owned rigs to be on par with hired and newly acquired rigs. However, efficiency of owned rigs had always been much lower than that of charter hire rigs (over the ten year period 2003-13, the efficiency, in terms of cycle speed, of comparable charter hire rigs have been more than 2.52 times that of owned rigs). The proposal for repair of old rigs would not be economically viable vis-à-vis hire/ purchase of rigs if realistic efficiency of owned rigs were considered. Besides, there were inordinate delays in finalising the scope of work (36 months for rig Sagar Ratna and 48 months for rig Sagar Uday) which led to cost escalations (156 and 57 *per cent*) further skewing the financial viability of repairs.

(Paragraphs 6.1.2 and 6.1.3)

Post repair, the efficiencies of jack-up rigs and drillships did not improve significantly. Rig Sagar Vijay upgraded for drilling wells with water depth of 900 metres did not drill a single well of more than 400 metres water depth between 2005 and 2013.

(Paragraphs 6.1.4 and 6.2.2)

Recommendations:

1. The Company needs to ensure that the plans (five year plan, annual plan, rig requirement plan, rig deployment plan) are complete and consistent with each other. The Company should make efforts to adhere to rig deployment plans during actual drilling. The situation where one out of every three wells drilled is un-planned needs to be corrected.

2. The controllable non-productive time of past periods should not be loaded to future rig requirement plans. With induction of new technology and hi-tech rigs, realistic targets for rig requirement ought to be set to have the desired stretch in performance. Suitable measures need to be taken to reduce the non-productive time of the rigs, particularly in eliminating rig waiting due to controllable factors like waiting for locations, ready drill sites, environment clearance, material, manpower and logistics support.

3. Initiation of indents and tendering procedure for acquisition/hiring of rigs, which are entirely within the control of the Company, needs to be done on time with proper planning so that rigs are mobilised on time. In particular, indents for re-hire of rigs on expiry of their existing contracts should be issued expeditiously so that the Company does not suffer from non-availability of rigs between the periods of de-hire and re-hire. Considering that most offshore rigs owned by the Company had outlived their useful lives, policy regarding acquisition of rigs, pending for over a decade, should be finalised expeditiously.

4. The cycle and commercial speed targets for Drilling Services group should be aligned with the planned cycle and commercial speed of the Company. Considering the very different activities carried out in offshore and onland and the consistently poor performance of owned offshore rigs, there is a need for setting separate targets for each category and adequately monitoring for attainment of such targets.

5. Efforts need to be made to correct the imbalance in drilling manpower at the cutting edge, necessary for efficient operations of owned as well as hired rigs. A suitable review of the current position needs to be taken up by the Company and the position rectified in a time bound manner.

6. The assumptions made while analysing cost-benefit of repairing old owned rigs, having outlived their useful lives, should be realistic, based on past experience, particularly with regard to efficiency expected of such rigs after repairs. This would enable a balanced decision regarding major repairs of these rigs.

The Ministry of Petroleum and Natural Gas (MOPNG), while accepting all the recommendation, stated (August 2015) that the recommendations are for improvement of drilling performance and that the Company would be advised to follow all the recommendations of audit.

Chapter 1: Introduction

Oil and Natural Gas Corporation Limited (ONGC - hereinafter referred to as 'the Company') is an integrated Oil Exploration and Production Company (set up as Commission in 1956). The activities of the Company mainly consist of geological and geo-physical surveys, drilling of wells, production and sale of crude oil and natural gas and related research and reservoir studies in onshore and offshore areas.

The process of petroleum exploration starts with prognostication and geo-scientific surveys on the identified sedimentary basins. The information collected from these surveys is processed and interpreted to construct a logical model of the basin. The model so constructed, which is dynamic in nature and revised in different stages of exploration, is tested by drilling exploratory wells. If the area proves to be hydrocarbon bearing, delineation wells are drilled to ascertain the extent of the field and its productivity. This is followed by drilling of development wells, laying oil pipelines and installation of facilities to put the field on regular commercial production. During the producing phase of the field, the producing wells are maintained through work-over operations for maintaining the level of production or increase in production.

The Company conducts its exploration activities through Basins[1] and the production activities are carried out through Assets[2]. There were eight Basins and 11 Assets in the Company. The Basins and Assets are in onland and offshore (Shallow water and Deep water) areas. While the exploratory wells are drilled in Basins, the development wells are drilled in Assets. In addition, the Company carries out work-over operations in development areas to maintain production. Side-tracking operations are also carried out by the Company for exploration and development activities.

1.1 Functions of Rigs

Rigs are deployed for the following three purposes:

Exploratory drilling - Wells are drilled with a view to establish new hydrocarbon structure and include delineation wells drilled for delineation of the discovered structures.

Development drilling - It is carried out generally from a production site for which approved development schemes exist, with a view to produce hydrocarbons from them in commercial quantities.

Work-over operations - It includes repair/replacement of equipment in the well, for maintaining or enhancement of production.

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[1] ***Basins : Western Offshore, Western Onshore, Assam and Assam-Arakan, Mahanadi, Bengal and Andaman, Krishna Godavari, Cauvery and Frontier Basin***

[2] ***Ahmedabad, Mehsana, Ankleshwar, Assam, Tripura, Rajahmundhry, Cauvery, Mumbai High, Neelam-Heera, Bassein-Satellite, Eastern Offshore Asset.***

Side-track operations – To drill a secondary wellbore away from an original wellbore, which saves re-drilling the top part of the hole. A side-tracking operation may be done intentionally or may occur accidentally.

The drilling in offshore areas is carried out by different types of rigs *viz.* jack up rigs, (cantilever rigs, slot type rigs and mat supported rigs), semi-submersibles, modular rigs, platform rigs and drillships. In onland areas, mobile rigs and High Floor Mast / Sub structure types of rigs are used for drilling.

1.2 Financial Outlay

Drilling activities (both exploratory and development) in the Company are carried out by the departmental and hired rigs. As on March 2014, the Company had 112 drilling rigs. The onland rigs are largely owned by the Company (67 departmental rigs as against six hired rigs) while the more expensive offshore rigs are mostly hired rigs (31 hired rigs as against eight departmental rigs - six jack up rigs and two drillships).

The expenditure on exploratory and development drilling during 2010-11 to 2013-14 is tabulated below:

Table 1.1: Expenditure on Exploratory and Development Drilling

(₹ in crore)

Type of expenditure	2010-11	2011-12	2012-13	2013-14
Exploratory Drilling	8,625.27	8,463.02	10,037.56	11,452.00
Development Drilling	3,511.63	4,287.59	6,722.08	7,512.00
Total (Exp. & Dev. Drilling)	12,136.9	12,750.61	16,759.64	18,964.00
Total outlay	28,275.54	29,246.55	29,507.91	32,470.00
% of total Exp. & Dev. Drilling	**42.92**	**43.60**	**56.80**	**58.40**

Source: Annual Plan 2010-14

As can be seen from the above table, drilling activities constituted the single most significant expenditure of the Company, constituting as high as 42.92 *per cent* to 58.40 *per cent* of total expenditure of the Company during 2010-14. Besides, efficient drilling is critical for both production of hydrocarbons and reserve accretion. Hence, effective and efficient planning, deployment and utilisation of drilling resources are crucial for efficient operation of the Company.

Besides exploration and development drilling plan expenditure, the Company also incurs significant revenue expenditure on work-over operations to repair sick/non-flowing wells so as to maintain /increase level of production. The work-over expenditure incurred during the period 2010-14 is tabulated below:

Table 1.2: Expenditure incurred on work-over operations

(₹ in crore)

	2010-11	2011-12	2012-13	2013-14
Actual	2,768	2,341	1,904	2,094

1.3 Management of rig operations

The management of rig operations includes planning, hiring, acquisition and deployment of rigs. The Company prepares a Five Year Plan (FYP) duly envisaging the exploration, development and production activities in the forthcoming five year period. The approved FYP includes physical targets set for exploratory and development drilling in terms of meterage to be drilled, number of locations to be drilled through mix of owned and charter hired rigs. This forms the basis for a Rig Requirement Plan (RRP), (prepared for offshore areas alone) on a five-year basis for deciding on hiring/ acquisition of rigs, based on availability of rigs with the Company. The annual operational plans of the Company are drawn in line with the FYP and considering the planned production and commitments made in respect of NELP and PEL Nomination blocks. In line with the annual plans, the Company (Drilling Services group) also prepares a Rig Deployment Plan (RDP) for allocating rigs (both owned and hired) to specific work locations in consultation with Assets and Basins. While the wells to be drilled and their locations are decided by the respective Assets and Basins, the rig deployment plan, hiring of rigs and their actual deployment are the responsibility of Drilling Services group of the Company. The Company prepares Geo Technical Orders (GTOs) which is a micro level plan of a well to be drilled, specifying the timeline for each drilling activity.

Chart 1.1 – Planning process for rigs

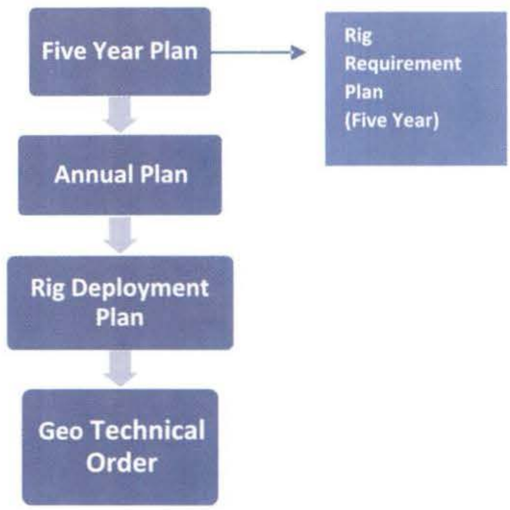
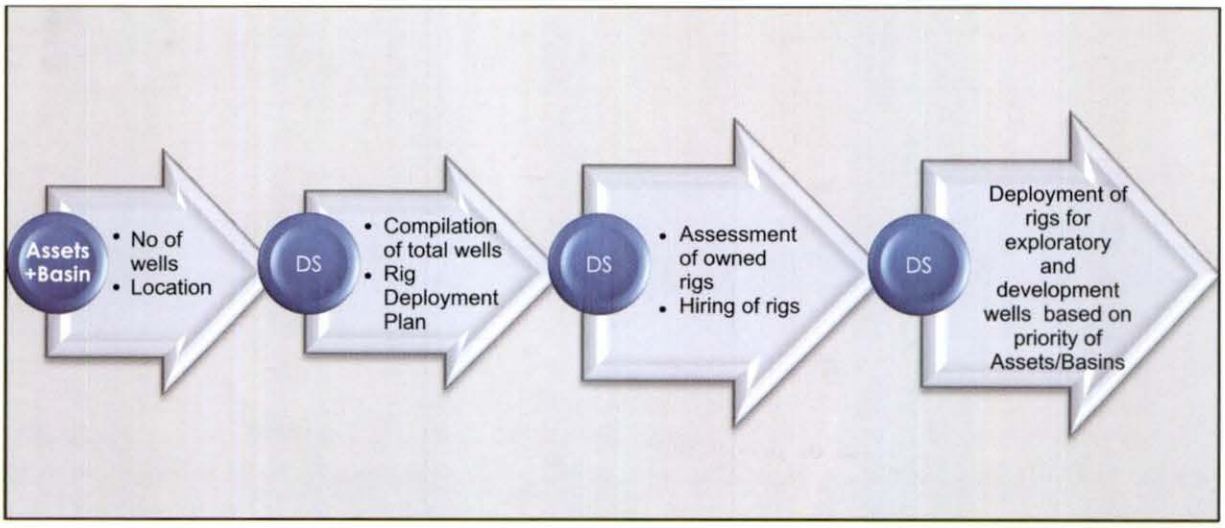


Chart 1.2 : Process of management of drilling operations



1.4 Organisation Structure

The technical control of Drilling Services group is under Director (Technical and Field Services - T&FS) who looks after planning, requirement and utilisation of drilling rigs. The administrative control of Drilling Services group for day to day operation of drilling services group is under Director (Offshore).

1.5 Performance of drilling operations

1.5.1 Exploratory and Development drilling

The performance of drilling rigs in the Company for the four years from 2010-11 to 2013-14 is tabulated below.

Table 1.3: Plan and actual performance of drilling operations

Drilling	2010-11		2011-12		2012-13		2013-14	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
Exploratory								
Meterage (KM)	514.97	384.02	505.87	375.44	502.75	343.052	480.35	320.76
Wells (Nos.)	154	125	158	135	155	108	153	106
Development								
Meterage (KM)	458.36	500.09	581.41	558.69	703.43	680.73	679.52	596.79
Wells (Nos.)	216	256	272	280	325	323	311	283

Source: Annual Plans and Director (T&FS) Report

The above table shows that while less than the planned number of exploratory wells had been drilled, development wells generally exceeded the target in 2010-11 and 2011-12.

The planned and actual utilisation of rig months for the period 2010-14 is tabulated below.

Table 1.4: Planned and actual utilisation of rig months

Rig Months	2010-11		2011-12		2012-13		2013-14	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
Onshore								
Exploratory	536.99	459.86	539.91	434.39	475.02	356.02	436.89	334.99
Development	422.29	435.69	418.48	463.74	543.82	486.95	488.88	439.72
Total	959.28	895.55	958.39	898.13	1018.84	842.97	925.77	774.71
Offshore								
Exploratory	218.77	196.09	172.06	147.66	223.71	162.20	215.50	200.90
Development	75.60	62.55	134.5	84.99	169.6	141.34	176.85	142.12
Total	294.37	258.64	306.56	232.65	393.31	303.54	392.35	343.02

Source: Annual Report (T&FS) 2010-14

The planned rig months could not be achieved in most cases. The planned targets were met only in 2010-11 and 2011-12 for development drilling in onshore areas. The reasons for non-achievement of planned rig months are discussed in Chapter 4 (paragraphs 4.2, 4.3, 4.4) and Chapter 5 (Paragraph 5.2).

1.5.2 Work-over operations

The planned and actual work-over operations both in onland and offshore areas during 2010-14 are tabulated below:

Table 1.5: Planned and actual work-over operations

Year	Location	Wells		Rig Months	
		Plan	Actual	Plan	Actual
2010-11	Offshore	142	122	159.3	127.9
	Onland	1375	1421	895	870.4
2011-12	Offshore	81	109	110.68	126
	Onland	1383	1532	936.85	916.6
2012-13	Offshore	59	72	76	83
	Onland	1392	1595	915.9	879.32
2013-14	Offshore	99	93	138	109
	Onland	1484	1581	916.7	887.55

From the above table, it can be observed that the Company had generally achieved the planned work-over operations in all the years except for two years (2010-11and 2013-14) in Offshore areas.

1.6 Drilling Efficiency of Rigs

The performance of drilling rigs is evaluated mainly in terms of two Key Performance Indicators (KPIs) *viz.* Cycle Speed and Commercial Speed.

Cycle Speed

The parameter used to evaluate the operational efficiency of rigs is Cycle Speed in metre/rigs months achieved in completing a well. It is calculated on dividing the drilled depth of well by the cycle time in rig months actually used for completing the well *i.e.* the time between rig release from previous well to rig release from present well after carrying out rig building, drilling and production testing operations at present well. The total time involved in these three phases is known as 'Cycle time'.

Commercial Speed

The parameter used to evaluate the drilling efficiency of rigs is Commercial Speed in metre/rig month achieved in drilling a well to the target depth. It is calculated by dividing the drilled depth of well by the commercial time in rig months actually used for drilling the well *i.e.* the time from spudding of a well to hermetical testing of production casing (to check any leakages before bonding over the same for production testing), also called 'drilling time' or commercial time.

Drilling efficiency of the rigs of the Company in terms of Cycle Speed and Commercial Speed has been discussed subsequently in paragraph 5.5 of the report.

Chapter 2: Audit Approach

The performance of offshore shallow water rigs had been reviewed by the Comptroller and Auditor General of India (C&AG) in Audit Report 9 of 2007 (Chapter VII). The present audit covers the drilling activities, both onland and offshore (shallow and deep water) carried out by the Company over the period 2010-14.

2.1 Audit Objectives

The objective of the performance audit was to obtain reasonable assurance that the Company had planned, hired, deployed and utilised rigs in an efficient and effective manner. Audit examined the following issues in this regard:

- Whether drilling rigs were properly planned and matched with the requirement of Assets and Basins;
- Whether requisite number of rigs were made available through hiring or acquisition in an effective and efficient manner to implement the plan;
- Whether deployment of rigs (drilling as well as work-over rigs) was as per plan and their utilisation had been efficient; and
- Whether maintenance/repair/ up-gradation of drilling and work-over rigs was as per maintenance plan and statutory or other requirements.

2.2 Scope of Audit

The scope of audit was to review overall performance of management of rigs by the Company during 2010-11 to 2013-14. This covered various sections, such as planning, procurement and hiring, operations and maintenance of rigs of Drilling Services and Well Services groups of the Company. The monitoring of the drilling performance at corporate level was also covered during the audit.

2.3 Audit Criteria

The following were the sources of audit criteria:

- 11^{th} and 12^{th} five year plan document along with the annual plan documents for 2010-14, budget estimates and rig deployment plans.
- Company's policy, rules and regulations including material management manual, norms fixed by the Company for drilling activities, dry dock policy, drilling manual, maintenance schedule of owned rigs, Geo Technical Orders of locations, *etc.*
- Minutes of the Board Meetings, spud meeting minutes, Multi-Disciplinary Team (MDT) meetings, norms/standards prescribed in the Company's internal documents, Service Level Agreements entered by Assets/Basins with other services groups of the Company, performance contract (PC) signed between/among services groups of the Company.
- Guidelines issued by the Government as well as health and safety guidelines prescribed by statutory bodies.

2.4 Audit Methodology

The methodology adopted for the audit was as follows:

- An Entry Conference was held with the Company for discussion on the audit objectives, scope and methodology in July 2014.
- This was followed by collection of information through audit requisitions and questionnaires. After scrutiny of records, discussion with the Company officials, and test check of the transactions, preliminary audit observations were issued. These were further reviewed based on the responses of the Company and consolidated to prepare the draft audit report.
- The draft audit report was issued to the Company (November 2014) and reply of the Company was received in April 2015. Reply of the Company has been suitably incorporated in the report.
- An Exit conference to discuss the response of the Management on the audit findings was held on 2 May 2015. The views expressed by the Company during this meeting and the supplementary information provided during the meeting have also been suitably incorporated in the report.
- The draft report was issued (June 2015) to the Ministry of Petroleum and Natural Gas (MOPNG) and reply of MOPNG was received in August 2015. Reply of MOPNG has been suitably incorporated in the report.
- An Exit conference with MOPNG and Management of the Company to discuss the response of MOPNG on audit findings was held on 10 August 2015. The views expressed by MOPNG and the Company during this meeting and post Exit conference supplementary reply of the Company as forwarded by MOPNG (August 2015) have also been suitably incorporated in the report.

2.5 Sampling

The following sample was scrutinised for the Performance Audit:

Table 2.1: Sampling methodology

Sl. No.	Item / activity	Population	Sample size	No. Selected
1	Tenders for hiring of rigs	32	100 %	32
Performance of Offshore rigs				
2	Owned rigs	9	100%	9
3	Hired rigs –Deepwater	6	100%	6
4	Hired rigs – Shallow water	31	20%	7
5	Work-over hired rigs	3	20%	1
Performance of Onland rigs				
6	Owned rigs	68	20%	14
7	Hired rigs	16-20	20%	4
8	Work-over- hired rigs	19	20%	4
9	Work-over -Owned rigs	53	20%	11

The sample selected was a risk based one.

- All tenders for hiring of rigs were selected in view of high materiality and criticality of rigs for drilling operations.
- While reviewing performance of rigs, all owned offshore rigs were selected as their performance was poor with high non-productive time and significant expenditure was incurred on their repair and maintenance during the period of audit.
- Performance of all deep water rigs was scrutinised in view of their high costs and impact on exploration and development targets of NELP blocks.
- For charter hired offshore rigs, onland rigs and work-over rigs, a sample of 20 *per cent* had been selected. The selection was on the basis of materiality (higher operating day rates) and risk (lower cycle speed and commercial speed, higher non-productive time) of the rigs.

2.6 Acknowledgement

Audit wishes to acknowledge the cooperation and assistance extended by the Ministry of Petroleum and Natural Gas (MOPNG) and the ONGC Management in the conduct of this performance audit.

Chapter 3: Planning of Rigs

The Company prepares a Five Year Plan (FYP) specifying the annual targets for the number of wells to be drilled and the meterage to be achieved in drilling to meet its five-year hydrocarbon production and reserve accretion targets. Development drilling aims to achieve production targets and requires facilities to be completed and prospective locations made ready in time for drilling. Exploratory drilling is carried out to meet targets of reserve accretion and acreage up-gradation as well as to fulfill time-bound Minimum Work Programme (MWP) commitments in NELP blocks. Besides the five year plan, the Company also prepares an annual plan which specifies the number of wells and meterage to be drilled in the year. The FYP and annual plan are expected to be broadly compatible.

The FYP forms the basis for a Rig Requirement Plan (RRP) for offshore areas, also prepared on a five-year basis. The five-year RRP is necessary for deciding on hiring/acquisition of rigs based on the rigs available with the Company. Long term planning is essential as the hiring/ acquisition of rigs has a considerable lead time. In line with the annual plans, the Company also prepares a Rig Deployment Plan (RDP) for allocating rigs (both owned and hired) to specific work locations.

3.1 Inefficiencies built in the five year RRPs

Based on the FYP, the Drilling Services group of the Company works out the RRP on a five-year basis. The five-year RRP assesses the rig months (RMs) required for achieving the FYP and works out the number of rigs required by the Company in the next five years. To arrive at the RMs required, an internal Multi-Disciplinary Team (MDT) considers the work programme for exploration and development and adopts a set of norms to arrive at the RMs requirement. These norms were based on past drilling experience (average drilling time taken for completing different type of wells during previous years) and are brought out in ***Annexure I.***

It may be observed from ***Annexure I*** that the rig requirement for side track wells had gone up from 40 to 47 days and in respect of work-over operations from 20 to 23 days from XI FYP to XII FYP.

3.1.1 Higher RMs planned based on past performance

The increase of 7 days per side track well and 3 days per work-over operation over the XI plan norms was because the rig requirement was worked out based on the past performance which was inclusive of non-productive time (NPT). The NPT in the XI plan was 23 to 28 *per cent* which was significantly high (as compared to the global norm of 12 *per cent*). The MDT, in the XII FYP, had considered an improvement of drilling efficiency by 5 *per cent* on account of technology up-gradation, improved monitoring to cut down NPT and reduced well complications, while working out the rig requirement. However, as the NPT (upto 28 *per cent*) far outstripped the efficiency increase (of 5 *per cent*) considered, the rig requirement plan assessed a higher requirement of RMs and had an in-built inefficiency. The higher provision of RMs also needs to be considered in the context of technology up-gradation and induction of new generation rigs by the Company for the express purpose of higher efficiency and reduction of NPT. The Company had planned to induct five new generation rigs in XII Plan as against three in XI Plan. The new generation rigs had proved to have better drilling performance in terms of higher commercial speed, lesser NPT and drilling of hi-tech wells. Besides, various drilling technology like SOBM[3], SDMM[4], High performance mud systems *etc.* had been inducted and their positive impact had been experienced.

The Company stated (April/ May2015) as follows:

(i) RMs and ultimately number of rigs required was calculated based on past drilling experience based on average drilling time taken for completing different type of wells during previous years. Abnormal days were excluded from planning for drilling days, as far as practicable. However, some of the NPT over which the Company had no control needed to be included in the plan. As more and more wells were drilled, lessons learnt were assimilated/ incorporated in future planning.

(ii) Every well was a separate project in itself. Normally, at the time of preparing FYP (Five Year Plan) / RDP (Rig Deployment Plan) only primary details related to sub-surface location of the well was available and tentative meterage(s) were worked out based on it. The actual requirements were made available only when well was actually taken up for drilling. Therefore, no single rule for drilling time could be made applicable to all wells drilled in wide variety of formations and different sub surface conditions. The planned days for each well could be decided precisely only after geological prognosis of that well was available. Therefore, during initial planning, tentative RMs were considered as per past experience which was regularly updated based on recent experiences.

(iii) Drilling workload for the year 2014-18 for hiring of offshore drilling rigs was based on reduction of 5-10 *per cent* of average drilling time of past 5 years so as to address improvement in efficiency due to induction of new technologies and at the same time not to include controllable past inefficiencies such as waiting on logistics, material/men *etc.*

Reply of the Company needs to be viewed in the following context:

(i) The Company agrees that RMs and, hence, rig requirement was worked out on the basis of past drilling experience. While the need for including non-controllable delays in operation (based on past performance) was appreciated, it was seen that the controllable NPT far outstrips the non-controllable component. The controllable NPT in Western Offshore area where maximum rigs were deployed during 2010-14 was 86.26 to 93.89 *per cent*[5] of the total NPT. Hence, the Company should have reduced controllable NPTs (may be in line with global standard of 12 *per cent*) while working out the RMs and number of rigs required so as to have the desired stretch in the performance targets for drilling of wells.

[3] ***SOBM – Synthetic Oil Base Mud.***
[4] ***SDMM - Steerable downhole mud motor.***
[5] ***Total offshore shallow water NPT of 19.0 to 22.9 per cent.***

(ii) The contention of the Company that abnormal days were excluded while working out RM requirement for the next five years was also not acceptable as abnormally high drill days taken by two rigs, rig Discovery 1 (166 days/well) and rig George McLeod (115.93 days/well) for development wells during 2010-12 was considered by MDT while arriving at RRP for XII FYP even after being pointed out internally by the Finance wing.

(iii) While the contention of the Management that no single rule for drilling time could be made applicable to all wells was appreciated, the Company had arrived at the RMs requirement on the basis of average past performance (considering the drilling time taken by each rig in the past periods) and, hence, would largely address the individual complexities.

(iv) Review of rig requirement for the years 2014-18 revealed that there was no reduction in average drilling time for different category of wells viz. development, side track and work-over wells as compared to approved drilling time in RRP for XII Plan period.

MOPNG stated (August 2015) that the Company is carrying out benchmarking norms in phased manner for different work-centres in Onshore and Offshore. Moreover, the Company is also in process of carrying out modalities for defining benchmarking norms from a reputed International agency as per international standards. These benchmark norms are worked out from optimal performance and effects of controllable NPT such as waiting on logistics, material/men would be addressed accordingly keeping in view to not include controllable past inefficiencies and also benefits of inducting new technologies would be considered. The Company is also in touch with a reputed service provider to induct new technologies suitable to address downhole complications. All out efforts would be made to reduce controllable NPT.

The Company also stated (August 2015) that more days were planned in XII FYP over XI FYP for side track and work-over wells due to ageing of fields and for subduing old wells.

Once benchmark norms of international standards are adopted it is expected that the planning process would be streamlined. The same would be watched in future audit.

3.2 Inconsistencies between FYP and RRP

A) Incomplete RRP for onland areas

The RRP prepared for a five year period included only the offshore rig requirements. The five year onland rig requirement plan was not prepared by the Company. Even though the XI and XII Five Year Plan included the number of onland wells (both exploration and development wells) to be drilled as well as their meterage, commensurate five year plan for rig requirement was not carried out. It was noticed that an annual Rig Deployment Plan (RDP) alone was prepared for onland Assets and Basins on which basis decisions of hiring of rigs were taken. Considerable delays in hiring had been noticed which had led to rigs not being made available to the Assets and Basins on time as detailed in paragraph 4.3. A longer duration RRP, as in offshore areas would facilitate hiring decisions and ensure timely availability of rigs in onland areas. During Exit Conference (May 2015), the Company agreed in principle for preparation of RRP for onland rig requirement. The same was reiterated by MOPNG (August 2015). However, in the supplementary reply post Exit Conference, the Company stated (August 2015) that preparation of five year RRP is not possible for onland rigs considering the geographical spread of onland locations and disadvantages in movement of rigs across locations; hence, the difficulty in clubbing requirements at a central place. It was, however, assured that efforts would be made to minimize the gap between plan and actual by strengthening planning and co-ordination with Assets and Basins.

The supplementary reply given by the Company may be viewed in the light of the fact that delays have been noticed in hiring of onland rigs, which ultimately resulted in non-achievement of drilling targets in various Regions. The RRP is a tool for estimating the five year rig requirement to facilitate timely hiring.

B) Non consideration of wells of two Assets in XI FYP

In the XI FYP, the Company planned 14 development wells for Neelam Heera Asset and 26 development wells for Bassein and Satellite Asset. Audit noticed that the Rig Requirement Plan (RRP) for 2007-12 (September 2007) included a workload of 46 wells in Neelam Heera Asset and 74 wells for Bassein and Satellite Asset. Thus, a significant lower number of wells in the two Assets were planned in XI FYP vis-à-vis the Rig Requirement Plan.

The Company stated (May 2015), in case of Neelam Heera Asset, development wells were meant for augmenting oil production from the field. The five year plan was prepared considering available inputs in the form of approved and conceptual development locations at that time and there was no shortfall in planning in the FYP. As regards Bassein and Satellite Asset, the Company stated that while working out XI FYP, inputs envisaged in approved development schemes were considered in the plan proposal.

MOPNG stated (August 2015) that in respect of Neelam Heera Asset, Heera Redevelopment Project (HRP) was still under study when the firm profile for XI FYP was frozen (July 2006) and HRP was approved on September 2006 only. In case of Bassein and Satellite Asset, development schemes approved subsequently during XI plan period were included in annual regional RDP in addition to the wells approved in XI FYP. In supplementary reply (August 2015), Company stated that in respect of Bassein and Satellite Asset, along with 26 development wells, another 46 wells were planned during XI FYP for which development schemes/ feasibility reports were under preparation or under approval stage.

Reply of the Company was not acceptable since 34 wells of HRP that were approved (September 2006) at an estimated cost of ₹ 2,305.30 crore could have been considered in the XI FYP (March 2007). Further, by September 2007, the Company had assessed a workload of 46 wells for RRP (September 2007) but only 14 wells had been planned in the FYP. Similarly in Bassein and Satellite Asset, 74 wells (SB-11, Vasai East, D-1, B-22, B-193 and C series platform) had been considered in RRP of which only 26 wells were planned in XI FYP. As FYP forms the basis for the RRP, there was a need for consistency between the two plans. The very large difference in a short span indicates inadequacy in planning.

C) Non consideration of side track operation

In FYP, the Company did not include side track operations. These activities also generate incremental hydrocarbon production and reserve accretion and were essential activities of the Company. It was noticed that while the FYP did not include these targets, the RRP laid down rig requirements for side track operations. It was seen that in the Western offshore alone, the five year RRP for 2012-17 assessed a requirement of 14,006 rig days for side tracking against the total requirement of 37,404 rig days (37 *per cent* of the planned rig days) for development. Considering the volume of work, non-inclusion in FYP had led to a significant mismatch between the FYP and the RRP.

The matter had earlier been highlighted in C&AG's Report No. 9 of 2007 (Paragraph 9 of Chapter VII on 'Performance of offshore rigs in shallow water areas of ONGC'). The Company, in its Action Taken Note had assured (February 2011) that the planning of side track and work-over wells in FYP was noted for future compliance. However, the Company was yet (May 2015) to implement this assurance.

In the Exit Conference (May 2015), the Company agreed in principle for inclusion of side track operations in the ensuing five year plan. It was also observed that the Company in its Annual Plan for 2015-16 (Budget Estimates) included the side track wells costing ₹ 1,819 crore. MOPNG stated (August 2015) that the same was examined in-house in the Company and it was found that side track jobs are need based depending on the performance of wells/ reservoirs, and it would be difficult to include side tracking in the long term plan.

The reply of MOPNG needs to be viewed in the light of the fact that side track operations form a substantial work load of the Company (more than one third of the planned rig days for development). Besides, the side tracking wells have been considered in the five year RRP and, hence, was possible to plan. For a realistic five year plan, it is, therefore, essential to incorporate side track requirement to the extent feasible which would align the FYP to RRP/ Annual Plan.

3.3 Inefficiencies in Rig Deployment Plan

Rig Deployment Plan (RDP) was based on the Annual Plan and is prepared by the Drilling Services group of the Company with inputs from the Assets and Basins. After detailed deliberations with Assets/Basins, Drilling Services group finalises the revised estimates (RE) of Rig Deployment Plan taking into account the priortisation and rig availability. For onland work-over wells, rig deployment was planned by onland Well Services group of the Company.

Audit noticed that different benchmarking norms were employed by the onland work centres to arrive at the rig deployment plan (the rig to be deployed and the period of deployment). In contrast, no benchmarking existed for offshore areas.

3.3.1 Rig Deployment Plan and benchmarking norms

In 2003, the Company implemented the Performance Incentive Scheme that included, *inter-alia,* time norms for various operations in drilling, for both onland and offshore areas. Achievement of the time norms would make an employee eligible for incentives. The scheme was intended to streamline and bring transparency to the incentive payment system. Subsequent to introduction of Performance Related Pay in 2007-08, this incentive scheme had been withdrawn by the Company. Subsequently, Institute of Drilling Technology[6] (IDT) prescribed (June 2011) a set of benchmarking norms which indicated time norms for drilling operations of development wells in some onland areas (Cauvery, Rajahmundry, Ahmedabad, Ankleshwar, Mehsana, Cambay and Assam work centres). These time norms were to be used for preparing Geo-Technical Orders (GTOs), bar chart and drilling plans. The benchmarking for development wells in other work centres (*viz.* Assam and Tripura Assets) and exploratory wells in all onland Basins were in the process of finalisation. No such benchmarking exercise had been initiated for offshore work centres.

In this regard audit observed that

(i) No time norms were available for offshore areas even though it constituted 47.1 to 58.47 *per cent* of the total drilling expenditure of the Company during 2010-14. While the onland work centres were adopting the incentive norms of 2003 for exploratory wells and 2011 benchmarking norms for development wells for the rig deployment plans, the offshore work-centres did not use them and relied upon past experience which had in-built inefficiencies on account of higher NPT and non-consideration of technological advancements.

(ii) The days planned for drilling of development wells, work-over wells and side track wells for the Western offshore areas in the annual RDPs (BE) was higher than the days planned in the XII RRP for offshore rigs. As already pointed out (paragraph 3.1.1), higher number of days had already been planned in RRP (XII Plan) for these wells. With yet higher number of days planned in the RDP, the Company added further inefficiencies in the drilling plans as shown in the table alongside. The excess days planned in the RDPs in comparison to the RRP (XII Plan) for the year 2012-14 were 786 rig days (25.85 rig months).

Table 3.1: Excess rig days in RDP as compared to RRP

	Dev. Wells	Side track/Drain Hole	Work-over
Days estimated in RRP	55	47	23
2012-13 RDP (BE)	57.29	51.98	23.06
2013-14 RDP (BE)	56.90	51.33	24.64

(iii) There was also a divergence in the norms used by onland work centres for preparing RDPs.

[6] *An internal institute of the Company, located at Dehradun.*

a. While some onland Assets *viz.* Cauvery, Rajahmundry and Assam Assets used the benchmarking norms prescribed in 2011 for development wells; other Assets *viz.* Assam, and Tripura Assets use the past experience for preparing the RDP since no benchmark norms were available.

b. In case of Western onshore, the work-centres (Ahmedabad, Ankleshwar and Mehsana Assets) did not adhere to the benchmarking norms, though prescribed in 2011 itself, while preparing the RDP. Instead, the work centres adopted cycle speeds calculated by dividing the meterage to be drilled with the rig months available without any consideration of norms or past performance. This resulted in preparation of RDPs by adopting different cycle speeds in different years without any basis resulting in consistent over-achievement by these work centres as depicted in the table alongside.

Table 3.2: Comparison of Planned and Actual Cycle Speed in Western Onshore Areas

Assets	2010-11		2011-12		2012-13		2013-14	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
Ahmedabad	1,243	1,525	1,359	1,515	1,181	1,433	1,148	1,451
Ankleshwar	856	879	717	847	828	985	815	904
Mehsana	1,059	1,421	1,422	1,445	1,238	1,486	1,300	1,527

c. Though there were no benchmark norms for onland exploratory wells, Cauvery Basin, KG-PG Basin, Assam and Assam Arakan Basin and Forward Base, Silchar adopted time norms prescribed in the erstwhile performance incentive scheme, 2003 for their RDPs. However, Mahanadi, Bengal and Andaman Basin and Frontier Basin used the past experience for preparation of RDP for exploration wells. Thus, there was no uniformity in preparing the RDP for exploratory and development by the onland work centres.

d. Ankleshwar, Ahmedabad, Mehsana, Cauvery and Rajahmundry Assets, where the benchmarking norms for development wells had been prescribed in 2011, planned for excess days *i.e.* 17.56 rig months for rig building in RDPs during 2012-14. Similarly, during the period 2010-11 to 2013-14, there was an excess planning of 112 rig months for drilling in Cauvery Basin/Asset and KG Basin/Rajahmundry Asset compared to the benchmarking norms 2011 for development drilling and time norms under performance incentive scheme 2003 for exploratory drilling.

There was, thus, no uniformity in arriving at the rig deployment plans. Besides a significant degree of inefficiency was already built into the plans. Non availability of norms and non-adherence to available norms led to distorted planning which resulted in un-reliable evaluation of performance of the work centre and its employees.

The Company replied (April 2015) that development wells were planned based on benchmark norms fixed in July 2011 and exploratory wells on Performance Incentive norms of 2003 for onland areas. Benchmark norms provided normative days for conventional wells. However, as more and more complicated deep/hi-tech wells were being drilled in hostile formation having many uncertainties, additional days were planned for these wells based on past performance. Further, benchmarks or drilling efficiency (cycle and commercial speed) were not available for Silchar, Jorhat, Agartala work-centres and Geleki field in Assam due to limited data. IDT Dehradun was carrying out benchmarking norms in phased manner for different work-centres in Onshore and Offshore. Moreover, the Company was also in process of carrying out modalities for defining benchmarking from a reputed International agency. These benchmark norms were worked out from optimal performance and effects of controllable NPT such as waiting on logistics, material/men would be addressed accordingly keeping in view to not include past inefficiencies and also benefits of inducting new technologies would be considered.

While the Company's plan to address the effect of controllable NPT in the benchmark norms in future was appreciated, the present system is inadequate as discussed below:

(i) The benchmarking norms, wherever available, had not been uniformly adopted. While additional days for specific activities had been planned for some work centres, in other cases, incorrect cycle speed had been adopted. Thus, the Company's contention that planning was based on benchmark norms, 2011 for all onland development wells was not acceptable.

(ii) Benchmark norms are expected to be indicative of the work centre for which the norm had been prepared after due diligence. Providing additional time on a case to case basis would negate the very purpose of benchmarking norms. Besides, as these norms were benchmarks for good performance, they needed to be in-built in the plan and performance of the work-centre to be assessed on these targets.

MOPNG stated (August 2015) that from the current year, the performance contract is signed based on strengthened target of benchmark norms. Benchmarking norms for onland and offshore is in progress; moreover, an international consulting firm is also being hired for this purpose. Norms for well services group have also been made more stringent. Henceforth, the plan shall be based on the revised time norm only. In the Exit Conference (August 2015) the Company assured that once the benchmark norms are in place, the same would be considered for evaluation.

Audit acknowledges the corrective action proposed; the same would be watched in future audit for their adoption and timely implementation.

3.4 Inefficiencies in preparation of Geo Technical Order

A Geo Technical Order (GTO) was prepared for each well to be drilled (both exploratory and development). This was a micro level plan prepared by the geology sections and specified the number of days required for each activity, service and material required for drilling a well and was signed between the Asset/Basin and Drilling Services group of the Company.

Audit observed the following discrepancies in preparation of the GTOs:

- **Inconsistency in adoption of norms:** As for preparation of RDPs, no norms were available for offshore drilling. In onland areas, the performance incentive norms, 2003 and the benchmarking norms, 2011 (wherever available) were used with the exception of Tripura Asset and MBA Basin where past experience was considered for preparation of GTOs. However, the norms were not appropriately applied in working out the rig days. Test check of KG-PG Basin revealed that rig building days were not planned in 41 GTOs of exploratory wells in KG-PG Basin. Production testing days were also not planned consistently (only 5 out of 41 GTOs had planned for production testing).

- **Delay in signing GTOs:** GTOs of well locations need to be signed (among Drilling services group, Assets/Basins and other relevant services groups of the Company), seven days before spudding a well. Out of 1,616 wells drilled, Audit reviewed 306 GTOs in onland and offshore areas and noticed that in only 37 *per cent* of the cases, the GTOs were signed well within time. In the balance cases, 101 GTOs were signed one to six days before spudding of the wells and another 91 GTOs were signed only after spudding of wells. In Assam Asset, inordinate delays upto 300 days were noticed in signing the GTOs.

The Company replied (April 2015) that efforts were being made to avoid delay in preparations of GTOs. GTO was a well program involving all geological and technical data of the well. However, before rig mobilisation, different meetings like Spud Meeting take place within different groups such as Geology, Drilling, Mud Services, and Completion *etc.* where all Geological, Geophysical and Geochemical (G&G) data and well inputs were deliberated. So, any delay in GTO would have limited effect on rig waiting for material/manpower. Further, as per recent EC decision, to improve the process of GTO preparation, GTO under preparation would be carried out in ICE[7] platform to facilitate planning, allocation and acquisition of required resources to drill those locations expeditiously. Once new field specific benchmark norms for different work-centres in Onshore and Offshore were in place, the same would be incorporated in ICE system to facilitate adherence to benchmark norms and consistency in well-wise plan for drilling days. In view of inconsistency in planning pointed out by Audit, work-centres were being advised that rig requirement plan may be worked out on the basis of New Benchmark Norms to avoid include past inefficiencies. MOPNG agreed (August 2015) to the corrective action proposed by the Company.

The assurance of the Company regarding adoption of benchmark norms and timely preparation of GTOs would be watched in future audit.

[7] ***ICE – Information consolidation for efficiency***

Chapter 4: Hiring and Acquisition of Rigs

4.1 Hiring of rigs

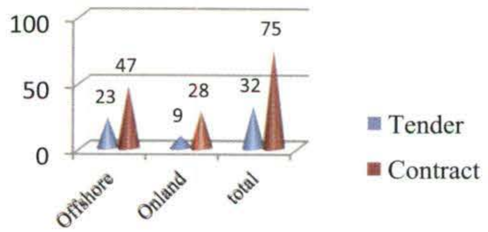
In line with the five-year Rig Requirement Plan (RRP) in offshore areas, and taking into account the available rig resources with the Company, plans for hiring rigs were initiated in offshore areas. In the absence of five-year RRP in onland areas, the hiring decisions were taken on an annual basis based on the Rig Deployment Plans.

The hiring decisions take into account the rigs owned by the Company. The Company owned eight offshore drilling rigs, 67 onland drilling rigs and 56 onland work-over rigs as on March 2014. During the period of audit (2010-14), no offshore rigs were acquired though the Company acquired six onland rigs.

Based upon availability of rigs (owned and continuing under hire), the Drilling Services section decide requirement for fresh hire. Rigs were generally hired on long term basis for a period upto three to five years through International Competitive Bids (ICB) as per procedure prescribed in the Material Management (MM) Manual.

This rig requirement was communicated to the MM section through an indent. On receipt of the indent, the MM section initiates the process of hiring the requisite number of rigs. The process involves issuing Notice Inviting Tender (NIT), a two-bid process in which the technically qualified bidders were first shortlisted and the winning bid was selected based on lowest financial bid. During the period 2010-14 the Company floated 32 tenders (23 for offshore and nine for onland areas). Of the 23 offshore tenders, six tenders were on nomination basis and 17 were International Competitive Bidding (ICB) tenders. The six tenders on nomination basis were completed in time. Against these 32 tenders, a total of 74 contracts were entered for charter hire of rigs.

Chart 4.1
Tenders floated and contracts awarded



Audit scrutinised all the 32 tenders. Delays and deficiencies noticed are discussed below:

4.2 Delay in hiring offshore rigs

To ensure seamless drilling operations, the Company should hire offshore rigs in a timely manner so that drilling activities were not delayed for want of rigs. As per MM manual, the Company requires a maximum period of 375 days for finalisation of contract and mobilization of an offshore rig (145-195 days for finalisation of contract and 180 days from the date of firm order for the Indian bidders for mobilization of the rigs outside Indian waters). Hence, the tendering process should be initiated well in advance to enable drilling on the locations which have been released after significant cost and time (for acquisition, processing and interpretation of seismic data) and also to achieve the exploration and production targets as planned in the FYP and Annual Plans.

Audit scrutiny of the tendering process in the 23 offshore tender cases (17 ICB tenders and six nomination cases) revealed persistent delays at every stage of ICB tenders. The six nomination cases and three ICB tenders were finalised in time.

Chart 4.2: Impact of delay in tender process

- In 13 contracts, the tenders were initiated late. As against the stipulated 375 days (maximum) requirement for finalisation of tender and mobilisation of rig, these tenders were initiated 311 to eight days before requirement (considering the de-hire dates of existing rigs and drilling needs). Thus, even at the time of initiation of the tendering process, it was clear that the rig requirement could not be met in time.
- NIT has to be finalised and issued within 20 days from the date of receipt of indent (as per the MM manual). Audit observed that in 9 contracts, NIT was delayed, the delay ranged from 11 to 300 days. On scrutiny, it was observed that the delays were attributable to receipt of incomplete indents from drilling section or indents that were received without expenditure sanction.
- Following issue of NIT, the tender should be finalised and the contract awarded within 120 days with an additional 20 days for each round of clarification and 5 days if Director's approval was required and 15 days for EPC approval of Letter of Award (LOA). Of the 17 ICB tenders, only three could be finalised in time. The contracts of remaining 14 tenders were delayed by 20 days to 331 days.
- Delay was noticed even in signing of contracts. As against the time limit of 30 days for signing the contract, the actual time taken ranged from 21 days to 313 days. Further, 15 contracts were not signed at all. Audit noticed that the four contracts arising from the nomination tenders were signed nine months after the completion of the contract period.

The delays on account of late initiation of the tendering process as well as delay in tendering process and mobilization of the rigs resulted in loss of 190.27 rig months (Exploration: 97.5 months and Development: 92.77 months) for offshore rigs.

4.2.1 Out of 23 tenders for hiring offshore rigs scrutinised by Audit, two individual instances of controllable delay in re-hiring and indenting are discussed below along with their effect:

A. Delay in floating tender led to deferment of revenue

The Company floated (November 2009) a tender for hiring seven jack up rigs for Mumbai Region against the rigs that were getting de-hired during January to April 2010. The Company, thus, had 60 to 150 days to finalise the contracts and get the rigs mobilized for continued drilling operations. Hiring of new rigs before de-hire of the existing rigs was not feasible considering the maximum 375 days benchmark for tendering and mobilization as per MM manual. Even then, the Company decided to de-hire all the seven existing rigs 30 days in advance citing downward trend in the rig day rates. In a review meeting (December 2009), the Company anticipated that as a result of de-hiring of rigs, it would suffer loss of 14.7 rig months in 2009-11 along with a shortfall of three development wells (NEA-5H & 6H, B-

134), 4 side track wells (BE-8ZH, NK-2z, 3z and B-173A) and seven work-over jobs on platforms IQ, BE and BA of Mumbai Offshore and that non-completion of these development and side track wells would lead to deferment of production of about 4,000 BOPD[8].

The contract was finally awarded in April 2010 and the rigs were mobilized between May 2010 and January 2011. As the rig requirement was an urgent one, the Company resorted to hiring rigs on nomination basis in the interim for drilling of these urgent wells. The planned wells could be drilled after a delay of 23 to 291 days and led to cumulative deferment of production for 780 days.

The Company stated (April 2015) that rig hiring indent was a consequence of estimation of workload for the forthcoming period from Assets and Basins and was not directly linked to the forthcoming de-hiring of the rigs. The tender was invited in November 2009 and based on certain queries on modification to technical specifications, amendments in tender clauses were made in January 2010 and it was finalised in April 2010. The Company also stated that the decision for early de-hire of the rigs was made in view of the significant downward trend observed in rig day rates and that the rates at which the nomination hiring was done was at rates lower than the previous hiring rates as well as subsequent tender rates. The Company further added that this led to deferment of production. Decision of the Company to de-hire rigs without making a timely arrangement for replacement of the existing ones was not a prudent practice.

MOPNG in its reply (August 2015) assured that "decision to de-hire rigs without suitable replacement in place" will be kept in mind in future hiring of rigs. The assurance given by MOPNG would be watched in future audit.

B Delay in re-hiring rig led to avoidable expenditure

The Company had hired Rig Badrinath for a period of three years ending 09 October 2010. The rig was de-hired on 8 October 2010. Subsequently, the Company decided to re-hire the rig on nomination basis at the earlier contracted rate for 90 days for drilling well D-11-A. The firm order for re-hire was placed in November 2010 and the rig was mobilised on 3 December 2010. The well was spudded on 11 December 2010. Due to complications faced during drilling the well, the rig took extra time (a total of 204 days) upto 2 July 2011. Rig Badrinath waited on weather for de-anchoring from 3 July to 10 August 2011 (39 days) and the Company, accordingly, incurred an avoidable expenditure of ₹ 10.94 crore.

Audit observed that prior to end of the existing contract, the Company had planned to deploy the rig Badrinath to drill two wells B-100-D (May 2010 to August 2010) and D-11-A (August 2010 to December 2010) in succession. As per terms and conditions of the contract, the contract could have been automatically extended at the same rates for completing the well, if the rig had been deployed on the well 30 days prior to the expiry of the contract *i.e.* 30 October 2010.

The drilling of well B-100-D was actually completed on 26 September 2010. Considering rig move to the new location, rig Badrinath could, therefore, have been deployed at D-11-A

[8] ***BOPD – Barrel of oil per day***

location within 30 days prior to contract completion date (30 October 2010). As the Company was aware that it had more than 30 days prior to the expiry of contract in September 2010 itself, the rig could have been deployed in location D-11-A as per the contract provisions and the well completed without going in for de-hiring and re-hiring. Instead, the Company initiated the rehiring process in October 2010 and the rig was made available only in December 2010 leading the drilling period up to monsoon. Had the Company deployed the rig in well D-11-A after completion of drilling the well B-100-D in September 2010, the drilling would have been completed by 22 April 2011 (considering 204 days actually taken for drilling the well) and the rig would not have waited for weather for de-anchoring. Due to non-deployment of rig in the well D-11-A in September 2010 which was allowed under the contractual terms *i.e.* 30 days prior to the expiry of the contract and the delay of two months in re-hiring the same rig, the drilling extended upto monsoon period and resulted in avoidable expenditure of ₹ 10.94 crore due to waiting on weather for de anchoring of the rig.

The Company replied (April/May 2015) the following:

(i) The well D-11-A was planned to be taken up by rig Badrinath after completing well B-100-D. Since there was considerable time available for de-hiring of the rig after completion of the well B-100-D and in view of the contract clause wherein the contract stands extended automatically under the same rates and terms and conditions till the completion of the well/ termination of the well, nomination case for hiring was not thought pertinent to be initiated.

(ii) As per contract clause 1.3(d) (for the well B-100-D), the Operator (the Company) shall have the option to terminate this agreement, at any time during last 30 days before the expiry date of the Primary Term or any extension thereof, if (a) the last well being drilled was completed or abandoned prior to such expiry date and; (b) in the opinion of Operator, another well cannot be drilled within the remaining agreement period; and (ii) the natural date of de-hiring for the contract was 30th October 2010 as per clause 1.3(a) of the contract.

(iii) To overcome the problem of delay in indent, as per recommendation of Audit, in future, all efforts would be made to prepare RRP relatively earlier. As per revised Book of Delegated Powers (BDP) and New Integrated MM Manual (applicable from 01 February 2015), administrative and financial powers of CMD, Directors, Key Executives and Corporate Rejuvenation Campaign (CRC) levels had been increased keeping in view to decentralize decision making for expediting tendering processes in an efficient manner and these changes would bring improvement in process of hiring the rigs in future tenders.

Reply is to be viewed in the context that the Company was aware, as early as in May 2010, that rig Badrinath would be available in ordinary course for drilling location D-11-A. In fact, the rig was available for more than 30 days after completing the well B-100 and could have been deployed in D-11-A without the process of de-hiring and re-hiring. However, appropriate action had not been initiated at that stage which resulted in avoidable expenditure of rig for waiting on weather for 39 days. Further, the delay on the part of the Company in initiating the re-hire process led to two precious rig months being lost which subsequently culminated in waiting on weather and consequent avoidable expenditure of ₹ 10.94 crore.

MOPNG did not offer any further comments (August 2015).

The assurance of the Company regarding corrective steps taken, would be watched in future audit.

4.3 Delay in hiring onland rigs

During 2010-14, the Company had floated nine tenders (four tenders for hiring of onland drilling rigs and five tenders for hiring work-over rigs). The Company was able to finalise only one tender (for work-over rig) within the time specified in MM Manual. The balance eight tenders were delayed, the delay ranged from 23 days to 233 days, which led to loss of 200.84 rig months (Exploration: 12.39 rig months, Development: 33.11 rig months and Work-over: 155.34 rig months) for the Company's onland operations.

Out of nine tenders scrutinised, significant delays at every stage of the tendering including indenting was noticed in five cases which are discussed below:

A. Delay in tender processing and its subsequent cancellation leading to non-availability of onland rigs

Onland Services Group (ONSG), Vadodara of the Company finalises the tenders for the onland rigs. The group received three indents for hiring drilling rigs with services between October 2010 and January 2012. The details regarding indent, invitation of tender and further processing are tabulated below:

Table 4.1: Delay in tender process for onland rigs

Asset/Basin	Indent	NIT date	Price Bid opened on	Time taken in tender process vis-à-vis-MM manual (In days)
Tripura Asset	19 October 2010 (revised thrice with last revision on 30 April 2012)	4 May 2012	8 May 2013	369 (120)
Ahmedabad Asset	2 January 2012	15 March 2012	16 July 2013	488 (120)
MBA Basin	11 August 2011	28 October 2011	17 July 2013	628 (120)

As can be seen from the table above, there was significant delay in all the three tenders. As against the norm of four months for opening the price bid from the date of NIT, the Company took more than a year in all the three cases. At the time of financial bid evaluation, the Company compared the L1 rates quoted against the estimated cost and last purchase rates. As the estimates had been made long back, the rates quoted did not match with them. Resultantly, the Company cancelled all the three tenders. Scrutiny of these tenders revealed the following:

i. In respect of Tripura Asset, the indent was repeatedly revised/modified contributing to the delay. Ahmedabad Asset furnished the indent late (in January 2012 for a rig required in July 2012). The processing of the tender for Ahmedabad was also delayed. As against 20 days for each round of clarifications from bidders, the Company took four months from August to November 2012. In MBA Basin, the tender was delayed after NIT (in October 2011) due to inconsistency in Bid Evaluation Criteria (BEC) clause and excess time taken for clarifications till January 2013. As the norm for tendering time was 160 days and that for mobilisation was 180 days, adherence to time norms would also not have made the rig available on time (July 2012).

ii. As per the circular No.23/2010 dated 9 July 2010, firms against whom banning process had been initiated were not to be issued any tender enquiry and their offers were not to be considered. M/s Shiv Vani Oil & Gas Exploration Services Limited (Shiv Vani) was banned (28 January 2013) for a period of two years and, hence, Tender Committee (TC) recommended for rejection of its offer which was approved (February 2013) by Director (T&FS). However, based on the request of M/s Shiv Vani, the Company kept on hold all the tenders invited during the period till such time (April 2013) the ban against M/s Shiv Vani was revoked by the Company and its offer became eligible for consideration. In the process, two months were lost.

iii. In July 2013, TC compared the bids vis-à-vis estimates prepared based on the purchase rate of 2009 (Ahmedabad) and 2010 (MBA Basin). TC also compared the L1 rates with purchase rates of 2010 and 2011 (Tripura Asset and MBA Basin), 2008 and 2011 (Ahmedabad Asset), concluded that the L1 rates were higher than the estimated value and recommended cancellation of all the tenders. Comparing the bids with the estimates which were three to four years old and purchase rates which were two years to five years old, without considering the effect of price escalation and without ascertaining the latest market rates did not appear to be a prudent practice. A similar issue regarding cancellation of tenders had been highlighted in paragraph 13.5.4 of C&AG's Report No. 9 of 2009-10. The Company in its ATN had stated (October 2011/September 2012) that recommendation of audit regarding vetting of estimates was noted and had assured that the cost estimates would be firmed up after factoring in all possible known variables and adequate data. However, no such action was taken in these tenders.

iv. TC recommendation for cancelling the tenders also took inordinately long to be submitted to the Executive Purchase Committee (EPC). In fact, validity of the bids had already lapsed (between July and August 2013) by the time the case was considered (September 2013) by EPC.

The delay in tendering coupled with the cancellation of tenders imprudently, resulted in non-availability of required drilling rigs. In the MBA Basin, eight shallow locations in five NELP blocks were to be drilled by 22 December 2014 as per the PSC contracts and had been planned for drilling with hired rigs (indented for in August 2011). In the absence of rigs, only one of these locations, Ladhi#1 in block PA-ONN-2005/1, had been drilled, that too by deploying a higher capacity departmental rig resulting in avoidable additional expenditure of ₹ 4.25 crore {88 days x (₹ 9.89 lakh – ₹ 5.06 lakh)}. The balance seven locations could not be drilled. In Ahmedabad Asset, the three planned exploratory wells could not be drilled over the past three years due to non-finalisation of the tender for hiring rigs. The Tripura Asset could not drill four wells planned during 2012-14 due to non-finalisation of the contract.

The Company replied (April 2015) that the delay was due to extra days for obtaining L1 approval, Director's approval, resale of tender, extension of Technical Bid Opening (TBO) at the request of the prospective bidders, seeking clarifications, legal opinions and price negotiations. The price bid opening /short-listing was put on hold as per the instructions of the then Chairman and Managing Director (CMD) on the representation of M/s Shiv Vani. The rates received against the tenders were compared with the last purchase rate and cost estimates as per the existing guidelines.

The Company also stated that the cost estimates vetted by outside consultants were higher and, therefore, the existing practice of preparing in-house cost estimates would be continued as these were reflective of market trends and also relevant to the Company's requirement.

The reply is to be viewed in the context of the following:

(i) There were inordinate delays at every stage of tender process which point to inefficiency on the part of the Company. The reasons for delay mentioned in the reply were largely controllable and could have been avoided with better planning and coordination.

(ii) The Company did not comply with its circular (issued in July 2010) which laid down that the offer of banned firms should not be considered. Despite this, the Company suspended the tender process so that the banned firm could participate.

(iii) While deliberating on the recommendation of TC to cancel the three tenders, EPC expressed displeasure on delay in submission of these cases. With the bids already invalid, EPC could not take any considered decision at that stage. Hence, EPC opined that there was no option except to close all the three tenders and to go ahead with retendering.

MOPNG stated (August 2015) that due to various rounds of clarification, further approvals and legal opinion thereon led to extended additional time taken. However, ONGC has revised delegation of powers with effect from 01 January 2015 and brought in a new integrated MM Manual with effect from 01 February 2015. As per these new company policies, administrative and financial power of CMD, Directors, Key executives etc. have been increased keeping in view the need to decentralize decision making for expediting tendering processes in an efficient manner. It is expected that these changes would bring improvement in the hiring process for future tenders. As per new MM Manual, cost estimation would be done after receipt of final forecast from the user department by set means (depending on applicability).

Audit acknowledges the corrective action taken by the Management. The effect of these actions in ensuring timely completion of the tender process would be watched in future audit.

B. Non-finalisation of tender for charter hiring of drilling rigs leading to shortage of rigs for drilling

Executive Committee (EC) approved hiring of four drilling rigs for Assam Asset in December 2011. The indent for hiring these rigs along with services was received by ONSG. Vadodara only in September 2012. In December 2012, the Company decided to modify its earlier technical condition of not accepting rigs more than 15 years old. With the modification, rigs more than 15 years could be accepted provided a residual life of five years was certified by one of the third party inspection (TPI) agencies approved by the Company. This delayed NIT for the rigs which was issued only in February 2013. On the request of a banned firm, M/s Shiv Vani, who could not purchase the tender document owing to the ban, the tender sale period was extended to 29 April 2013. Audit noticed that LOA for one rig was finally placed in February 2015. The tender for hiring the remaining three drilling rigs was still under process (April 2015).

The delay at every stage resulted in the Assam Asset not having drilling rigs even after 30 months of indenting. Due to delay/non-hiring of drilling rigs, the Asset could complete only 26 wells against the target of 31 wells planned in 2013-14 during XII FYP.

The Company stated (April 2015) that after due deliberation, modification of technical BEC clause regarding age of the rigs was approved by the Company's EC. As regards extension of sale period beyond 06 March 2013, it stated that EPC had accepted its justification in the best commercial and operational interest of the Company. Thereafter, on the request of the firm, sale of tender was again extended up to 11 April 2013, with the approval of EPC. The Company in its supplementary reply (August 2015) justified its action on extension of tender sale period during March/ April 2013 due to representation/ clarification sought by M/s. Shiv Vani (against whom banning procedure was initiated) and for change in scope of tender.

Reply of the Company needs to be viewed in the context of abnormal delay at every stage and also delay due to extension of the tender sale period twice in March/April 2013 at the request of M/s Shiv Vani, a firm against which banning procedure had already been contemplated (January 2013). Besides, the reply is silent with regard to the ten months period that elapsed between the EC approval and preparation of indent.

C. Non finalisation of tenders in time led to hiring of rigs on nomination basis

Mehsana Asset initiated (May 2012) the proposal for hiring of six work-over rigs (five 50 Ton capacity rigs plus one 100 Ton capacity rig) against the contract expiring in December 2013/ March 2014. The indent released in September 2012 was revised twice in December 2012 and March 2013 due to change in estimates and reduction in requirement (four 50 Ton and one 100 Ton). After obtaining approval of EC in July 2013, the final indent was sent to Material Management, ONSG of the Company in October 2013. The tender was floated (January 2014) and subsequently technical bids were opened in April 2014. Technical evaluation was in progress as on 12 September 2014. The contracts were finalised in November/December 2014.

Audit observed that the Asset had forwarded the first indent in September 2012 and the final indent was sent in April 2013 after seven months for approval of EC. EC took three months for approval.Thus, the Company took inordinately long time of 18 months (May 2012 to October 2013) to finalise the indent. The delay in finalisation of the tender resulted in non-availability of work-over rigs with the Mehsana Asset for nearly three years. As a result, the Company extended the existing contract on nomination basis for 50 Ton work-over rigs, with non-availability of 100 Ton work-over rig with the Asset.

The Company stated (April 2015) that as per guidelines in the existing organisational structure, hiring of rigs fall under category-B item. The requirement of all onshore work centres were sought and consolidated and the indent was placed for processing through MM, ONSG, Vadodara. The Company further stated that in the present case, after obtaining EC approval, the revised final indent, including changes in specifications and scope of work was received only in April 2013 for initiating tendering process. Thus, the delay could not be avoided and resulted in non-availability of work-over rigs in time to replace the de-hired rigs. This further necessitated hiring of rigs on nomination basis for the intermediate period to avoid operational shutdown which would have led to loss in production. The Company further stated (May 2015) that the (i) practice of obtaining EC approval was started since 2012; (ii) efforts were being made to adopt the practice of doing away with requirement of EC approval for replacement rigs to avoid delay and (iii) this would reduce the need for extending the existing rigs or hiring work-over rigs on nomination basis for the interim period. MOPNG reiterated (August 2015) the Company's reply. In supplementary reply (August 2015), the Company further added that it is also proposed to hire work-over rigs for longer period than existing practice of three years.

The assurance of the Company regarding corrective steps would be watched in audit.

4.4 Deficiencies in tendering procedure for offshore rigs

Audit scrutiny of the 23 tenders for hiring offshore rigs revealed deficiencies in four cases which are detailed below:

4.4.1 Bid evaluation criteria relaxed

An indent for charter hire of two modular work-over rigs (modular rig with Platform Supply Vessel - PSV) for Mumbai High Asset was issued in December 2011. Orders for hiring rig 'SAAG Saffron' and rig 'Nandana' was placed in January and February 2013 respectively for a firm period of three years. Both the rigs were required to be mobilised within 270 days of award. The expected mobilization of rig SAAG Saffron was October 2013 and Nandana was November 2013. Neither of the rigs had been mobilised till date (July 2015).

Audit noticed that rig SAAG Saffron was a cold stacked rig. It was built in 2007 and had been lying idle for five years (2007 to 2012) at the time of bidding (5 June 2012). Standard Bid Evaluation Condition of the Company for hiring of rigs stipulated that the bidder should offer only serviceable drilling units and idling period should not be more than 3 years on the date of submission of the bids. However, the Company relaxed this vital BEC in the tender for hiring of modular rigs. Non-mobilisation of rigs led to loss of 33 rig months upto November 2014 when the issue was noticed in audit.

The Company stated (April 2015) that since there were very limited bidders worldwide in modular rig tender, competition was low as was evident from the single successful bidder in last ten years. Competition would be further restricted if rigs lying unused for 5 to 6 years were not considered and, thus, in order to avoid restriction in competition such provision were not kept in the BEC. Further, as per the provision of the tender, the condition of the rig was certified by Company nominated TPI agency.

MOPNG stated (August 2015) that the offshore modular rig is a combination of different modules and not a unitised rig like Jack up/ floater so there was no consideration of idling period of such rigs. Further, the provision of TPI before mobilization was maintained so that there was no compromise in the scope of work and operational efficiency/ safety.

The reply is not acceptable in view of the following:

a) The decision of the Company to relax the vital standard BEC and accepting a cold stacked rig lying un-used for a long period lacks justification as it involves compromising on the quality of the rig. Besides, the relaxation of this vital standard BEC could not assure availability of the rigs as the same had not been mobilised even after a delay of over a year.

b) The contention that the standard BEC clause in a modular rig is not applicable is also incorrect. Audit noticed that the BEC clause had not been relaxed in case of Platform Modular rig (which is also a combination of different modules and not a unitised rig) from a single successful bidder.

4.4.2 Award of contract to an ineligible contractor

The Company invited (August 2012) an ICB Tender for charter hire of five 300 feet Cantilever type offshore jack up rigs to meet the requirement of Mumbai Offshore Assets for XII Five Year Plan (2012-17). M/s Jagson International Limited emerged successful bidder offering the rig Deep Sea Treasure in June 2013.

Audit scrutiny revealed the following:

- The Bid Evaluation Criteria (technical) emphasised that bids for only serviceable drilling rig could be offered. At the time of bidding, the rig Deep Sea Treasure was in Bahrain for refurbishment and modifications. The technical evaluation (March 2013) stated that the rig, having been idle since April 2010, required extensive repairs. Further, the certificate issued by TPI stated (December 2012) that equipment on the rig were not in acceptable condition and required refurbishment prior to commencement of drilling activity. Thus, serviceability of the rig was in doubt. The Tender Committee, however, awarded the contract with the assurance of the contractor that the rig would be refurbished before commencement of its operation.

- As per tender specifications, the eligible rig should have minimum power of 6,000 HP. However, rig Deep Sea Treasure had three engines with 1,950 HP capacity and, thus, had a lower power compared to the bid requirement. The bidder agreed to upgrade the power as per requirement and on this basis the contract was awarded.

The inspection of the rig was carried out in three phases after award of the contract (June 2013) for 72 days but it could not be completed. The EPC also observed (post award) that the rig did not have valid class certificate. The upgradation completion certificate approved by TPI was also not submitted.

As per contract conditions, M/s. Jagson International Limited was required to mobilize and deploy the rig along with crew and commence operations within 180 days from date of Letter of Award *i.e.*, on or before 10 December 2013. M/s Jagson failed to mobilise the rig and the mobilisation period was extended with levy of liquidated damages from December 2013 up to May 2014 five times. Finally, EPC in its meeting of May 2014 approved the termination of the contract. Accordingly, the Company terminated (May 2014) the contract with M/s Jagson with forfeiture of Performance Bank Guarantee (PBG).

Acceptance of rig, which did not meet the BEC requirements, led to non-availability of rig. This resulted in loss of more than 450 days (*i.e.* 15 rig months) and non-drilling of 13 wells planned wells during 2013-14 and 2014-15.

The Company replied (April 2015) that as per BEC clause, the bidder should offer only serviceable drilling rigs and idling period of the drilling rig should not be more than three years on the date of submission of bids. However, since the rig was not idle for more than three years, at the time of TBO (Technical Bid Opening), it was technically accepted. Moreover, there was no provision to reject the bid if idling period crosses three years at the time of award of contract. The Company also stated that the bidder had initially quoted three engines with 1,950 HP capacity against requirement of minimum power of 6,000 HP. A letter for upgrading the power of one engine to 2,100 HP was received from M/s Neptune (the authorized agency to provide spares and services). This letter was also endorsed by MODU Spec (TPI) and ABS. So there was no deviation in BEC criteria. The Company also stated that the contract of Deep Sea Treasure was terminated with forfeiture of PBG and TPI charges for entire period of inspection was recovered from M/s Jagson International Limited in the month of June 2014.

While agreeing that there was a loss of rig months, the Company stated that in order to reduce any further delay/ loss, the requirement was incorporated in the ongoing tender as soon as it was decided to terminate the agreement for Deep Sea Treasure and that it was making its best efforts to minimize the loss on this account.

MOPNG stated (August 2015) that the Company accepts the offer for any rig only after compliance of third party pre bid inspection certificate which mainly indicates the status of the drilling units. Mobilization did not include only the rig equipment but also the inventory of various items, various certification etc. as per the tender requirement. All those inventory were also checked by TPI.

The Company/MOPNG's reply needs to be viewed in the context of the following:

(i) TPI in its inspection report (September 2012) stated that most of the equipment were in unsatisfactory condition and not 'Fit for the purpose' and till its termination (June 2014) the "Fit for purpose" was pending.

(ii) Even in subsequent inspection of TPI (February 2013), it was stated that shipyard crew at the time of survey was small, overhaul/repair/certification of many of critical drilling and marine equipment were in work order stage and yet to take off.

(iii) The serviceability of the rig and rig equipment was in doubt at the time of technical evaluation (March 2013).

Eventually, the rig could not be mobilised and this resulted in loss of more than 15 rig months to the Company.

4.4.3 Banned firm allowed to bid

The Company worked out a requirement (September 2009) of one modular rig to carry out work-over operations in Neelam Heera field for the five year period (2010-11 to 2014-15). The requisition for the hiring of rig was released in December 2010 and the tender was floated in February 2011. However, the contract could be awarded only after a year in February 2012 as against the prescribed time period of 120 days. The inordinate delay in tendering process left the field without work-over rigs and the jobs were done by employing costlier jack-up rigs.

The delay in award of the contract was due to Company allowing M/s SAAG RR Infra Limited, Chennai (M/s SAAG), a banned firm (March 2010) to purchase the bid document. As M/s SAAG was not allowed in the subsequent pre-bid meeting, the firm filed (June 2011) a writ petition and the legal proceedings stayed the award of the contract for seven months. Subsequently, the case was dismissed both at High Court, Mumbai and the Supreme Court, though the Company lost precious time in the process.

Had the information regarding the banned firm been properly documented and disseminated through the Company, the purchase of the bid documents by the banned firm and consequent delay in finalisation of the contract could have been avoided. Thus, lack of proper controls in e-tendering to prevent participation of banned firm led to avoidable delay in tender finalisation.

The Company replied (April 2015) that the present tender was an ICB e-tender and there was a provision to buy tender documents online. Although M/s SAAG purchased the tender document online, they were prevented from participating in the tender process right from tender pre-bid stage itself. Even if M/s SAAG was prevented from purchase of tender document, they could still approach courts against ban order and, thus, could have delayed the tender process. Prevention of purchase of tender would not have taken away rights to seek legal intervention.

The Company also stated that as per process now being followed, ICE[9] section of the Company had incorporated a check in e-tender/SAP to restrict banned firms to even purchase tender document in the ban period. Accordingly, the Company assured that corrective measures had already been put in place to avoid recurrence of such events.

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[9] ***ICE – Information consolidation for efficiency.***

MOPNG stated (August 2015) that the assurance of the Company would be noted for compliance. The corrective action of the Company would be watched in future audit.

4.4.4 Differing standards of evaluation of bids in the same tender

In response to a tender floated in November 2009 for hiring rigs, eleven (11) bids were received. After techno-commercial evaluation, price bids of five consortia who were found to be technically and commercially acceptable were opened in April 2010.

As per BEC, in case of consortium bids, the consortium partners should individually meet the turnover limit in proportion to the percentage of work to be performed by them. In case the information contained in the 'certificate of compliance' was found to be incorrect after opening of price bids, the offer would be rejected and the bidder would be debarred for next three years.

M/s 'A1' had submitted the bid as a consortium partner with M/s 'A2'. However, M/s 'A1' did not satisfy the turnover criteria and fell short by ₹ 48.85 lakh. EPC, in its meeting held in April 2010 considered this to be a valid bid.

In evaluation of the same tender, however, the Company rejected the bid of M/s 'B1' as the average turnover of Parent Company *viz.* M/s 'B2' (the bid having been made on the strength of the parent company) was less than the threshold prescribed in the tender by ₹ 21.13 crore.

Thus, the Company took differing stands in evaluating the 'Turnover', criteria of the two bidders in the same tender. While the bid of M/s 'A1' was accepted despite lower turnover and finally emerged as the successful bidder, the bid of M/s 'B1' was rejected on similar grounds.

The Company replied (April 2015) that as per the BEC clause, M/s 'A1', the leader of the consortium was not meeting the financial criteria. However, Drilling Services (DS), Mumbai Region (MR) had opined that a method was needed to be in place in the tender to avoid complications in future tenders. M/s. 'B1' was placed at L-8 rank and considering the rigs to be hired against this tender and keeping in view their ranking, the bidder was apparently not in contention for award of contract.

MOPNG did not offer any further comments (August 2015).

The reply was to be viewed in the context that the Company used different standards in evaluating bids of two bidders in the same tender which was not an acceptable practice.

4.5 Deficiencies in managing contracts for onland rigs

Scrutiny of the 28 contracts for hiring onland rigs revealed a set of shortcomings in contract formulation and its management in two instances which are detailed below:

4.5.1 Deficiencies in rig hiring contract led to non-penalization of poor performance of contractor

Onshore Service Group (ONSG) at Vadodara entered (October 2008) into a contract with M/s Shiv Vani for charter hiring of eight drilling rigs (Two each Type-II for Tripura and Rajahmundry Assets; Three Type-III and one Type-IV for Assam Asset) with integrated services (including cementing and mud services). The rigs were deployed during 2009-12.

Audit noticed that:

(i) Non-productive time of these eight rigs was very high ~30 *per cent* (2,532 days out of 8,569 available rigs days).

(ii) An assessment of non-productive time indicated that its significant component (60 *per cent*) could be attributed to the contractor, M/s Shiv Vani. The three Assets lost 291 rig days due to repair of equipment, 391 days due to shut down of rigs for want of men and material and 842 days due to rigs being out of cycle which were attributable to poor performance of the contractor.

(iii) Rigs SVUL-2000-27, SVUL-2000-28, SVUL-2000-32, SVUL-2000-33 and SVUL-3000-50 supplied by M/s Shiv Vani remained idle mostly waiting for annular Blow Out Preventer (BOP) rubber element, waiting for choke manifold and pressure gauges, repair of Top Drive System (TDS) and fishing tools, shut down for mud cleaner screen/shale shaker screen, centrifuge, damaged high pressure hose, non-availability of drilling material, mud chemicals and cementing services with the hired rig and shortage of crew *etc.* Maintenance of all these facilities and providing necessary equipment/tools *etc.* was the responsibility of the contractor as a part of associated services with the rigs.

(iv) The contract did not include penal provision for not providing the associated services like cementing and mud services. Prolonged delays were noticed in the execution of associated services by the contractor but, owing to a deficient contract, no penalty could be imposed on it.

(v) The contractor had taken an unduly long time vis-à-vis the Company's internal norms for Inter Location Movement (ILM) and Rig Building. However, as the contract did not provide for time norms for these activities too, no penalty could be levied on the contractor. There appears to be a strong case for fixing specific time norms (with respect to distance and type of rig) for ILM and rig building in the contract to act as a deterrent against such delays.

The Company replied (April 2015) that the contractors were paid lump sum amount for ILM and, resultantly, there was no penal provision for delay in ILM. During the period of ILM, no other charges were payable to contractors. It was beneficial for the contractor to complete ILM and start the operation as early as possible so that it could get applicable day rates. However, the Company accepted that timeline for ILM had been included in current tenders for rig hiring in onshore areas, as advised by Audit.

The Company also stated that though the contract was an integrated one and included associated services like cementing and mud services, penalty clauses were limited to mobilisation of the rig alone. The Company admitted that in the instant case, there were prolonged delays in associated services provided by the contractor but these delays could not be penalised in the absence of suitable penal provisions in the contract.

MOPNG stated (August 2015) that the assurance of the Company would be noted for compliance.

Implementation of corrective action taken by the Company would be watched in future audit.

4.5.2 Improper procedure followed for termination of contract

ONSG, Vadodara awarded (February 2009) a contract to M/s Dewanchand Ramsaran Industries (P) Limited, Mumbai (contractor) for charter hire of one 2000 HP drilling rig for Frontier Basin for two years at a cost of ₹ 114.78 crore. The rig commenced operation from December 2009 at the first designated location R-BH-C of Frontier Basin with some deficiencies. In April 2010, the Frontier Basin terminated the contract for failure of the contractor to rectify these deficiencies. The Frontier Basin did not inform ONSG, Vadodara, responsible for hiring onland rigs. The contractor filed civil writ petition in the High Court of Himachal Pradesh, Shimla. The High Court (December 2010) quashed the termination of contract on the ground that the Company had not followed the prescribed procedure.

Audit observed that the Company was aware of the improper procedure of termination of the contract. Legal section, Vadodara opined that the language used in the termination letter (April 2010) was not clear and Frontier Basin should have been more careful in the matter so as to avoid any dispute and legal complications. The Chief Legal Services of the Company also noted that termination of the contract with effect from April 2010 was not in strict compliance with the procedure laid down in clauses 3.5, 3.9 and 22.5 of the contract.

The Company could not encash the performance bank guarantee of USD 863,855 and was forced to extend the contract. The Executive Committee also expressed (January 2011) deep concern over the contract management in the instant case.

The Company stated (April 2015) that the rig was hired for fulfillment of Minimum Work Programme of NELP/PEL Block which was to expire shortly at that point of time. There might have been some shortcomings in strict compliance of termination process, but rig hiring was time consuming.

The Company had agreed that there have been shortcomings in the termination process. These lapses had cost the Company in terms of forced extension of the contract and inability to encash the performance bank guarantee despite deficient services provided by the contractor. Efforts need to be taken to avoid recurrence of such incidences in future.

MOPNG assured (August 2015) that all out efforts would be made by the Company to avoid recurrence of such cases in future. Audit acknowledges the corrective action proposed.

4.6 Acquisition of rigs

4.6.1 Delay in formalizing policy for acquisition of offshore rigs

The offshore Drilling Services group of the Company had initiated a proposal for acquisition of four new jack-up offshore rigs in December 2002. The delay in acquisition of rigs was commented in Paragraph No. 4.2.4 of Performance Audit Report (No. 11 of 2012-13) on 'Hydrocarbon Exploration Efforts in ONGC' tabled in Parliament on 6 August 2012. Decision regarding acquisition of rigs was yet (May 2015) to be taken, even after 13 years.

It was seen that the Company was yet to frame its strategic policy on 'owning versus charter hiring of rigs'. Meanwhile, most of the Company's owned rigs had outlived their useful lives of 30 years. In case the Company does not take a decision on acquisition of rigs early, it may have to be entirely dependent on CH rigs in near future.

In response, the Company stated (April 2015) that a high level Committee in association with a consultant - M/s McKinsey was constituted to evaluate business model of own versus CH drilling rigs for both onshore and offshore operations. The Committee had submitted (March 2014) its report to EC. After finalisation of the ownership policy of onshore and offshore rigs, further action in this regard would be decided. The Company accepted that considerable time had lapsed in finalisation of the decision. However, it had been stressed that such investment decision for acquiring capital assets worth around ₹ 5,000 crore needed thorough evaluation.

Table 4.2
Vintage of owned rigs

Rig	Mfg. Year	Vintage
Jack-up Rigs		
S/Gaurav	1982	33 years
S/Shakti	1982	33 years
S/Jyoti	1983	32 years
S/Ratna	1985	30 years
S/Kiran	1988	27 years
S/Uday	1990	25 years
Drillships		
S/Vjiay	1985	30 years
S/Bhushan	1987	28 years

While seriousness of the investment decision was appreciated, it was pertinent to note that four out of six jack up rigs had outlived their economic lives of 30 years as determined by the Company. The two drillships *viz.* Sagar Vijay and Sagar Bhushan had also outlived their prescribed economic life of 25 years. The Company had highlighted (October 2013) the importance of having a mix of own and chartered hire rigs for a competitive edge. Considering the age, huge cost of major lay-up repairs and poor performance of the owned offshore rigs, the Company needed to decide its policy for owning versus hiring of rigs which has been pending for the last 13 years.

MOPNG stated (August 2015) that most of the offshore rigs owned by the Company had outlived their useful lives and a policy regarding acquisition of rigs would be finalised by the Company expeditiously. Any acquisition would be done after finalisation of ownership policy.

The formulation and implementation of 'rig acquisition policy' as assured by MOPNG would be watched in future audit.

4.6.2 Non-acquisition of five onland mobile drilling rigs

A review of the acquisition of onland rigs over 2010-14 indicated lack of firm policy in this regard. The Executive Committee (EC) of the Company had approved (July 2006) purchase of ten onland drilling rigs (six Type-III, 2000 HP and four mobile drilling rigs of 700 HP). Purchase of all the ten rigs had a negative NPV. The Board, however, approved (August 2011) the procurement of only six Type-III-2000 HP drilling rigs fitted with AC-VFD[10] from M/s. BHEL on nomination basis at a cost of ₹ 795.72 crore.

The requirement of mobile rigs had meanwhile increased to five. The Project Appraisal Committee (PAC) in its 105[th] meeting held in April 2011 observed the need to establish

[10] ***Alternative Current Variable Frequency Drive.***

reasonability of procurement of mobile rigs from M/s. BHEL on nomination basis in view of

the negative NPV reflected in the appraisal. The Board (August 2011) recommended ICB tender for procurement of mobile rigs.

Subsequently, EC reviewed (June 2013) the economics of the procurement against hiring of the onland rigs and observed that procurement would lead to negative NPV considering eight *per cent* escalation of hiring charges per annum. The acquisition would yield a positive NPV only if the escalation of hiring charges was considered to be 12 *per cent* per annum. On this basis, EC accorded in principle approval for acquisition of the five mobile drilling rigs. In the same meeting, however, EC directed that no purchase of new rigs or renovation /upgradation of existing onland rigs be taken up unless the revised onland rig discard policy was firmed up. Accordingly, the proposed procurement action of five mobile drilling rigs was not pursued further.

Audit observed that:

i. The decision regarding procurement of onland rigs had not been consistent. While six AC-VFD drilling rigs were procured (2012) despite negative NPV and lack of rig discard policy, five mobile rigs were not procured on the same ground. The five rigs were required for replacing existing rigs already laid off/ proposed to be laid off and, therefore, the decision affected availability of mobile rigs.

ii. With the hiring process of mobile rigs also getting delayed, the Company faced a shortage of mobile rigs. In Mehsana Asset, two rigs of the Asset had already been laid off. Similarly, Tripura Asset was facing shortage of rigs to meet the target of providing 6.0 MMSCMD of gas to ONGC Tripura Power Limited (OTPL) and Ahmedabad Asset faces difficulty in meeting targets of Exploratory Drilling.

The Company stated (March 2015) that the decision in this regard was pending finalisation of policy on mix of owned versus hired rigs.

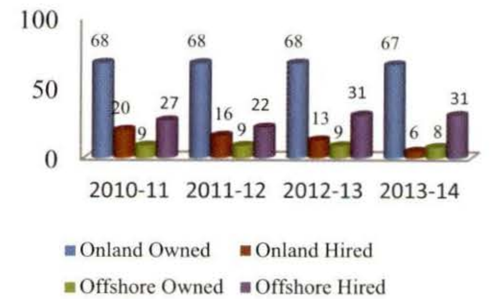
MOPNG stated (August 2015) that discard policy has been approved and rig acquisition process has been initiated, which would be put up to EC within fifteen days. Based on EC decision, the timeline for acquisition would be decided in a phased manner depending upon the number of rigs getting discarded by third party inspection. As regards the tendering process, the Company had revised delegation of powers (January 2015) and brought in a New integrated MM manual (February 2015) and these new policies, decentralized administrative and financial powers would expedite tendering process in an efficient manner for future tenders.

The timely implementation of rig discard policy, acquisition of new rigs in place of discarded old rigs and benefits of revised delegation of powers and new integrated MM manual policies in expediting tendering would be watched in future audit.

Chapter 5: Deployment of Rigs

The Company deploys rigs (both owned and hired) for drilling operations as per the annual deployment plan and conditions specified in the service level agreements (SLA) signed with Drilling Services group. As on March 2014, the Company owned 67 onland drilling rigs and eight offshore rigs. The chart alongside shows the number of rigs under the Company's operation during the period from 2010-11 to 2013-14. As can be seen from the chart alongside, the majority of rigs deployed by the Company in onland areas were owned while in offshore the bulk of the requirement was hired.

Chart 5.1 Owned and Hired Rigs



5.1 Significant deviation from rig deployment plan

The year-wise details of exploration and development wells planned in offshore and onland areas in the Rig Deployment Plans (BE and RE) and the actual wells drilled during 2010-14 is given in ***Annexure II***. Comparison of wells planned in the annual RDP against the actual wells drilled revealed that wells planned in RDP (BE) were often not retained in the RDP (RE) and the actual locations drilled were significantly different from both the plans. It can be observed from the Annexure that out of 1,867 wells drilled both in onland and offshore areas during 2010-14, 615 wells (~ one third) were not planned even in the revised RDPs for these years.

This rendered the elaborate exercise of planning annually for budgetary and revised estimates ineffective.

While accepting the observation of Audit, the Company stated (April 2015) that rig deployment needs to be frequently reviewed and may get changed as per actual conditions *i.e.* requirement of early Asset oil gain, availability of ready location due to land acquisition and environment constraints *etc.* Rig was deployed on suitable locations that were ready for drilling at the time of rig release keeping in view the priorities of Assets/Basins. The Company assured that further efforts would be made to minimise changes in plan though it may not be possible to ensure that there was no deviation from RDP while drilling. While reiterating the above, MOPNG stated (August 2015) that as advised by Audit, further efforts would be made to minimize changes in plan by proper planning and coordination among Assets/Basins and Services.

While Audit agrees that some amount of deviation and changes from the plan may occur due to the factors brought out by the Company, the frequency and extent of change from plan to actual indicates deficient planning. The assurance of the MOPNG/Management of the Company would be watched in future audit.

5.1.1 Case study of plan versus actual drilling in shallow water areas

A. Shallow water exploration areas

During 2010-14, 100 shallow water exploration locations were drilled against the 146 locations planned in the revised estimates of RDP. There was, thus, a shortfall of 33 *per cent* in actual drilling vis-à-vis targets. The locations that were drilled were also not as per plan. Of the 100 locations drilled, 26 were as per original RDP, 57 were as per revised RDP and the remaining 17 were the wells that had not been planned at all.

Of the 46 locations that had been planned in the RDP but were not drilled, majority (35) were on account of the following:

- In 16 cases, the rig was un-available due to delay in hiring;
- In 9 cases, rigs that had been assigned to the location were out of cycle due to delay in repairs; and
- In 10 cases, the rigs allocated to the locations were diverted to development wells.

While accepting the observation of Audit, the Company replied (April 2015) that there was a continuous review process by the exploration group which decides the priority of the location to be taken up based on various factors, such as MWP deadlines, re-assessment of sub-surface based on recently drilled wells, *etc.* in which the new locations were taken up subject to the rig-time availability and some locations were carried forward to next years' revised estimate (RE). At times, planned wells had to be dropped and unplanned wells drilled in view of the urgent prioritisation by exploration team.

In supplementary reply post Exit Conference (August 2015), the Company stated that in most of the tenders the availability of rigs were less than the tendered quantity and the shortage of rig months due to non-availability of chartered hired rigs leads to re-alignment of rigs between exploratory and development locations. The Company assured that efforts would be made to deploy the rigs as per exploratory/ development plans.

The Company's reply is not acceptable as in the instant case, the locations could not be drilled mainly on account of avoidable factors like delay in hiring, delay in repair of owned rigs and diversion of rigs from exploration to development activities and, thus, the difference between plan and actual drilling of wells was not largely due to re-prioritisation by the exploration group. These factors could have been addressed by the Company by proper planning, co-ordination and efficiency. Besides, out of 17 tenders (including re-tenders) the Company could get tendered number of rigs or more in 11 tenders and, thus, availability of tendered quantity does not appear to be a serious problem. However, the assurance of the Company would be watched in future audit.

MOPNG did not offer (August 2015) any comments.

B. Shallow water development areas

The Company planned drilling a total 193 wells during 2010-14 as per FYPs in Mumbai High Asset, against which it had planned 152 wells in the Annual Plans. The Company drilled only 127 wells during the same period. The shortfall in drilling in number of wells was mainly due to:

- Delay in installation of the new platforms N17, N18 and N20 in 2011-12;
- Dropping of drilling in WO-16 due to delay in Mobile Offshore Production Unit (MOPU) in 2013-14;
- Drilling of one well in RS-4 platform due to non-availability of rig; and
- Dropping of two wells at IT platform as movement of rig was not possible due to laying of pipeline in the area in 2013-14.

As most of the wells drilled were not even as per Revised Estimates plan, such deviations were only indicative of deficient planning. Frequent changes in drilling plans stressed scarce rig resources by way of additional rig movements and cascading effect on drilling operations by way of non-achievement of plan targets.

The Company stated (April 2015) that rig deployment for each rig was deliberated in detail in Asset Joint Operation Review meetings and after approval of Assets only, these plans were being finalised. However, number of actual wells drilled was dependent upon RFD (Ready for Drilling) status of new platforms and priority of Assets for particular platform at the time of drilling. Any change in rig deployment was approved by concerned Asset/Basin manager after due diligence. As per recent EC decision, Bar Chart would be prepared and subsequently approved in SAP system from pool of released locations for rig deployment. Any variance in this regard would require approval of competent authority. The Company stated that it was making all efforts to improve the system. MOPNG added (August 2015) that the assurance of the Company would be noted for compliance.

The action taken would be watched in future audit.

5.2 Rigs remaining out of cycle for extended periods

As per the Service Level Agreement (SLA) signed by the Drilling Services group (service provider) with the Assets/Basins (user) during 2010-14, rig utilisation was to be 95 *per cent* for owned rigs and 100 *per cent* for CH rigs. Owned and CH rigs in the Company remained out of cycle[11] for prolonged periods leading to a much lower actual rig availability at 87 to 91 *per cent* vis-à-vis the SLA. Of the total 5,600 rig months available during 2010-14, 679 rig months (478 rig months in onland area and 201 rig months in offshore area) accounting for 12 *per cent* of the available time, were lost due to the rigs remaining out of cycle.

[11] ***A rig is termed as 'out of cycle' when it is not available for drilling due to capital repairs, refurbishment, dry dock, third party inspection for fitness or waiting on weather, bandh and barricade.***

Table 5.1: Rig out of cycle

Year	Area	Total rig months available	Rig months for which rigs remained out of cycle	Percentage of out of cycle over total available rig months
		A	B	
2010-11	Onland	1,019	118	12
	Offshore	404	41	10
2011-12	Onland	1,029	113	11
	Offshore	386	45	12
2012-13	Onland	977	135	14
	Offshore	440	73	17
2013-14	Onland	887	112	13
	Offshore	458	42	9
Total		**5,600**	**679**	**12**

An analysis of the out of cycle period indicates that the primary reason was capital repairs and refurbishment of the rigs as shown in the charts below:

Chart 5.2: Offshore Rig months lost

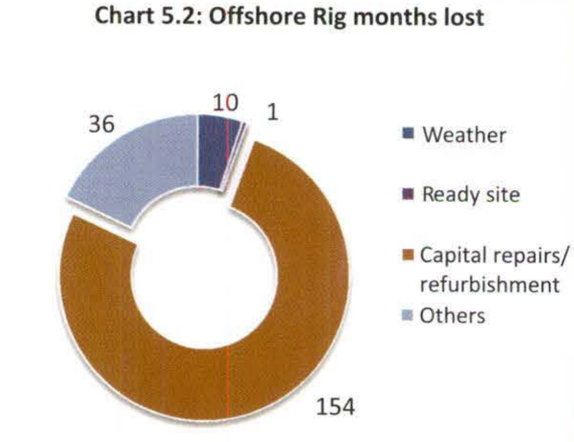
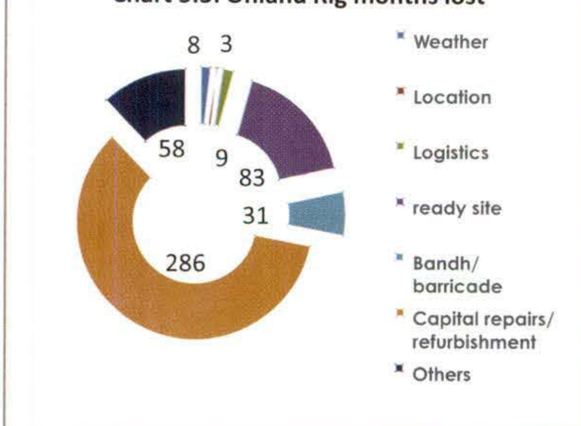


Chart 5.3: Onland Rig months lost



Capital repair and refurbishment of rigs constitute 53 to 75 *per cent* (offshore rigs: 48-91 *per cent* and onland rigs: 46-70 *per cent*) of the total out of cycle period of the rigs. For offshore owned rigs, the time lost in rig being out of cycle was particularly high.

The Company stated (April 2015) that, in offshore areas, some components of rig structure like hull, legs, spud-cans *etc.* sometimes get damaged during rig moves and their repair requires rig to remain out of operation for longer durations. These types of repairs were normally unexpected and, hence, arranging manpower, material and services required for repairing also needed some time. Charter hired rigs were out of cycle mainly due to accidental repair requirement/statutory obligations necessary for fitness of rig. The Company added that all out efforts were being made to maintain the rig equipment in proper running condition by carrying out timely preventive maintenance but breakdown of equipment was unavoidable, as with any other machine(s). Offshore rigs were working in highly corrosive marine environment. Hence, repairs related to corrosion, like refurbishment, was more in offshore. With regard to onland areas, the Company stated the rigs were out of cycle for want of ready sites (*i.e.* 10.9 *per cent)* mainly due to land acquisition, local issues and statutory clearances.

MOPNG stated (August 2015) that the Company is planning the dry dock of rigs in a phased manner and proceeding with aggressive manpower recruitment. During Exit Conference (August 2015), the Director (Technical & Field Services) of the Company also stated that once the old departmental rigs were refurbished/ repaired/replaced, the out of cycle percentage would reduce. In the supplementary reply (August 2015) the Company added that charter hire rigs are carrying out planned repairs during the intervening period from de-hiring of the rig to deployment in a new contract. All efforts are made to minimize the out of cycle period for the departmental rigs by taking up only those repair activities which cannot be handled simultaneously during rig operations.

The reply of the Company/ MOPNG needs to be viewed in the following context:

a) The Company's contention that the repairs were un-expected owing to corrosion in marine environments was not correct. A significant reason for rigs remaining out of cycle was that the rigs were old, major lay-up repairs/ up-gradation of owned rigs had been neglected and equipment replacement policy had not been adhered to. These factors contributed to breakdown of equipment, especially of mud pumps/ draw works as commented in Chapter 6 - Paragraphs 6.1.1, 6.1.3 and 6.3. In addition, the internal monitoring of the Company had cited, *inter-alia*, inadequate manning of rigs and aged manpower adversely affecting drilling performance. In case of onland rigs, repairs were also the largest contributor to rigs remaining out of cycle.

b) The Company inordinately delayed the formulation of major lay-up repair policy and the policy had not been adhered to. Due to this, departmental rigs were continuously deployed for offshore operation which deteriorated their condition further and led to extended out of cycle periods.Though in the recent past, recruitment efforts had been initiated, the present manpower position was not commensurate with the requirement of skilled manpower.

The adherence to the major layup repairs policy and the impact of efforts to reduce 'out of cycle' of own rigs would be watched in future audit.

5.2.1 Financial impact of rigs remaining out of cycle

The rigs remained out of cycle for 12 *per cent* of the available rig time and, thus, could not be deployed on development and exploration activities. It cost the Company ₹ 2,375 crore during 2010-14. As per Corporate guidelines, the Company did not allocate this cost to Assets and Basins and charged the same to Profit/Loss of the respective year. Besides, absorbing the cost of rigs remaining out of cycle, the Company lost 679 rig months due to non-availability of the rigs.

Western Offshore area, where the highest number of jack up rigs (22 rigs) were deployed for development and exploratory activities, had charged off ₹ 517 crore towards expenditure incurred on rigs remaining out of cycle during 2010-14. It was observed that 78 *per cent* of rig out of cycle cost *i.e.* ₹ 403 crore, pertained to owned rigs. The out of cycle cost charged off for the seven owned rigs ranged from ₹ 21 crore to ₹ 114 crore. The rigs Sagar Shakti (₹ 114 crore) and Sagar Jyoti (₹ 72 crore) accounted for the most significant out of cycle costs in western offshore. It is pertinent to mention that both the rigs were long overdue for lay-up repairs/dry dock. In comparison, loss due to the 15 charter hired rigs remaining out of cycle was lower at ₹ 114 crore, the per rig cost ranging between ₹ 1 crore to ₹ 21 crore.

MOPNG confirmed (August 2015) the facts, though it did not offer any comments. The Company stated in its supplementary reply (August 2015) that taking rigs out of cycle cannot be avoided totally as per the requirements of planned/ emergent repairs.

The reply of the Company needs to be viewed in the context of abnormal out of cycle hours of the owned rigs which could be attributed largely to delay in formulation of major lay-up policy and non-conformation to the major lay-up repair policy/ equipment replacement policy, and ought to have been addressed by the Company.

5.3 Rigs deployed, but remained idle

In addition to rigs remaining out of cycle and the related cost not being allocated to the cost of exploratory and development wells, rigs remained idle for considerable periods even after being deployed for drilling. This idle time of deployed rigs was termed Non Productive Time (NPT) and its cost was treated as an expenditure of the respective Assets and Basins where the rig was deployed (expenditure being capitalised for all Assets and successful drilling efforts in Basins). Idling of rigs leads to lower utilisable rig months and also increases the drilling cost. Minimising NPT was, thus, the cornerstone of efficient rig utilisation and drilling operations.

NPT arising out of rig waiting for weather and day-light was non-controllable. The balance NPT was defined as controllable. The controllable NPT was segregated into 'operational' and 'non-operational'. 'Operational' NPT was on account of complications in drilling, such as stuck up/fishing/side tracking, mud loss activity, down-hole tool failure, logging tool failure *etc.* The 'non-operational' NPT of rig was on account of rig waiting for man/materials/log tool, instructions, logistics and repairs. 'Operational' NPT can be addressed by better technology and skill in drilling assignments. 'Non-operational' NPT also often leads to complications and adds to 'operational' NPT. It may, however, be difficult to substantially eliminate such operational NPT, particularly in complicated drilling assignments. 'Non-operational' NPT, on the other hand, can be eliminated with better planning and co-ordination within the organisation.

NPT of the Company, segregated into operational and non-operational NPT for the period 2010-14, is tabulated below:

Table 5.2: Non-Productive Time (NPT) of rigs

Year	Total drilling time (Rig months)	NPT (Rig months)	NPT as a percentage of total drilling time	Percentage of operational NPT	Percentage of non-operational NPT
2010-11	778	179	23.01	15.17	7.84
2011-12	790	182	23.04	15.95	7.09
2012-13	782	161	20.59	11.89	8.70
2013-14	741	143	19.30	10.80	8.50

Source: Annual Report of Director (T&FS) report 2010-14

As can be seen from the table, NPT of the rigs (both owned and CH rigs) during the period 2010-14 was considerably high ranging between 19 to 23 *per cent* in comparison to the benchmark of 5 to 12 *per cent* used by the international consultants, engaged by the Company, to analyse the offshore drilling performance. It was also seen that while the overall NPT was on a decline, the non-operational NPT had steadily increased over this period (2010-14). During 2010-14, controllable NPT of rigs cost the Company ₹ 6,418 crore (₹ 3,782 crore in shallow water area, ₹ 1,748 crore in deep water area and ₹ 888 crore in onland area).

5.3.1 NPT in offshore areas

In offshore areas, rigs remained idle (NPT) for 26.16 *per cent* to 28.72 *per cent* of the time during 2010-14. This was considerably higher than the benchmark of 5 to 12 *per cent* used by international consultants engaged by the Company to analyze its offshore drilling performance (2009). Considering the efficiency enhancing measures employed by the Company during 2010-14 including advance mud systems, new generation bits and new technologies, the high level of NPT was a matter of concern for the Company. What was significant was that the non-operational NPT which was entirely controllable by the Company through better planning and co-ordination was on the rise as shown in the adjoining chart.

The high NPT of rigs had been commented in the earlier audit reports of C&AG[12]. In response, the Company had assured that corrective action would be taken to avoid controllable delays. It was seen that the issue of higher NPT in the Company was discussed at various fora in the Company as well as in MOPNG. However, NPT during 2010-14 remained at a consistent high of 26.16 *per cent* to 28.72 *per cent* as against NPT of 22 to 31 *per cent* during 2007-11.

The Company in reply stated (April 2015) that there were no international standards for NPT and worldwide NPT for complicated wells were usually in the range of 30 *per cent*. Petrobras, one of the biggest operators, plans for 40 *per cent* NPT for drilling its deep-water wells. The Company further stated that NPT was dependent on well complications/fishing, waiting/ shutdown and repairs and that efforts were being made by Drilling Services group to contain NPT by induction of advanced technologies, strengthening logistics and shore based facilities and induction of new rigs.

[12] ***Paragraph no. 7.7.3.4 & 7.7.3.5 of Report No. 9 of 2007 on 'Performance of offshore rigs in shallow water areas of ONGC', Paragraph No. 8.7.3.4 of Report No. 10 of 2010-11 on Performance Audit of 'Exploration in Shallow water Blocks of ONGC' and Paragraph No. 4.2.2 of Report No. 11 of 2013 on Performance Audit of 'Hydrocarbon Exploration efforts of ONGC'.***

MOPNG in its reply stated (August 2015) that though all wells in offshore area are not deep water, it is prudent to mention that in shallow water wells, down-hole complications happen due to mud loss/ well activity/ stuck up etc. as most of these wells are drilled in depleted reservoir. New technologies are introduced to minimise down-hole complications. As advised by Audit, efforts are being made to contain NPT due to non-operational factors by strengthening logistics and shore base facilities.

During the Exit Conference (August 2015), the Company agreed with the audit view and stated that non-operational NPT is a matter of concern for the Management and assured that it would be addressed.

The Company in supplementary reply (August 2015) stated that to address the non-operational NPT, more vessels are being hired and two more supply bases are being set up nearer to the fields. This would have a positive effect in reducing the NPT due to waiting for logistics and supplies. The aggressive manpower recruitment is in place to address the issue of ageing and shortage of manpower.

The reply of MOPNG/ Company highlights complicated and deep water wells. However, all wells in offshore area were neither deep water nor complicated. Deep water wells in offshore areas accounted for only 13.5 *per cent* of the total offshore wells. Considering the benchmark NPT of 5 to 12 *per cent* considered by the consultant appointed by the Company, the 26 to 29 *per cent* NPT was a matter of concern. Moreover, a significant component of NPT in offshore areas was on account of non-operational factors, logistics, manpower, *etc.* which though entirely controllable by the Company was steadily on the rise.

Audit acknowledges the corrective action initiated by the Management. The compliance of the above would be watched in future audit.

5.3.1.1 Financial impact of NPT in offshore areas

Idling of rigs not only leads to lower rig availability for drilling in the Assets and Basins, but was also associated with a financial cost. To appreciate the financial impact of NPT in offshore areas, the shallow water drilling in Mumbai offshore and drilling in deep water areas were scrutinised.

A. NPT of jack up rigs in Mumbai offshore

The financial impact of controllable NPT of jack-up rigs in Mumbai offshore over 2010-14 was ₹ 3,782 crore along with a loss of 211 rig months. Of this, operational NPT accounted for 60 *per cent* (financial impact ₹ 2,268 crore) and non-operational NPT was 40 *per cent* (financial impact ₹ 1,514 crore). A significant reason for NPT was repair and refurbishment of owned rigs. A comparison of NPT of owned and CH rigs revealed that owned rigs remained under repair for a significant 24 to 42 *per cent* of their NPT (and the repair period as a percentage of NPT was on the rise) as against 7 to 9 *per cent* for CH rigs during the period 2010-14. MOPNG confirmed (August 2015) the facts, though no further comments were offered.

B. NPT of deep water drilling rigs

The Company had deployed only CH drilling rigs for drilling deep water wells. During the period from 2010-14, six[13] rigs had been deployed by Deep Water group of the Company for its operations in East Coast and West Coast and the controllable NPT had been steadily on the rise from 12.82 *per cent* in 2010-11 to 27.03 *per cent* in 2013-14. Of the total controllable NPT of 1,083 rig days (during 2010-14), 51 *per cent* accounting for 554 days were on account of breakdown of various rig equipment. The balance controllable delays (~41 *per cent*) were due to well complications. The total extra expenditure to the Company due to controllable NPT, excluding period of rig break-down worked out to ₹ 1,748 crore during this period. Though the Company did not pay the contractor for the period, the rigs were under break-down (554 rig days), the associated services (e.g., well engineering, well testing services, *etc.*) had to be paid for, though the same also remained idle. A case in point was the deep water rig GSF 140 hired for drilling five wells over a period of two years against which only two locations could actually be drilled. The planned *versus* actual days and cost of these two wells was tabulated below:

Table 5.3: Planned and actual days and costs of drilling of wells by Rig GSF 140

Well No.	Planned days	Actual days	Estimated cost	Actual cost
G-18-1 (AA)	201	389.58	US $ 41.15 million	US $ 167.98 million
KG-DWN-98/2 - KT-2	175	445.6	US $ 109.47 million	US $ 201.56 million

A review of the rig operations revealed that the equipment break-down period (rig break-down) during drilling of wells G-18-1 and KT-2 was 115 days (29 *per cent* of total days utilised) and 90 days (20 *per cent* of total days utilised) respectively which resulted in loss of 6.83 rig months. Though the contractor had not been paid for the period the rig was under break-down, the Company had to make a payment of US$ 22.32 million approx. on three associated services *viz.* bundled services, well engineering, well testing services hired for the rig GSF-140, even though no service was delivered as the rig remained idle.

The Company in its reply stated (April 2015) that the sharp increase of NPT from 2010-11 to 2011-12 was due to increase in complications encountered during drilling, attributed mainly to challenges faced in exploratory drilling of deep wells for the first time in Mahanadi Basin and Andaman Basin. This trend continued in following years 2012-13 and 2013-14 when two extreme high pressure high temperature (HPHT) wells were taken up for the first time. As the deep water group ventures into new areas for drilling, it was associated with high risk of drilling surprises and new challenges *e.g.* HPHT wells, narrow window between pore pressure and fracture pressure gradient, mud loss *etc.* The Company also stated that complications in deep water drilling and HPHT wells had been a global phenomenon in the oil and gas industry and, therefore, the marginal increase in NPT in past few years needed to be viewed in line with the difficult and challenging task of deep-water drilling. The Company also stated that the performance of rig GSF-140 had not been good in the initial period of contract and, hence, the rig contractor was issued numerous warning letters to improve performance. Accordingly, the contractor mobilized additional equipment and subsea experts which resulted in gradual improvement on rig NPT. The Company also highlighted the fact

[13] ***(1) Discoverer Seven Seas; (2) DDKG-1; (3) Platinum Explorer; (4) M G Hulme Jr.; (5) GSF-140 and (6) GSF Explorer.***

that the majority of rig NPT was attributed only to repair of subsea 'blow out preventer' (BOP) and as the rig was deployed for drilling HPHT wells, basic well control equipment were needed to be kept in *cent per cent* working condition for safety of men and material. The Company added that the payments made for associated services were in line with contract provisions.

Reply of the Company that rig breakdown was a primary cause for NPT needs to be viewed in light of the fact that these rigs had been hired by the Company after technical due diligence. It was noticed that high rig breakdown had been seen in two of the six rigs hired, GSF 140 and GSF Explorer (~24 *per cent* of the rig hours of these two rigs were lost due to breakdown) while in the other four rigs, the break-down component was low at 2.59 to 5.81 *per cent*. While the Company's response regarding higher complications in deep water wells was appreciated, the steady increase of NPT in deep-water drilling was a matter of concern and needs to be addressed through better technical capacity and efficiency. While the rigs remained idle, the associated services though unutilised continued to be paid, which added to the overhead cost of the wells. The Company may consider incorporating a suitable clause for interruption free operation of the rig through proper maintenance and non-admissibility of payment of associated services in the contract in case rig remained idle due to break-down of rig or other reasons attributable to contractor. Besides, with the high NPT, the Company could not achieve its planned programme in deep water drilling (as against a target of drilling 63 wells, the Company could only drill 48 wells).

MOPNG stated (August 2015) that incorporating a clause for non-admissibility of associated services payment in case of rig equipment break down would not be proper as both the contracts are independent and in line with industry practices. During Exit Conference (August 2015) the Company added that additional stipulations would lead to increased contract value as the contractors would load the bid based on their risk perception. However, the Management assured that the matter would be considered by the Company.

The action taken by the Company to protect its financial interests in future contracts would be watched in audit.

5.3.1.2 Specific cases of idling of rigs (NPT) in offshore areas

Over the period 2010-14, 49 offshore rigs had been deployed by the Company. The deployment of a sample of 23 rigs was scrutinised in audit and the results are given below. While the rigs remained idle waiting for ready sites, facilities remained idle for want of deployment of rigs. In Mumbai offshore Asset, the facilities of 21 platforms were ready for drilling (2010-14) but rigs had not been deployed and the platforms remained idle for upto 777 days. The delay in commencement of drilling resulted in idling of facilities and deferment of production valuing ₹ 4,003 crore (approx.) for oil and ₹ 1,174 crore (approx.) for gas.

The Company replied (April 2015) that rigs were hired based on workload provided by Basin/Assets and deployed as per their requirement. This highlights the need for better coordination to avoid idling of rigs or facilities.

A Idling of rigs due to non-availability of ready platforms

A review of rig deployment plan versus actual deployment of drilling units in Mumbai offshore development area during 2010-14 revealed instances of the rig being moved to the platforms (locations) even though the platforms were not ready to take up the drilling activity or the location had not been approved for drilling. This resulted in loss of precious rig months and led to unfruitful expenditure of ₹ 19.51 crore. The individual instances noticed are as below:

a. The rig, Ran Top Mayer (RTM) waited for readiness of N-20 platform from 01 May 2011 to 15 May 2011. Thereafter, as the platform was still not ready for drilling, the rig was shifted for deployment at an alternate location, RS-17. However, the rig RTM could not be docked at RS-17 as a barge was working near the platform (till 21 May2011) and due to rapidly worsening weather. The rig RTM was finally deployed at exploratory location SB-J. In the process, the rig RTM had idled for 20 days, costing the Company ₹ 5.54 crore.

b. The rig GD Chitra had to wait at N-14 platform as construction activity was in progress and the top deck of the platform was full of construction material. The rig waited at the platform for 23 days from 29 April 2011 to 21 May 2011, the idling cost amounting to ₹ 13.97 crore.

In both the cases, idling of the rigs could have been avoided by better planning and co-ordination within the Company. The status of the platform ought to have been confirmed before moving the rig to location which led to idling of precious resources.

The Company stated (April 2015) that rig deployment on new platforms was planned well in advance based on RFD (Ready for Drilling) dates. However, in some cases RFD of platforms get delayed. When this delay was significant, the rig deployment plan was modified so that rig can be moved to alternate locations in order to avoid idling of rigs. However, in some cases RFD of the platforms gets delayed only marginally and was expected to be complete by the time rig was ready for movement. But the platform does not get completed and then the rig may have to wait depending on the priority of the wells on the platform, as informed by the Asset. In such cases, if rigs were deployed at any other platform with lesser gain expectations then it might have resulted in reduction in expected production and revenue and it can affect incremental gain planned by the Assets.

The reply of the Company was not convincing. Idling of rigs for 21- 25 days at a stretch as the platform was not ready, cannot be termed as insignificant considering the high rig hire charges. Besides, idling of the rigs could have been avoided with better co-ordination between the Engineering Services group (responsible for the platforms) and the Drilling Services group (responsible for deploying the rigs) of the Company. It was also noticed in audit that the rigs, RTM and GD Chitra were shifted to un-planned locations after waiting for a considerable period which highlights the inefficiencies in planning for precious rig resources.

MOPNG in its reply stated (August 2015) that as advised by Audit, more efforts would be made in planning and co-ordination within the Company to avoid any idling of rigs.

B. Indecision in deployment led to additional expenditure and rig movement

The rig, Noble Kenneth Delaney (Noble KD), had been planned to be deployed at platform B-193A to drill five development wells in monsoon, 2012-13. The rig waited at location for sea bed survey from 09-12 April 2012. Subsequently, the rig was moved to well no. NM#4 from 13 April 2012 for work-over operation. On the basis of a message received from Mumbai High Asset, the rig was moved back to platform B-193A on 26 April 2012, without completing the work-over job. The rig was again kept waiting for sea bed survey from 27-29 April 2012 at B-193A platform. As the work-over job had not been completed, another rig, JT Angel had to be deployed to well NM#4 from 12 October 2012.

On account of indecision in rig deployment, the Company incurred additional expenditure of ₹ 10.61 crore, as shown below:

- ₹ 4.70 crore on deployment of rig from 13 April 2012 to 26 April 2012;
- ₹ 2.17 crore on rig waiting for sea bed survey;
- ₹ 1.20 crore on additional rig move; and
- ₹ 2.54 crore on overheads.

The Company in its reply (April 2015) confirmed that Rig Noble KD was planned to be deployed at platform B-193A to drill five development wells in monsoon. However, the platform was not ready by the time the rig was ready to move.

The reply highlights the lack of co-ordination as the Company could have deployed the rig to ready locations idling for want of rigs instead of deploying the rig to work-over jobs.

MOPNG stated (August 2015) that the audit concern is noted to prevent recurrence of such cases in future.

C. Rig idled during monsoon leading to unfruitful expenditure of ₹ 90.57 crore

The rig Aban Ice had been allocated to well GSS041NAA-1 in January 2011 (the well was spud on 19 January 2011) and was on the well location during the onset of monsoon. Suitable steps for enabling usage of the rig (by suitable anchoring *etc.*) during the monsoon season was not taken by the Company and the rig idled on location for four and a half months. As per the time balance report, the rig status from 11 May 2011 to 24 September 2011 read *"Change rig heading to Monsoon Heading"*[14] and the drilling status remained at a constant 3,803 metres throughout the entire period indicating that necessary steps for changing the rig heading had not been taken leading to idling of the rig throughout the monsoon season. The drilling was resumed on 25 September 2011 and completed by 21 February 2012 when the rig was finally released from the location. During the monsoon period, as the rig idled, the Company incurred an unfruitful expenditure of ₹ 90.57 crore.

[14] ***Change of rig heading: Rig Heading is an orientation of drillship/ jack up rig positioned at a location to accommodate the adverse weather conditions such as cyclonic winds and underwater currents. During monsoon, rig heading was changed to ensure smooth operation. This was done so that the disposition of the rig was optimal considering the monsoon specific environmental conditions.***

Audit also noticed that in another well D-11-A, the Company had taken suitable steps to change the rig heading to monsoon for rig Badrinath deployed on the well. In fact, the job for changing the rig heading had started on 22 April 2011 and the rig commenced further drilling from 09 May 2011. Similar action ought to have been taken in the case of rig Aban Ice thereby avoiding the unfruitful expenditure of ₹ 90.57 crore. In case of difficulty in continuing drilling at the same location during monsoon, the Company could have temporarily abandoned the well and taken up another monsoon location for drilling and continued drilling on this location post monsoon(as was the practice). Lack of prompt action on the part of the Company led to idling of the rig, loss of precious rig months and unfruitful expenditure.

The Company stated (April 2015) that the decision to change the rig heading was timely and appropriate, but the change of rig heading of Aban Ice got delayed due to non-availability of anchor handling boat at the location. The Company also stated that all efforts would be made in future by providing proper anchor handling boat in time so that such waiting does not occur. The Company also pointed out that its Drilling Services group had already proposed (April 2011) to abandon the well temporarily and plan for re-entry after monsoon which was not done by Geology Operations group of its Western Offshore Basin.

MOPNG also stated (August 2015) that the decision was on time and there was proper coordination. However, the delay was due to non-availability of the anchor handling boat.

The Company in its supplementary reply (August 2015) post Exit Conference added that due to an unusual phenomenon of lack of small window of normal weather during the entire monsoon period, BOP could not be lowered.

The reply of the Company/ MOPNG needs to be viewed in the context of the following:

a) Lack of internal coordination in the Company is indicated. Though a decision had been taken to change the rig heading, it could not be implemented for want of anchor handling boat. The suggestion to abandon the well temporarily was also not implemented leading to idling of the rig and unfruitful expenditure of ₹ 90.57 crore.

b) In the joint review meeting (July 2011) held by the Director (T&FS) it was categorically stated that the rig waited for two months for favorable weather due to delayed decision leading to wastage of the precious rig inputs and disturbing the committed work programme. It was stressed at the review meeting that such critical decisions should be in time and based on experience.

D Idling of rigs waiting for logistics

Logistic Services group was responsible for ensuring timely availability of materials required by the offshore rigs for their drilling activities. The Service Level Agreement entered between the Logistic Services and the Assets and Basins, stipulated all time support by logistics services group to ensure material supply to various rigs deployed for drilling. However, the Company did not have adequate number of Offshore Supply Vessels (OSVs) to supply material to the rigs. The overall availability of OSVs varied between 80 and 88 *per cent* during the period of audit (2010-14). Non availability of OSVs to supply materials, tools, casings and services led to rigs idling on site waiting for logistics. Over the period

2010-14, the cost to the Company for idling of rigs for want of logistics was ₹ 185.84 crore. It was noticed that the Company had inordinately delayed (three years) the process of acquiring new OSVs and, till date (May 2015), only five out of the 12 contracted OSVs had been delivered (during March 2013 to September 2014) to the Company though all OSVs were due for delivery by December 2011 leading to shortage of OSVs and consequent idling of rigs for want of logistics.

A scrutiny of all the 79 wells drilled in the Western Offshore Basin (during 2010-14) revealed that rigs waited for casing pipes and tow boats for 688.25 hours costing the Company an avoidable expenditure of ₹ 13.77 crore. It was noticed that Director (T&FS) had observed (July 2011) that wells waiting for casing was unacceptable and proactive action needs to be taken to avoid wait for casings. It was intended (April 2013) to prepare a look ahead for 15 days and include the same in DPR for all offshore drilling (currently this was followed in deep water areas alone) to improve coordination amongst service providers and reduce avoidable down time. On scrutiny of the DPRs it was observed that this concept had not been introduced yet (March 2015).

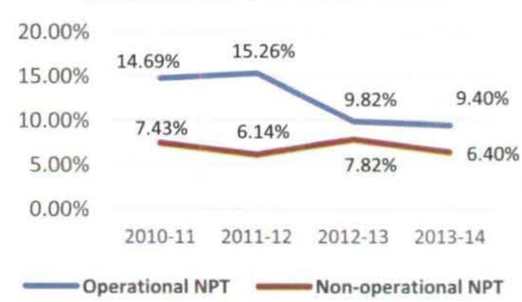
The Company replied (September 2014) that the stock position of the casings of the required dimension was adequate and the rig had to wait due to limited resources of OSVs, as the material could not be transported in time. The Company (May 2015) also assured that it was committed to reduce rig waiting for want of material and that an all-out effort was being made to improve coordination with Logistics Services group. The Company in its supplementary reply (August 2015) stated that Notification of Award (NOA) has been placed for 20 more vessels which are likely to join by September 2015 which would meet the requirements and two more supply bases are being set up nearer the fields. This would have a positive effect in reducing the NPT due to waiting for logistics and supplies.

Audit acknowledges the corrective action taken by the Management. The effectiveness of the corrective action in bringing down the NPT/ waiting time would be watched in future audit.

5.3.2 NPT of rigs deployed in onland areas

Over the period 2010-14, the total NPT of rigs deployed in onland areas ranged between 15.8 and 22.1 *per cent*. It was noticed that both operational and non-operational NPT was on the decline over this period, with operational NPT exhibiting a sharper fall. The unfruitful expenditure due to idling of rigs on account of controllable NPT (excluding rig break-down) was ₹ 888 crore during 2010-14.

Chart 5.5: NPT in onland areas



The Company stated (March 2015) that NPT was an operational issue and efforts were being made to minimize the loss. Efforts were being made by inducting new technologies, real time monitoring through SCADA[15] system and night supervision for deep exploratory wells, improving planning through 15 days look ahead *etc.* The Company, however, stressed that it

[15] ***SCADA – Supervisory control and data acquisition.***

would not be possible to completely eliminate NPT and that it was not prudent to consider it as extra expenditure as it was part of drilling operations.

The Company's contention that NPT was essentially on account of operational factors was not acceptable as onland rigs often idled in waiting for non-operational factors like land acquisition, civil work, environmental clearance, logistics support as well as associated services which could have been entirely eliminated with better planning and coordination as discussed under paragraph 5.3.2.1, 5.3.2.2. While the operational NPT had shown a steady decline, the non-operational NPT remains at a considerable 6.4 *per cent* of the available rig time and contributes to significant unfruitful expenditure.

Audit scrutinised deployment of 33 onland rigs (out of the 160 onland rigs deployed during 2010-14). Specific instances of idling of onland rigs noticed in the sample studied are indicated below:

5.3.2.1 Idling of onland drilling rigs due to non-availability of ready locations and logistics

In a significant number of the cases scrutinised (39 cases in which 18 rigs were deployed), Audit noticed that the rigs idled due to the following reasons:

- Non completion of civil works when the rigs were deployed. In majority of the cases, delay in civil works was on account of delay in tendering for it. In other cases, delay was on account of delay in land acquisition.
- Non availability of manpower and logistics (transport fleet, O&M crew).

In all these cases, the rigs were deployed without checking the readiness of the location for taking up drilling activities. The idling of these rigs cost the Company ₹ 132.25 crore.

Audit noticed that EC had decided (March 2011) that a drilling schedule to be prepared to avoid idling of rigs so that subsequent locations against a rig were readied in time for deployment of rig.

Table 5.4: Drilling schedule for Type I rigs

Present Well	Next Loc.1	Next Loc.2	Next Loc.3	Next Loc.4	Next Loc.5
Under Drilling	Should be ready	Civil Works in progress	Land Acquisition (LAQ) done	LAQ in progress	Released & Staked

Table 5.5: Drilling schedule for Type II & III rigs

Present Well	Next Loc.1	Next Loc.2	Next Loc.3	Next Loc.4
Under Drilling	To be ready before hermetical testing at previous well	Tendering for civil works in progress	LAQ in progress	Released & Staked

However, it was noticed that the directives of EC were not adhered to in all the cases reviewed by Audit. Ankleshwar Asset had to deploy rig M-450-1 to work-over operations for a period of 73 days as subsequent locations were not ready (civil works were not complete at the locations). In the process, the Asset incurred an additional expenditure of ₹ 4.05 crore (the additional cost of deploying drilling rig to work-over site).

The specific instances of idling of rig E-760-9 for 459 days over the period (2012-14) are detailed below as a case study:

A. Rig E-760-9 had been deployed to location AT-15 in Cachar Forward Base, Silchar, Assam in December 2011. The production testing of the well could not be completed for want of requisite resources for testing. The rig was, therefore, released (July 2012) to a new location ATDA keeping the well AT-15 incomplete even after an expenditure of ₹ 33.52 crore. At the new location, the rig was kept idle for 288 days as civil works at location remained incomplete. The decision to transfer the rig to the new location without ascertaining its readiness for drilling led to idling of the rig as well as the expenditure on the incomplete well remaining un-fruitful.

The Company/MOPNG replied (April/August 2015) that as no work centre was able to give any commitment and time line for the resources, it was decided to temporarily suspend the well. At the time of releasing the rig from well AT-15 on 31 July 2012, tender for civil works had not been finalised. As no other location except ATDA was available for taking up drilling operation, the rig was moved to the site. The Company also pointed out that civil works at ATDA was started in January, 2013. The delay in carrying out the works was due to land acquisition problem.

Reply of the Company/MOPNG needs to be viewed in the context of the following:

- The requisition for material was sent only in July 2012 after completing the testing for six objects. The rig was released hastily in July 2012 even though the Company was aware that the civil works at the new site had not yet commenced.
- The delay in civil works at new site was on account of deficient tender practices on the part of the Company. Besides, right of entry to the site was available with the Company from May 2012 but the Company initiated settlement for land acquisition only in November 2012.

B. The rig E 760-9 was deployed to well AT-16 in Cachar Forward Base, Silchar, Assam in April 2011. The well was spudded in May 2013 and production testing was in progress when the rig was called off to drill another well TKAC urgently. The rig was released in October 2013 (21 October 2013) with the production testing incomplete. The rig, however, could not commence operations at the new site (TKAC) as the site was not ready. The rig waited at site for 171 days and the drilling commenced only on 10 April 2014. Besides, the work at well AT-16 remained incomplete, thus, rendering the expenditure on the well of ₹ 24.15 crore unfruitful.

The Company/MOPNG replied (April/August 2015) that at the time of releasing the rig, civil works was under progress at TKAC and it was expected that the site would be ready for spudding before 4 December 2013. However, change of foundation from strip to pile, due to less bearing capacity of the soil, led to delay in civil works.

Reply of the Company/MOPNG needs to be viewed in the context that the rig was urgently called off in October 2013, though the site was expected to be ready only by December 2013. Besides, the delay in civil works was on account of delay of six months by the Company in publishing NIT which affected the readiness of site and led to idling of the rig.

Thus, in both cases, rig E 760-9 idled for considerable periods after being urgently shifted to new locations which were not ready for drilling. Not only did the rig remain idle, the work done on previous locations remained incomplete rendering the expenditure on these jobs unfruitful.

5.3.2.2 Onland rigs idled for want of environmental clearance

A. Tripura Asset: Rig E-1400-11 waited at location KHBK in Tripura for over six months (February 2014 to August 2014) as the environment clearance for drilling the site had not been received. The rig had been released for this location on 01 January 2014 and rig building prior to actual drilling was completed on 08 February2014. The drilling, however, could not commence in the absence of environmental clearance which was finally received on 05 August 2014.

Audit observed that location KHBK was at a distance of 1.5 km (approx.) from the boundary from Rowa Wildlife Sanctuary (RWS) and Tripura Government had specifically informed (April 2013) that "the process for delineation of Eco-Sensitive Zone was going on and until it was notified, the restriction of 10 km shall prevail and no clearance at the moment can be considered". The deployment of the rig to location KHBK in the context of the specific advisory of the Tripura Government, without environmental clearance was imprudent and led to avoidable idling of the rig for 187 days costing the Company ₹ 16.83 crore.

In reply, the Company/MOPNG stated (April/August 2015) that on completion of testing of well KHBL the rig E-1400-11 was released for KHBK on 01 January 2014 on approval from competent authority and in anticipation/assurance of EC consideration in the Expert Appraisal Committee scheduled on 30 January 2014. On recommendation by the State Government to National Board Wildlife, the consent for operation of the rig at location KHBK was received on 13 July 2014.

The reply of the Company/MOPNG highlights the idling of the rig being deployed in anticipation of environmental clearance which was received six months later. The idling resulted in unfruitful expenditure of ₹ 16.83 crore.

B. Cauvery Asset: The location MTAM of PEL Block L-II of Cauvery Basin was released on 14 November 2009. Over a year later, the Company applied (20 December 2010) for environmental clearance for the block including this location. Meanwhile, civil works were taken up on the location and completed by February 2012. The rig E-760-16 was deployed on the location in August 2012 for 23 days (27August 2012 to 18 September 2012). However, as environment clearance for the site was not available, drilling could not commence. Subsequently, the rig was diverted to another location.

The environment clearance for the location was received on 21 August 2013. The well was again taken up for drilling and the work was completed in September 2013 (19 September 2013).

Audit observed that at the time of initial rig deployment in August 2012, the Company had neither submitted its final report for environment clearance nor had public hearing and consultation process been completed (this was subsequently done during December 2012 to March 2013). Thus, even while deploying the rig in August 2012, the Company was aware of the status of the location and inability to drill the site. This led to idling of the rig for 23 days (idling cost to the Company ₹ 1.41 crore).

The Company/MOPNG replied (November 2014/August 2015) that in anticipation of getting the environmental clearance in time, rig E-760-16 was released to location MTAM on 26 August 2012, mobilisation and rig building operations were carried out till 17 September 2012. Despite best efforts, as EC for MTAM could not be obtained, to avoid rig-idling, rig E-760-16 was released from MTAM on 18 September 2012.

The reply of the Company/MOPNG was not acceptable since the rig was released in the first place without obtaining environmental clearance. The decision to deploy the rig in anticipation of environmental clearance was imprudent and led to idling of the rig.

5.3.3 Idling of work-over rigs in onland areas

As on March 2014, the Company had 56 departmental and 23 hired work-over rigs for deployment in onland areas. The deployment of work-over rigs in two Assets, Assam and Tripura was scrutinised in Audit.

A. **Assam Asset:** During 2010-14, 13 Departmental work-over rigs were deployed in the Assam Asset. Audit observed that the Departmental rigs remained idle for a considerable period of 580.80 rig days. It was seen that the rigs remained idle waiting for civil works, logistics, manpower, material *etc.* and the Company incurred extra expenditure of ₹ 19.96 crore on this account.

   The Company, while accepting the audit observation, stated (March 2015) that necessary steps were being taken to minimise the idling of work-over rigs during the operation period. MOPNG reiterated (August 2015) the Company's reply and further added that shortfall in manpower required for operations, if any, is being addressed appropriately. The corrective action of the Company in minimising the idling of work-over rigs would be watched in future audit.

B. **Tripura Asset:** The deployment of work-over rigs in Tripura Asset was scrutinised through a specific case study as indicated below:

   The Asset had hired a 100 Ton capacity work-over rig (John-100-25) in August 2010 for a period of three years. A review of deployment of the rig over the period 14 March 2011 to 31 May 2013 indicated that the rig had remained idle for 377 days (46.54 *per cent* of the available time of 810 days) and the contractor was paid ₹ 6.12 crore at non-operating day rates for this period. A scrutiny of the reasons for the idling indicated that the reasons were controllable by the Company:

   - The rig had to wait for civil works, logistics, manpower and material for 111 days costing the Company ₹ 1.80 crore. These were the responsibility of the Tripura Asset as per the terms of the hiring contract.

- The rig waited for 216 days for activation and observation of the wells which cost the Company ₹ 3.51 crore. Audit noticed that the wait was due to non-availability of adequate compressors with the Tripura Asset. The Asset had only two compressors and a proposal for installation of well stimulation services had been initiated in 2009 to address the problem. However, this proposal had not fructified and the Asset continued to work with two compressors which contributed to delay in activation of the wells.
- The rig also waited for testing, mud/brine preparation, tank cleaning *etc.* For 50 days costing ₹ 0.80 crore.

The Company assured (April 2015) the Audit that efforts would be made to minimize waiting of rigs for want of manpower, programme and materials and the activities like wire line jobs, logging, mud-brine preparation, waiting on cement *etc.* that were essential for completion of work-over jobs and were part of the planned work-over operational activities during which rigs have to remain in non-working state. Considering this, a provision had been incorporated in all contracts for payment to contractor for such situations at non-operating rates which was lower than the normal operating day rates. The Company also stated that work for setting up Well Stimulating Services base at Tripura Asset had been taken up and was in full swing. With this infrastructure it was expected that future activation jobs would consume less time besides monetizing production in shortest possible time. MOPNG reiterated (August 2015) the Company's reply and further added that shortfall in manpower required for operations, if any, is being addressed appropriately.

The corrective action of the Company in minimising the idling of work-over rigs would be watched in future audit.

5.4 Inefficiencies in operation of rigs

Besides idling of rigs, inefficiencies in rig operation had been noticed in both offshore and onland areas. In the sample studied in Audit, the following cases have come to light which are detailed below:

5.4.1 Offshore areas

A. Unfruitful expenditure of ₹ 1,577.27 crore due to unsafe operations

Departmental deep water drilling rig, Sagar Vijay, was deployed for drilling exploratory location G-4-6 (AF) on 31 March 2008. Production testing on the well commenced on 28 February 2009. During production testing, on 16 April 2009, wire rope of anchor #7 parted. Though this was a safety concern, Drilling Services group of the Company continued production testing and perforated[16] the well on 19 April 2009.

Efforts to retrieve and re-lay the anchor commenced on 19 April 2009 without sufficient crew and was not successful. However, the incident was not reported in the Daily Drilling Report

[16] ***Perforation is a process used to establish a flow path between the near reservoir and the wellbore. It normally involves initiating a hole from the wellbore through the casing and any cement sheath into the producing zone.***

till 20 April 2009. On 22 April 2009, another anchor #8 also parted. Without two anchors (#7 and #8), the rig moved 140 metres from the location. The well had to be immediately closed and the anchors #7 and #8 were re-laid. At this stage, Blow Out Preventer (BOP), an essential safety equipment, had tilted and its retrieval was difficult. The rig was dry-docked on 18 May 2009 without recovering the BOP. By then, the Company had incurred an expenditure of ₹ 347.03 crore on drilling location G-4-6 (AF).

Subsequently, a relief well had to be drilled by deploying rig M.G. Hulme in order to make the well safe and retrieve the BOP. The relief well took 411 days (October 2011 to November 2012) and an expenditure of ₹ 1,033.44 crore was incurred. In the meanwhile (2012-13), rig Sagar Vijay drilled three wells without BOP. As it was unsafe to operate without BOP, rig Sagar Vijay drilled these three wells only partially with the upper completion being done during December 2012 to August 2013 by another CH rig, 'Actinia' by incurring an extra cost ₹ 196.80 crore to the Company in comparison to the cost of operation of Sagar Vijay.

Audit noticed that the Company reported (May 2009) the incident to M/s United India Insurance Company Limited (UIIC) and lodged a claim of US$ 22 million (₹ 132 crore approx). The reinsurers denied (December 2012) the claim stating that the Company's decision to continue with operations and perforation of the well after the first anchor (#7) parted was not a recognized safe operating practice. The reinsurers also pointed out that the Company had failed to comply with the duty imposed by the insurance policy to exercise due care and diligence and, hence, were not eligible for compensation. Later (February 2013), in finalising the settlement of another insurance claim, the Company also confirmed to the reinsurer that no litigation would be brought in respect of its claim regarding Sagar Vijay. Thus, the Company also agreed not to pursue its insurance claim further on the rig Sagar Vijay.

Audit noticed that the report submitted (July 2013) by an independent agency M/s Novodrill appointed by the Company on this incident, had also concluded that responsibility for the incident lay with the Company. The report pointed out that anchor #7 had not been repaired before the well was perforated and that the well was live when anchor #8 parted while stressing that this was a major aberration and the Company ought not to have allowed this to happen.

The Company stated (April 2015) the following:

(i) After parting of anchor #7, there was no significant change in vessel position, in riser angle. The weather parameters were within operational limits and there was no adverse weather forecast for next one week. Anchor tensions were continuously monitored and the remaining seven anchors had tensions well within permissible limits. Historically on few occasions, operations had been continued on seven anchors.

(ii) During the time of parting of anchor #7, the perforating charges were already in the well as running of completion (production) string was done. Based on above points, it was opined to continue operations on the well G-4-6. This indicated that due care and diligence was exercised prior to taking the decision to continue operations.

(iii) The rig Sagar Vijay was deployed to carry out Top Hole drilling of three wells to utilise its services despite non-availability of its BOP stack. These wells were subsequently completed using the charter hire rig Actinia and, thus, the expenditure incurred for these operations cannot be termed unfruitful, as the Company had carried out job as per availability of resources/ constraints.

MOPNG/ the Company in its supplementary reply (August 2015) reiterated the contention that the Company had not adopted any unsafe operation and the report of the internal committee was only a suggestion for improvement.

Reply of MOPNG/the Company needs to be viewed in the context of the following:

(i) The proximate cause for parting of wire ropes (#7 and #8) was due to poor maintenance procedures of the Company and inherent deterioration in the mooring wires as concluded in report of the independent agency, M/s Clyde and Company, appointed by the reinsurers.

(ii) The anchor #7 parted on 16 April 2009 and even after six days i.e. 22 April 2009, it was not re-laid. In the Company's internal enquiry report, it was emphasized (October 2009) that in case of any anchor failure, the operation should be suspended and re-commenced only after all anchors were in place.

(iii) Subsequent to the incident, an advisory note was issued to Group General Manager (Head Drilling Services) against allowing continuance of critical operations with a broken anchor. Thus, contention of the Company that due diligence had been done in this case was not justified. Compromising the safety of operations by citing historical occasions of operating the rig with seven anchors was not prudent/ safe practice and established the fact that the Company had carried out operations against established and safe procedures.

(iv) Both the independent agencies appointed by the Company and the reinsurers opined that the decision to continue with the planned well perforation, despite failure of one anchor was not a recognised safe operating practice and ought not to have been done.

The Company, thus, incurred an avoidable expenditure of ₹ 1,577.27 crore (₹ 347.03 crore on drilling the abandoned well plus ₹ 1,033.44 crore on relief well and BOP retrieval plus ₹ 196.80 crore on deployment of another rig for completing the wells drilled by Sagar Vijay) in continuing production testing operations without rectifying the anchor problem which was a serious safety lapse and led to loss of a hydrocarbon bearing well.

B. Operating owned offshore rigs without consent for operation

As per provision 17 of Petroleum and Natural Gas (Safety in Offshore Operations) Rules 2008, an operator of a mobile installation operating in Indian waters before the commencement of these Rules, had to submit an application for consent of operations within a year of commencement of the Rules. The operator failing to submit such application within a period of six months would be liable to penalties under the Oil Industry (Regulation and Development) Act, 1948.

The Company had eight offshore rigs, of which four (50 *per cent* of the fleet) did not have consent for operations. In case of these four rigs, the requirement for obtaining consent for operations was yet (May 2015) to be fulfilled.

The Company stated (April 2015) that in case of the four owned rigs, the 'fit for purpose certificate' alone had not been obtained. Other Rules had been adhered to. The Company also informed that efforts for obtaining 'fit for purpose certificate' for the four jack up rigs *viz.* Sagar Gaurav, Sagar Jyoti, Sagar Kiran and Sagar Shakti were being made and the matter was in an advanced stage. MOPNG endorsed (August 2015) the Management's reply on the expectation of obtaining 'fit for purpose certificate' by December 2015.

It is pertinent to note that all the offshore rigs hired by the Company had obtained consent for operation in offshore areas while the Company, being a major National Oil Company, could not complete the process even after seven years of notification of the Rules.

5.4.2 Onland areas

5.4.2.1 Delay in termination of contract

The Company contracted (October 2008) rig Shiv-50 from M/s. Shiv Vani Oil & Gas Exploration Services Limited, New Delhi (contractor) for a period of three years. The rig was deployed in Assam Asset on 30 April 2010 and was continued beyond the contractual period of three years ended *i.e.* 29 April 2013 on the same terms and conditions for completing the last well.

Audit noticed that the rig had problems in operation. The problems started in March 2013, when the well had been drilled upto a depth of 2602 metres against target of 4,964 metres and crew struck work for ten days, before scheduled expiry of the contractual period. It was decided to continue the contract for completion of the well. Subsequently, a continuous set of problems were encountered - crew strike (May to August 2013), non-availability of high speed diesel (May 2013), non-availability of equipment (May 2013), rig break down (June 2013). Besides, mud services were withdrawn from May 2013. As of April 2015, the well had been drilled only upto a depth of 4,817 metres.

The Company issued the first notice to the contractor citing unsatisfactory performance in August 2013, three months after the Asset had requested ONSG, Vadodara for issue of such notice. In this notice, the Company allowed the contractor 15 days to correct the specified deficiencies and improve performance. Though the contractor did not take requisite measures and the operation remained disturbed, the Company took another two months to issue (October 2013) 30 days' notice to the contractor for termination of contract. The Company finally issued the termination notice on 21 April 2014. The tardy action on the part of the Company in initiating appropriate action against a defaulting contractor led to continuation of the contract arrangement with intermittent interruptions up to November 2013, by which time the contractor had drilled the well upto 4,817 metres. The contractor stopped work thereafter.

Meanwhile, the well remained incomplete even after incurring an expenditure of ₹ 39.51 crore. It was also noticed that the contractor did not remove the rig from the site, though the Company requested for the same in April 2014. Subsequently, the Company served a legal notice (September 2014) on the contractor for vacating the drill site. The rig was yet (April 2015) to be moved from the site by the contractor.

Failure of the Company to initiate timely action against the contractor led to non-achievement of drilling objective for the well and blockage of ₹ 39.51 crore. Though the Company had not paid the contractor for the period the rig remained idle, no other penalty had been levied in the absence of enabling provisions in the contract.

In reply, the Company stated (March 2015) that from 06 March 2013 to 01 August 2013, several letters/ performance notice were served to the contractor whenever poor performance was noticed. The case for termination of contract was processed by ONSG, Vadodara and termination order was issued after taking approval of EPC. The completion of the well was planned after removal of Rig Shiv-50. However, M/s Shiv Vani had not vacated the site till now (April 2015). MOPNG reiterated (August 2015) the Company's reply. The Company in its supplementary reply (August 2015) added that a show cause notice has been issued to M/s. Shiva Vani in this regard by Estate Officer under section 4 of Public Premises Act, 1971.

Reply of the Company was not acceptable as there was delay on the part of the Company in terminating the contract. Though the mud services, which was a vital service for drilling the well, was withdrawn from the rig on 20 May 2013, the Company terminated the contract nearly a year later in April 2014.

5.4.2.2 Diversion of Drilling Rigs for production testing

Mehsana Asset hired (June 2010) a 100 ton capacity work-over rig exclusively for production testing of exploratory wells. The rig was, however, not utilised for production testing but for other work-over jobs. Meanwhile, the Asset deployed costlier drilling rigs for production testing. This resulted in avoidable additional expenditure of ₹ 24.57 crore.

In reply, the Company stated (March/ August 2015) that while the costlier rig was used for work-over operations, work-over (lighter) rigs from the Asset were deployed to take up testing operations as per need.

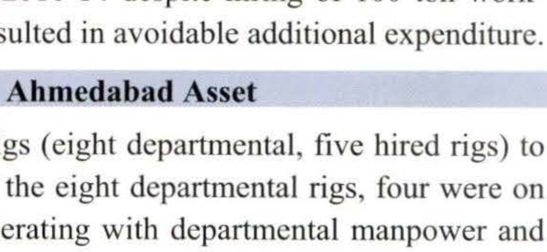
The reply of the Company may be viewed in the context of utilisation of costlier rigs in production testing of 35 exploratory wells during 2010-14 despite hiring of 100 ton work-over rig exclusively for production testing which resulted in avoidable additional expenditure.

5.4.2.3 Shifts not planned for work-over rigs in Ahmedabad Asset

The Company during 2009-14 had 13 work-over rigs (eight departmental, five hired rigs) to meet the work-over need of Ahmedabad Asset. Of the eight departmental rigs, four were on operation and maintenance contract, three were operating with departmental manpower and one rig by rotation remained at Central Workshop, Vadodara for overhauling.

Audit noticed that 81 *per cent* of un-available hours during 2009-14 was because shifts for these rigs had not been planned by the Asset. Nearly the entire period of shifts that were not planned comprised of departmental rigs (97 *per cent* of the entire period, accounting for 18,200 hours). At the same time, the inventory of sick wells increased as seen in the chart alongside.

Chart 5.6:
Inventory of sick wells at the end of the year.



Thus, the departmental work-over rigs remained idle, shifts for deployment of these rigs not having been planned, even as the necessity of work-over jobs increased as seen from the increasing number of sick wells.

The Company stated (April 2015) that due to unavoidable circumstances like delay in replacement of operation and maintenance services, such delays had occurred and that all efforts were being made to avoid/ minimise such delays in future by taking suitable actions. MOPNG in its reply stated (August 2015) that necessary steps are being taken to ensure timely availability of manpower through recruitment/ hiring to avoid situations like shift not planned. The tender of hiring O&M services is now being invited sector-wise so that alternate arrangements can be made from other work centres in the sector (in the event of lack of adequate response to tender).

The assurance of the Company would be watched in future audit.

5.5 Drilling Efficiency

A. Cycle Speed

Efficiency of rigs is determined through the cycle speed and commercial speed of the rigs. The total time taken by a rig in a complete cycle[17] is called as cycle time in months or rig months. The cycle speed defines the efficiency of operations during the entire cycle of a deployed rig and was calculated as meterage drilled during the rig month deployed.

Performance of drilling operations in terms of cycle speed of rigs deployed by the Company during the four years from 2010-11 to 2013-14 is tabulated below:

Table 5.6: Performance of drilling operations in terms of cycle speed (metres/rig month)

Area		2010-11			2011-12			2012-13			2013-14		
		Plan	Actual	%	Plan	Actual	%	Plan	Actual	%	Plan	Actual	%
Offshore	Basins	909	737	81%	988	886	90%	976	873	69%	955	665	70%
	Assets	1,408	1,280	91%	1,500	1,331	89%	1,482	1,419	96%	1,486	1,157	78%
	Total	1,037	869	84%	1,213	1,048	86%	1,194	1,127	94%	1,194	869	73%
Onshore	Basins	589	521	88%	622	563	91%	599	566	94%	628	559	89%
	Assets	833	964	116%	907	961	106%	831	986	119%	852	983	115%
	Total	696	736	106%	746	768	103%	723	809	112%	747	800	107%

Source: Director (T&FS) Annual Report 2010-11 to 2013-14

From the above table it was evident that in offshore, the Company could not achieve the planned cycle speed for all the years both in Basins and Assets. The main reason for non-achievement of planned cycle speed was poor performance of owned rigs compared to CH rigs. In onland area, the Company could not achieve the planned cycle speed in Basins, though the performance in Assets exceeded the plan. Audit observed that in four onland Assets (three Assets of Western Onshore and Tripura Asset) where the Company had shown better performance than planned, the cycle speed target was kept lower though Assets consistently performed better during the previous years.

[17] ***Comprises rig building, drilling and production testing and rig move.***

Analysis of the cycle speed achieved by offshore rigs (both owned and CH) during 2010-14, revealed very poor performance of owned rigs. Though the cycle speed of own offshore rigs had improved over the last four years, it could at best reach 50 *per cent* of the cycle speed of CH rigs.

Audit noticed that the variation in performance of owned and chartered rigs was attributed to large scale attrition of experienced manpower, higher age bracket of the Company crew (45-47 years) and ageing of rigs and equipment. The Executive Committee (EC) of the Company decided (March 2011) that a work centre-wise benchmarking should be carried out which would include comparison among Assets as well as comparison vis-à-vis other oil companies. Institute of Drilling Technology (IDT) - an organisation within the Company, was to set (March 2011) these benchmarks. It was noticed that IDT was yet (May 2015) to benchmark drilling activities for offshore Assets and Basins. In case of onland activities, benchmarks had been set (July 2011) for onland Assets alone (the exercise for Eastern region yet to be completed till May 2015) and benchmarks for onland Basins were yet (May 2015) to be drawn up. Audit noticed that the limited benchmarking done, did not indicate comparisons of time norms with other peer companies.

Audit also observed that the Company did not maintain its own jack-up rigs properly mainly due to absence of specific policies on major lay-up repairs of these rigs and equipment replacement of offshore rigs, which were formulated very late in 2007 and 2008 respectively *i.e.* after lapse of 25-26 years of commissioning of owned rigs. In its absence, the owned rigs were continuously operated with obsolete equipment/ outdated system affecting the rig efficiency.

The Company in reply stated (April 2015) the following:

(i) The cycle speed considered in FYP / annual plan/ RDP was based on limited data and past experience of the field. Actual drilling days were likely to vary which cannot be accounted for in advance planning. Production testing and activation duration of a well could also vary depending on level of formation pressure depletion. Increasing depletion of producing zones and drilling in lesser known marginal fields had also affected cycle speed. Hence, cycle speed could not be solely treated as an absolute performance indicator.

(ii) The Company was in the process of hiring an international consulting agency to strengthen its benchmark norms while maintaining that the benchmark norms were field specific and resource based and it would not be practical to make comparison with rigs operating in different environment as it would not be "Like to Like" evaluation. The Company also added that recommendations of Original Equipment Manufacturer (OEM) of individual equipment/system on board the jack up rigs and Classification Agency surveyors in periodical surveys were implemented to (a) ensure safety and (b) meet class rule requirements. The efficiency of drilling services group had been affected due to lack of an apt manpower on the rigs. The ongoing recruitment exercise to fill-in the approved posts in drilling discipline at staff level was expected to add 538 employees to the above availability tally of 1131, which would lead to adequate overall manning.

The Company in its supplementary reply (August 2015) added that the Company's rigs being old and not upgraded, all the new technology used in charter hired rigs cannot be used in most of the Company's rigs. Aggressive recruitments have been initiated since 2008-2010. This being a highly skilled functional area the new inductees have been exposed to field operation one year after induction. During the first year they are provided a structured classroom/ field training. A period of 5-7 years is a reasonable time to develop these skills.

Reply of the Company needs to be viewed in the context that:

(i) The Company fixed target for cycle speed both for owned and charter hired (CH) offshore rigs based on past performance of rigs *i.e.* average time taken for different category of wells. Efficiency of owned rigs during the period reviewed by audit was in the range of 27 to 49 *per cent* of that of CH rigs. Even with adoption of efficiency enhancing measures, such as advance mud systems, new generation bits and new technologies, the cycle speed of offshore rigs did not improve noticeably. The Board of Directors of the Company also observed (October 2014) that there were opportunities to improve the drilling efficiency of CH rigs as well.

(ii) The comparison among peers as envisaged by EC would lead to better analysis of weaknesses which had not been taken up.

(iii) The Company also did not recruit drilling manpower commensurate with the retirement/transfer/attrition. While the Company's action to recruit more employees in drilling discipline was appreciated, pending induction of Q1/Q2 executives and staff (pending induction of 2013-14 and 2014-15 executives and staff), the shortages were met by Q3 executives mostly with age >50 years. Considering the age and qualification profile of such executives, the desired output could not be achieved which affected the drilling efficiency. Even after considering the completion of the recruitment process, lack of skilled manpower would continue to hinder the operational efficiency of rigs in the years to come.

B. Commercial speed

The commercial speed is a measure of meterage drilled against time taken from spudding the well to the hermetical testing[18]. It is expressed as metre / rig month. In case of onland rigs, Ahmedabad and Agartala Assets alone had planned the commercial speed and the remaining nine Assets did not plan for commercial speed. However, the commercial speed of offshore rigs was not planned. The commercial speed achieved both in offshore and onland rigs during 2010-14 is tabulated below:

Table 5.7: Achievement of commercial speed in offshore and onland areas (metres/rig month)

Area		2010-11	2011-12	2012-13	2013-14
Offshore	Basins	1,109	1,134	1,154	978
	Assets	1,784	1,696	1,861	1,604
	Total	**1,282**	**1,340**	**1,484**	**1,246**
Onland	Basins	756	814	885	908
	Assets	1,427	1,401	1,466	1,459
	Total	**1,079**	**1,116**	**1,228**	**1,233**

Source: Director (T&FS) Annual report 2010-11 to 2013-14

[18] ***Hermetical testing refers to the closed cycle pressure testing of casings of wells completed by pumping water at steady rate to detect leakage before handing over the well for production testing.***

Commercial speed in offshore area during 2013-14, both in Basins and Assets, showed a declining trend compared to previous years. As regards onshore rigs, the overall achievement of commercial speed was on increasing trend during 2010-14 both in Basins and Assets.

The Company/MOPNG stated (April 2015/August 2015) that the actual drilling time varied depending on factors like presence of loss zones, high pressure zones, problematic formations, limitations on well profile due to nearby wells and its effect on actual depth of well *etc.* Hence, actual drilling days were likely to vary accordingly which could not be accounted for in advance planning. Also that the cycle speed and commercial speed could not be a sole and an absolute performance indicator.

Reply of the Company needs to be viewed in the context that the performance had deteriorated in Offshore Assets and Basins due to non-maintenance of owned rigs, delay in dry docking/major lay-up repairs (commented in the paragraphs 6.1.1 and 6.1.3) and non-improvement in efficiency in spite of deployment of new generation rigs and introduction of new technologies. In the performance contracts entered into between Performance Management and Benchmarking Group and the Drilling Services groups of the Company, the Company itself had adopted the cycle speed and commercial speed as the key performance indicators for measuring operational and drilling efficiency and extent of utilisation of the rigs. Hence, reply of the Company that these parameters cannot be solely treated as an absolute performance indicator was not justified.

C. Deficiencies in Target setting of commercial and cycle speed in Performance contracts

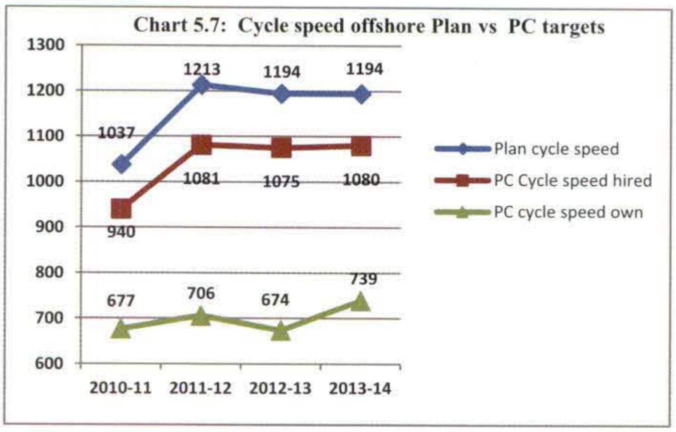
The Performance and Bench Marking Section of the Company enters into Performance Contracts with Assets, Basins and Services setting targets on Key Performance Indicators (KPIs) based on the MOU targets entered into with MOPNG. The KPIs to measure operational and drilling efficiency of Drilling Services group were in terms of cycle speed and Commercial speed. A single cycle speed and commercial speed (applicable for both offshore and onland drilling) was set as the KPI target. The planned cycle/ commercial speed (as per KPI) and the actual cycle speed for onland and offshore areas, segregated by owned and CH rigs, is depicted in the table given below:

Table 5.8: Statement showing target and actual achievement of cycle speed and commercial speed **(Meters/Rig Months)**

KPIs	Types of rigs	2010-11		2011-12		2012-13		2013-14	
		Target	Actual	Target	Actual	Target	Actual	Target	Actual
Cycle speed	Onland Owned	677	803	706	781	674	833	739	802
	Onland CH	940	733	1081	757	1075	819	1,080	805
	Offshore Owned	677	353	706	303	674	490	739	484
	Offshore CH	940	1,057	1,081	1,105	1,075	1,167	1,080	993
Commercial speed	Onland Owned	1,096	1,194	1,055	1,153	1,108	1,286	1,249	1,247
	Onland CH	1,331	1,045	1,239	1,064	1,210	1,200	1,425	1,018
	Offshore Owned	1,096	738	1,055	5,78	1,108	736	1,249	756
	Offshore CH	1,331	1,544	1,239	1,355	1,210	1,503	1,425	1,388

In this regard, Audit observed the following:

- The cycle speed planned in the Annual Plans and agreed in the performance contracts with the Drilling Services group were different as shown in the chart alongside. The cycle speed planned by the Company in its Annual Plans were consistently higher than the KPI target fixed for the performance of Drilling Services group. Thus, while the Drilling Services group over-achieved their performance target as per Performance Contracts (PCs), the planned cycle speed could not be achieved by the Company (particularly for offshore drilling by owned rigs) as per Annual Plans.



- Poor performance of owned offshore rigs had been deliberated time and again in various forums. However, the same was not reflected in the performance of Drilling Services group which had consistently reported 'outstanding' performance for the four years under review. The performance contract was a basis for assessing the actual performance and payment of performance related pay. Hence, there was a necessity to properly set the target in the PCs both for own and CH rigs separately for offshore and onland to have desired stretch in the performance.

- A single 'target cycle speed' for owned rigs in the performance contract with Drilling Services group was also not conducive to efficiency. The target cycle speed for 2010-11 for owned rigs was 677 against which the Drilling Services group reported a performance of 723. However, the actual performance of offshore departmental rigs was 353 (~half the targeted efficiency). The higher performance of the onland departmental rigs at 803, and their higher weightage on account of their larger number (68 onland rigs as against nine offshore rigs) had shadowed the poor performance of offshore rigs. To monitor the performance of drilling realistically, separate targets would be essential for all four categories – offshore hired, offshore owned, onland hired and onland owned. In the absence of such area specific targets, it was not possible to assess the efficiency of Drilling Services group in operating the rigs.

- The Company had kept the cycle and commercial speed of its own rig around 30 *per cent* lower than CH rigs and had this in-built inefficiency in the targets itself.

During Exit Conference held with the Company in May 2015, the Director Offshore stated that fixing separate targets for owned rigs both offshore and onshore as well as hired rigs would be looked into and incorporated in the Performance Contracts of Drilling Services group in future. The Company in its supplementary reply (August 2015) stated that as suggested by audit separate KPI of cycle speed and commercial speed for Onshore (Owned and Charter hired rigs), Offshore - Shallow Water (Owned and Charter Hired rigs) and Offshore - Deep Water (Owned and Chartered Hired rigs) was created in Performance

Contract. This target is based on 10 *per cent* increment in previous year's performance till the new benchmark norms is in place.

Audit acknowledges the corrective action by the Company.

D. Drilling Cost

The cost of drilling per metre by owned and hired wells over the period 2010-14* is tabulated below:

Table 5.9: Cost of drilling wells by own and hired rigs

(In ₹)

Area	Type of rigs	2010-11	2011-12	2012-13	2013-14**
Exploratory	**Onland**				
	Departmental	86,097	82,059	1,12,906	1,14,282
	Contractual	1,18,675	1,05,239	1,02,118	1,03,822
	Shallow Water				
	Departmental	7,07,623	7,88,719	8,80,632	7,70,855
	Contractual	3,57,610	3,41,439	6,07,349	5,74,685
Development	**Onland**				
	Departmental	44,880	48,134	54,516	60,365
	Contractual	48,983	51,842	59,608	49,088
	Shallow Water				
	Departmental	0	0	0	4,74,217
	Contractual	2,19,729	2,24,271	2,03,257	2,17,539

**** Excluding NELPs, JVs and LDST-Long Drift Side Track wells.***
***** Excluding LDST wells in shallow water.***

Owned rigs were not deployed to development works during 2010-13 and, hence, no development drilling cost for owned rigs during that period was available, as shown in the table.

Departmental rigs were financially efficient in onland areas with the cost per metre drilled being lower for departmental rigs vis-à-vis hired rigs. However, the drilling cost of onland departmental rigs was on the rise and in 2013-14, it significantly exceeded the drilling cost of hired rigs for both exploratory and development drilling.

The drilling cost for offshore departmental rigs was very high compared to that for CH rigs. Over the period 2010-14, the cost of owned rigs for shallow water exploratory drilling was higher by 34 to 131 *per cent* than that of CH rigs.

The performance contracts of Drilling Services group had a KPI on drilling cost per metre both for exploratory and development wells. This KPI was not kept separately for the departmental and contractual rigs to compare and monitor the financial performance.

5.6 Skewed manpower in drilling activities

Adequate skilled manpower was essential for implementing the latest, state of the art drilling technologies. The operational efficiency of rigs was largely dependent upon proper manning of drilling rigs. The critical categories for operation of the rigs were the executives in the Q1/Q2 grades (the rig man, top man, *etc.*). Absence of adequate number of these resources affected drilling operations and was a major reason for higher repairs and loss of rig time. As on March 2014, there were 1,456 Q1/Q2 executives as against a requirement of 1,847 (21 *per cent* shortage). In contrast, the Q3 category was over-staffed. As against a requirement of 510, the available manpower was 1,490 (nearly three times the requirement). The skewed manpower availability led to poor operational performance in manning departmental rigs.

In particular, shortage of adequate staff was noticed in operation of two owned floater rigs, Sagar Vijay and Sagar Bhushan. In the absence of adequate manpower, the Company had decided to hire O&M services for efficient manning of these rigs. Tender for hiring O&M services was issued as early as 2007. However, it could not be finalised owing to agitations from staff. Subsequently, four years after cancellation of the earlier tender in 2008, the Company again decided to hire O&M services in September 2012. Delays in processing this tender had been noticed at various stages. The tender was yet (April 2015) to be finalised. Inordinate delay in hiring O&M services affected the drilling operations of both the rigs.

While accepting the audit comment, the Company stated (April 2015) that its crew was continuing drilling operations on both the drillships. Audit, however, noticed that as of April 2015 the rigs were managed with bare minimum crew, affecting rig performance.

MOPNG stated (August 2015) that the O&M contract for rig Sagar Vijay is still under process and the shortage of manpower in floaters is being managed through transferring executives from other region of ONGC. Due to the presence of experienced Q3 executives, the shifts on the rigs are managed with less number of Q1/Q2 executives. Immediate shortages of manpower are bridged by allowing outsourcing in select areas.

The reply needs to be viewed in the context of acknowledgement by the Management in various forums, that the ageing manpower in Q3 level and the unskilled manpower of new recruits are impacting the efficiency of own rigs/ floaters. More importantly, as admitted by the Management, a period of 5-7 years is required to develop the skills required for drilling operations. Thus, the delay in filling the manpower shortages during past years would have a cascading effect on the availability of skilled manpower in the years to come.

Chapter 6: Maintenance of Owned Rigs

The Company owned 67 onland and eight offshore rigs as on March 2014. For efficient functioning of the rigs, regular repair and maintenance was essential. Timely repairs and refurbishment was particularly important for offshore rigs which operate in marine environment. Delay in proper upkeep of a rig directly impacts its drilling efficiency and consequently the cost of drilling operations.

In the Company, the repair and maintenance of onland rigs were carried out in-house, through the Central Workshop, Vadodara. Refurbishment and up-gradation of onland rigs had been carried out through Bharat Heavy Electricals Limited (BHEL). The repair and refurbishment of offshore rigs and rig equipment was carried out through competitive tendering process after evaluating the effectiveness of such repairs.

6.1 Dry dock/major lay-up repairs of Departmental offshore jack up rigs

6.1.1 Delay in repairs of jack up rigs

Of the eight departmental offshore rigs, six were jack-up rigs and two were drillships. As per the class requirements, a drillship undergoes dry dock survey twice in a period of five years. However, in the absence of mandatory dry dock requirements for jack-up rigs, repair work of such rigs and rig equipment were carried out on a need basis rather than in a planned manner. The need for a dry dock policy in case of owned jack-up rigs had been highlighted in C&AG's Report No. 9 of 2007 (Paragraph 7.7.4.1, Chapter VII; 'Performance of offshore rigs in shallow water areas of ONGC'). Subsequently, the Company formulated (2007), a policy for dry dock management and major lay-up repairs of jack-up rigs. As per this policy, dry dock of jack-up rigs was to be carried out every six to eight years, depending upon physical inspection and verification by the competent authority.

The six jack-up rigs had been purchased between 1982 and 1990. Considering the practical aspects of drilling operations and shipyard considerations, the Company drew up a five year dry dock road-map for these rigs in May 2007. Meanwhile, Sagar Kiran was sent for dry dock during 2005-08. As per this plan, dry dock and major lay-up repairs of four rigs were planned in 2007 (Sagar Kiran, Sagar Ratna, Sagar Uday, Sagar Gaurav); and the balance two were planned for 2008 and 2009 (Sagar Shakti for 2008 and Sagar Jyoti for 2009). Thus, major lay-up repairs for all the rigs were to be completed by 2009.

Audit observed that, major lay-up repairs of only two rigs, Sagar Ratna and Sagar Uday had been carried out (in 2012 and 2013 respectively). The tender for repair of Sagar Jyoti was under process. Review of drilling workload for the years 2014-18 prepared (November 2014) by the Company revealed that major lay-up repair was not planned for rigs Sagar Shakti and Sagar Gaurav.

The Company stated (April 2015) that due to continuous work requirement, the rigs could not be taken out of cycle for major lay-up repairs as scheduled, though all preventive maintenance practices were followed as per the OEM recommendations and periodical classification surveys were complied with.

The reply needs to be viewed in the context of repair policy itself being delayed by over 25 years and being laid down to streamline management of dry dock of jack-up rigs. Non adherence to the repair schedule led to rigs being operated with outdated/ obsolete equipment which adversely impacted operational efficiency of the rigs as shown in the table below:

Table 6.1: Efficiency in terms of cycle speed of owned jack-up rigs

Name	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Owned Rigs										
Sagar Jyoti	262	88	426	428	601	426	223	563	447	295
Sagar Gaurav	544	418	426	Capital repairs	473	452	427	330	449	487
Sagar Ratna	781	279	492	790	Dry dock			320	402	114
Sagar Kiran	185	Dry dock		705	842	414	239	637	645	347
Sagar Pragati	Dry dock	356	446	540	588	361	614	515	Rig decommissioned	
Sagar Shakti	151	328	171	392	585	347	395	510	930	479
Sagar Uday	272	205	166	459	NA	239	Dry dock		650	789
Charter Hire (CH) Rigs										
Avg. cycle speed of CH rigs	1,347	1,255	1,307	1,325	1,058	1,118	1,025	1,243	1,051	939

MOPNG (August 2015) did not comment on the subject. The Company stated in its supplementary reply (August 2015) that Sagar Uday and Ratna were pilot projects of sorts after formulation of the policy in 2007 and it was considered prudent to await completion of projects to validate the formulated policy. In view of the experience in these two projects, a need is felt to revisit the policy.

The supplementary reply of the Company is not acceptable as the proposal for major lay-up repair of third jack-up rig, Sagar Jyoti was mooted in 2009 much before completion of repair work of jack-up rigs, Sagar Ratna and Uday. While the Company's reply regarding need for revisiting the policy is appreciated, further delays in repairs would lead to further deterioration in condition of rigs and impact their efficiency.

6.1.2 Analysis to justify repair deficient

Following the policy (2007) for dry dock and major lay-up repair of departmental offshore jack-up rigs, the Company initiated individual proposals for repair of three rigs (Sagar Ratna, Sagar Uday and Sagar Jyoti). In each case, the Company carried out an analysis to justify the expensive repairs by comparing the cost of repair to the cost of hire and purchase. The net present value (NPV) of the three options (repair, hire, purchase) were worked out and evaluated.

Audit observed that inappropriate assumptions were made while comparing the three options:

(i) The Company assumed that the departmental offshore jack-up rigs would have a life of ten years following the repair. The assumption was not backed by residual economic life analysis. The Company (December 2004) had formed an in-house Committee to carry out age and efficiency analysis of rigs. The Committee had estimated that the economic life of jack-up rigs was 30 years and had recommended that a residual economic life estimate be done by a third party on completion of 25 years to assess the feasibility of obtaining extended life of the vessel.

Audit noticed that the rig Sagar Jyoti had completed 26 years when the proposal for repair was taken up. However, the cost benefit analysis of the repair option considered a ten year operation of the rig, post repair even though the economic life of such rigs had been considered as 30 years. The rigs, Sagar Ratna (procured in 1985) and Sagar Uday (procured in 1990), were also considerably aged by 2007 and their economic life ought to have been assessed before assuming a ten year operation post-repair.

(ii) The Company assumed that the efficiency of the repaired rigs would match the efficiencies of new as well as hired rigs. Audit observed that the efficiency of owned rigs had always been much lower than that of CH rigs. Over the ten year period 2003-13, efficiency (in terms of cycle speed) of comparable type and vintage CH rigs had been more than 2.52 times that of owned rigs. The external consultant (M/s Deloitte) hired to appraise the feasibility report for major lay-up repairs of rig Sagar Uday had also pointed out that the repaired rig may not operate at the same levels of efficiency as that of a new or CH rig.

Audit noticed that the proposal for repair of old rigs would not be considered economically viable vis-à-vis hire / purchase of rigs if realistic efficiency of the alternate options are considered as seen in the case of rig Sagar Uday given below:

Table 6.2: Cost benefit analysis of major lay-up repairs

Scenarios	Alternatives	NPV worked out by the Company considering equal efficiencies of owned and hired rigs in April 2009	NPV considering efficiency of hired rigs as 1.5 times that of owned rigs, as worked out by Audit
	Major cost Assumptions	Rig CH rate USD 154,375 per day	Rig CH rate USD 154,375 per day. Effective rig rate of USD 102,917 per day considering efficiency of hired rigs: owned rigs as 1.5:1
		Repair cost ₹ 365.09 crore with capex escalation of 6 *per cent* per annum.	Estimated repair cost ₹ 365.09 crore with capex escalation of 6 *per cent* per annum
		New rig cost USD 205 million	New rig cost USD 205 million (₹ 821.84 crore).
Scenario -1	Hiring of a substitute rig of similar capacity	₹ 820.93 crore	₹ 548.51 crore
Scanario-2	Major Lay-up Repairs cost of owned rig	₹ 564.42 crore	₹ 564.42 crore

(iii) Besides, Audit noticed that the Company was inconsistent in its assumptions as detailed below:

- The salvage cost of rigs was not considered in the cost benefit analysis of repair of rigs Sagar Uday and Sagar Ratna while it was considered at 50 *per cent* for new rig in the case of rig Sagar Jyoti.
- The dry dock expenditure was considered as capital expenditure with 30 *per cent* depreciation in the case of rig Sagar Uday. The same expenditure was considered as partly revenue expenditure in case of rigs Sagar Jyoti and Sagar Ratna and the capital component was depreciated at 15 *per cent.*

A uniform set of assumptions would improve the quality and transparency of the analysis.

The Company stated (April2015) that the major lay-up repairs/ up-gradation of rigs were done after carrying out cost benefit analysis of repair works *vis-a-vis* hiring of rigs/ purchase of new rig. A holistic view would prove that the cost of repair in case of all the rigs in the past was in favour of the Company considering the foreign exchange components and benefits in owning rigs which ensure better bargains in the day rates of charter hire.

Reply of the Company needs to be viewed in the context that the Company was itself aware of the shortcomings of the economic analysis justifying repair. This was seen in the internal comments of the Finance wing which had pointed out that the efficiency of the Company's owned rigs was considerably lower than that of the CH rigs and if this disparity in efficiency was considered, the proposal of repair of old rigs may not be a financially acceptable option.

MOPNG (August 2015) did not have further comments to add on this issue. During the Exit Conference (August 2015) with MOPNG, the Company assured that efficiency factor would be factored in the future cost benefit analysis of major lay-up repairs.

The Company in its supplementary reply (August 2015) added that dry docks of Sagar Uday and Ratna had time and cost over-runs and considering their first dry dock since inception it was observed that dry docking cost was in the range of 55-60 *per cent* of new rig. In view of this experience, it is being considered to review dry docking and major lay-up repair of the existing rigs so that minimal work is done to run these rigs for a short term of about 4-5 years and in the meantime to prepare a strategy for replacement of the old rigs.

Audit acknowledges the assurance given by the Company during Exit Conference and the acceptance of the fact of abnormal cost over runs during the repairs. Action of the Company will be watched in future audit.

6.1.3 Delay in finalisation of scope of work and tender leading to cost escalations

The scope of work for major lay-up repairs of rigs Sagar Ratna and Sagar Uday was prepared on the basis of defect analysis by a third party, M/s MODU spec, Singapore. The scope of work so prepared for rigs Sagar Ratna and Sagar Uday was also vetted by M/s NSRDC and M/s MODU spec respectively. Based on the scope finalised, tenders were invited and contract awarded to M/s Hindustan Shipyard Limited and M/s Larsen & Toubro Limited in August 2008 and July 2010, respectively.

Audit noticed that there were inordinate delays in finalising the scope of work and tender finalisation. The freezing of scope of work and tender finalisation took 36 months (rig Sagar Ratna) and 48 months (rig Sagar Uday). The scope of work for rig Sagar Jyoti was yet (May 2015) to be finalised even after six years (since 2009).

The rig, Sagar Jyoti had been commissioned during 1983. Following the major lay-up repair policy (2007), the rig was to be repaired in 2009. Audit noticed that the initial scope of work for major lay-up repairs could be prepared by the Company only in 2009.

Subsequently, the scope of work was changed in 2012, with a plan to use the salvage equipment of rig Sagar Ratna in order to optimize the cost of repair.

Audit noticed that the plan to use the salvage equipment of rig Sagar Ratna while changing the scope in 2012 was not in line with the equipment replacement policy which prescribes 20 years as age for such critical equipment. The proposal to use salvage equipment of rig Sagar Ratna which were more than 27 years old was also not justified since the cost of overhauling of these salvage equipment was 75-87 *per cent* of new equipment which was economically not a prudent option.

The deficient scope prepared in 2009 had contributed to delay in repair. The scope of major lay-up work of rig Sagar Jyoti was yet to be finalised (May 2015) (even after six years).

The delay in finalisation of scope was compounded by delay in handing over the rigs to the contractor for repair. The resultant delay led to further deterioration of the rig condition, increased the scope of repair work and consequent cost escalations.

The cost estimates for the repair were prepared in-house and were vetted by a third party, M/s IMU, Vizag. Audit noticed that the cost also escalated significantly from the time the Company decided to undertake repairs to the award and execution of the contract as detailed below:

Table 6.3: Cost escalation in execution of major lay-up repairs of own jack up rigs

(₹ in crore)

Sl. No.	Name of the rig	Cost estimated at the time of decision	Contract cost awarded	Cost of actual execution	Percentage increase	
					Contract with reference to estimate	Actual cost with reference to estimate
1	S/Ratna	228.82	361.07	586.78	58	156
2	S/Uday	365.09	376.91	572.48	3	57

The increase in cost and the altered rig market changed the relative economics of the repair and hire options. For example in April 2009, NPV (considering operation over a ten year period) of cost for repair of rig Sagar Uday had been worked out as ₹ 564.42 crore as against the NPV of hiring cost as ₹ 820.93 crore. By the time the contract was awarded in May 2010, the NPV for repair had risen to ₹ 664.95 crore as against the NPV for hire of ₹ 585.85 crore (the rig hire rates having declined substantially).

The rig, Sagar Ratna, had been released for major lay-up repairs in August 2009. The work was expected to be completed by May 2010. The completion of dry dock took over a years' additional time (excess time taken being 27 months) and cost increased by ₹ 225.71 crore (63 *per cent* increase over contract cost).

Audit noticed: that:

- Rig was in continuous operation for 25 years since commissioning without major lay-up repairs. As such procurement of critical spares became a major reason for delay.
- Indecision on the part of the Company regarding design of the Raw Water System contributed to further delay. The design was changed repeatedly accounting for a delay of 9 months.
- The scope of work had to be changed from overhauling of draw works, mud pump and crane equipment to replacement based on advice of OEM considering the cost of overhaul and technical obsolescence. As this decision regarding replacement was taken without stripping down the equipment, the same could have been done through the OEM at the time of preparing scope of work, thereby saving lead time in procurement of equipment.

Thus, even at the stage of award of the contract, repair of rig Sagar Uday was not the most economic option, rendering the exercise of cost benefit analysis before repair redundant. Even after award of the contract and handing over the rigs, the costs increased significantly as can be seen from the table 6.3. Audit noticed that the cost increases during execution of the contract was on account of expanded scope of work added during contract operation which also led to considerable delay in execution. As per the major lay-up repair policy of the Company, such changes in scope of work should be vetted by an independent, internationally accredited third party. Audit noticed that this was not done. Besides, the change in scope of work could have been anticipated by the Company as seen in the specific case of Sagar Ratna elaborated above.

The Company replied (April 2015) that orders had been taken with due approvals by the competent authority. The Company stressed that there were several activities, as per the laid down procedures, to reach the final stage of award. Compliance with these procedures along with their due interpretations resulted in actual time taken being larger than the norm. The Company also stated that due to continuous work requirement the rigs could not be taken out of cycle for major lay-up repairs as scheduled. Accepting the delays in finalisation of contract and resultant cost escalation, the Company stated that the present procedural framework requires a complete review. It was also stated that a stage gate process would be introduced for speeding up the project implementation. The Company assured that efforts have been made to review the existing framework to ensure that future projects were completed within scheduled time and cost.

The Company stated in its supplementary reply (August 2015) that the scope of work for the lay-up repair projects of rigs, Sagar Ratna and Sagar Uday were prepared based on the condition of the equipment and was duly vetted by a third party. However, as the scope of work is framed while the rigs are in operation, it is not possible to finalise the complete scope work. Only after dismantling of the equipment and systems, it is possible to know the exact nature of repair and the additional requirement of spares which result in change orders. Many change orders are due to additional spares / jobs that are required to bring the equipment/ system in functional order as per recommendations of OEM or classification agencies.

The assurance of the Company (April 2015) is noted. It may, however, be relevant to point out that delay in finalising scope of repair work had been noticed even earlier in the Company. The Internal Audit group of the Company had done a theme audit on dry docking of offshore rigs in 2009-10. This report had also highlighted the excessive time in finalisation of scope and repair of rig. It had been highlighted that incomplete assessment of scope of work led to delay in repair of rigs and increase in repair cost. The delay and the cost escalations pointed out in this internal audit report are tabulated below:

Table 6.4: Delay in major lay-up repairs and resultant cost escalation

Name of rig	Period of dry dock	Actual dry dock days	Excess days	No. of change orders	Additional cost (₹ in crore)	Contract cost (₹ in crore)
S/Pragati	3/04 to 7/06	852	590	NA	NA	NA
S/Kiran	3/06 to 10/08	945	620	282	55.51	217.69
S/Bhushan	10/06 to 9/08	696	580	650	57.24	91.77

Source: Theme Audit of dry docking of offshore rigs carried out by IA of the Company

There was, thus, a strong case for corrective action by the Company to avoid such delays and cost escalations.

Considering the experience of the Company, mandatory survey schedules, equipment replacement policy and the downtime of the equipment, much of the changes could have been avoided.

6.1.4 Performance of rigs after dry dock

During the dry dock and major lay-up repairs of rigs Sagar Uday and Sagar Ratna, obsolete equipment were replaced and systems were upgraded to the latest technology at par with industry standards. It was expected that repairs would lead to higher efficiency of the rigs in terms of cycle speed and commercial speed. Further, it was expected that the rigs would be deployed for exploration and development drilling rather than work-over jobs. Audit observed that performance of rigs post dry dock had not improved as envisaged. The performances of the two rigs, Sagar Uday and Sagar Ratna, before and after dry dock are tabulated below:

Table 6.5: Performance of rigs before and after dry dock

Cycle speed	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Sagar Uday	Rig was used for work-over operations				Dry dock	Dry dock	650	789
Sagar Ratna	492	790	Dry dock	Dry dock	Dry Dock	320	402	114
Avg. for offshore rigs			815	884	978	1116	863	994*

Source: Director T&FS Annual report **** Source: SAP Report***

As can be seen from the table above, the efficiency (expressed in terms of cycle speed) did not improve significantly after repair and consistently remained below the average for the Company. Deployment of the two rigs, post repair was also below expectations:

- Rig Sagar Uday had been used for work-over jobs before major lay-up repairs. As per the proposal for repair, the rig would be utilised for drilling exploratory and development wells including high tech/ horizontal and Extended Reach Drilling (ERD) wells, post repair. Audit noticed that after repair, the rig was mainly used for work-over operations. Only two exploratory wells had been drilled with the rig since 2013.
- The rig Sagar Ratna was to demonstrate an improvement in cycle speed post repair as per the repair proposal. Audit, however, noticed that the cycle speed dropped below even the pre-dry dock levels after carrying out major repairs at a cost of ₹ 586.78 crore.

The Company replied (April 2015), that rig Sagar Uday was capable of drilling exploratory wells, post dry dock. The rig had been deployed to work-over wells on account of priority given by the Assets. The Company explained the low cycle speed of rig Sagar Ratna as being due to loss of 65 days in 2012-13 on account of non-controllable activities. Besides, the Company pointed out that the rig Sagar Ratna was deployed in the east coast for exploration drilling where it faced difficult formations.

The reply of the Company was not acceptable in view of the following:

(i) Deployment of rig, post major repairs to work-over operations was not desirable, given that it goes against the objective for which costly repair of the rigs had been carried out. It was noticed that even during 2014-15, the rig Sagar Uday was used for work-over operations. Even during 2015-16, the rig had been mainly planned for work-over operations.

(ii) The cycle speed of Sagar Ratna did not improve even during 2013-14 and 2014-15. The speed of the rig was low even when compared to the average speed achieved by rigs in the east coast (as against the average cycle speed of 504 in the east coast, Sagar Ratna achieved a speed of 402 in 2013-14 and 114 in 2014-15.

MOPNG did not offer any further comments (August 2015). The Company in its supplementary reply (August 2015) stated that during 2013-14, Sagar Uday was deployed for drilling cycle for only 5.90 rig months. Out of these operational rig months, rig remained under repair for 1.33 Rig Months due to follow-up repairs immediately after dry-dock, which constituted 23 *per cent*. During 2012-13, the rig Sagar Ratna was deployed for drilling cycle for only 6.38 rig months of which the rig remained under repair for 1.31 rig months due to follow up repairs immediately after dry dock. The rig also encountered unexpected well activity while drilling leading to downhole complications. The well later had to be side tracked, resulting in lesser cycle speed. In 2013-14, the cycle speed suffered due to casing retrieval job under rig building phase (1.94 rig months) as well as longer production testing time (3.09 rig months). The repair time for rigs Sagar Uday and Sagar Ratna in 2014-15 was only 11.8 days and 9.9 days, respectively.

The reply of the Company needs to be viewed in the context of justification provided in the major repairs proposal of rigs Sagar Uday/ Ratna wherein it was stated that post repairs, the rigs would be on par with latest offshore drilling technology and international standards. However, the performance of the rig was much lower than average of charter hired rigs. Besides, the cycle speed of rigs is not affected by out of cycle days during the post dry dock repairs and, hence, cannot be said to affect the performance of the rig.

6.2 Dry docking and maintenance of Departmental drillships

6.2.1 Delays in dry dock of drillships

As per International Rule Requirement of the Classification Surveys, the Company had to carry out dry dock survey of its drillships (Sagar Bhushan and Sagar Vijay) twice in a period of five years. This was not strictly adhered to. Dry dock of drillships were delayed vis-à-vis plan. Delays were also noticed in actual execution of repairs which led to excess costs as can be seen in the case of rig Sagar Bhushan detailed below:

Rig Name	Delay	Reasons
Sagar Bhushan	As against scheduled date, the dry dock took 332 more days (2012-13).	• During the repair period, the surveyors activated SPS-5 survey[19] which was due by October 2012, without which the ship could not have sailed out. The proposal (June 2012) of dry dock cell for SPS-5 survey was approved by the competent authority *i.e.* Executive Purchase Committee and LOA was issued only on 29 Oct 2012 after expiry of scheduled completion date of repair. • Audit noticed that the SPS-5 survey was part of the initial package but was left out while awarding the contract. This led to avoidable delay in repairs. • The delay in repairs led to non-availability of the rig for drilling activities. This resulted in loss of six planned rig months. In the absence of S/Bhushan, the planned location assigned to it was drilled by deploying more expensive, higher capacity, deep water rigs in two different spells at an additional cost of ₹ 167.11 crore approx.[20].

While accepting the audit observation, the Company stated (April 2015) that its Board intended to implement the Stage Gate Process[21] for speeding up implementation for the forthcoming projects which was expected to address problems of delay. MOPNG in its reply (August 2015) stated that the assurance of the Company would be noted for compliance.

The action taken by the Company would be watched in future audit.

[19] ***SPS – Special purpose ship survey. The drillships are subjected to periodical surveys for the purpose of maintenance of class.***

[20] ***Actinia cost-US$ 209570*156 days *55= ₹179.81 crore.***
Noble Duchess cost- US$ 198452*31 days *55=₹33.84 crore.
Sagar Bhushan cost- ₹24.89 lakh per day * 187 days =₹46.54 crore.
Pending information, average cost per day of Sagar Bhushan was considered at 2008-09 level.
Exchange rate assumed as US$=₹55.

[21] ***Stage Gate Process is used to describe a point in a projector plan at which development can be examined and any important changes or decisions relating to costs, resources, profits, etc. can be made.***

6.2.2 Performance of drillships after up-gradation

The Company upgraded Sagar Vijay to water depth capability of 900 metres (1997-98) and Sagar Bhushan to 400 metres capability (2003). Audit noticed that these rigs were utilised only in shallow water (less than 400 metres water depth) during 2010-14 except a lone well in 2013-14. Further, despite regular dry docking, no marked improvement in their performance was noticed:

Table 6.6: Performance of drillships after upgradation

Cycle speed	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Sgar Bhushan	Dry dock		273	175	PT@ for 320 days	Dry dock	290	105
Sagar Vijay	196	227	Dry dock	422	226	Rig was under rig building (90 days), PT (167 days) & Capital Repairs (103 days)	309	Not indicated by the Company

@ PT-Production testing

The Company stated (April 2015) that after up-gradation to water depth capacity of 900 metres, Sagar Vijay had drilled 18 wells of which nine were in water depth of 500 to 900 metres. Likewise, after up-gradation in 1996-98, the rig Sagar Bhushan was capable of operating upto 400 metres. However, as no well between 300 to 400 metres water depth was required for drilling, Sagar Bhushan had not drilled any such well. The Company also stated that the rigs had undergone only dry docking and other mandatory surveys as per International Maritime Organization (IMO) regulations and no major capital repair of equipment was undertaken except some minor repairs. The Company had pointed out that the rig Sagar Vijay and Sagar Bhushan had been commissioned in 1985 and 1987 respectively and most of the equipment on the rigs were more than 27 to 29 years old and had outlived their useful lives. The Company asserted that considering the life of rig and present condition of equipment, the rigs were utilised to their optimum level. Besides, up-gradation and replacement of major systems and equipment of these two rigs had been initiated to improve their future performance.

The Company had accepted that the rigs were old and the equipment on board had outlived their useful lives. Audit, however, noticed that the proposal for replacement of major equipment on the rigs was yet (May 2015) to be approved and, hence, it was unlikely that the same would be replaced during the ensuing dry dock (Sagar Vijay in 2015 and Sagar Bhushan in 2016). Thus, both the rigs would continue to operate with lower efficiency. It was noticed that the rig Sagar Vijay had not drilled a single well with depth more than 400 metres during the seven year period (2006-13) and had taken up drilling of a single deep water location in 2013-14 which emphasises the inefficient deployment and operation of these rigs.

The Company in its supplementary reply (August 2015) stated that due to availability of Dynamic Positioning (DP) rigs since 2003, the DP rigs were deployed for deeper water operations considering their suitability of east coast environment. The Company's reply needs to be viewed in the context of high operating cost of these drillships as against their deployment. MOPNG in its reply (August 2015) did not offer any comments on this issue.

6.3 Delay in replacement of equipment on rigs

A. Delay in replacement of main engine of rigs

The rig equipment replacement policy of the Company (November 2008) laid down the schedule for replacement of equipment on rigs. The policy, *inter-alia,* provided that main engine, alternator, DC motor of the rigs need to be replaced after twenty years.

The rigs Sagar Vijay and Sagar Bhushan had been commissioned in 1985 and 1987, respectively and the main engine, alternators and DC motors on these rigs were well over twenty five years old when a decision (2014) was taken for their replacement. This was in contradiction to the rig equipment replacement policy of replacing the equipment after 20 years.

Audit noticed that overhauling of the main engines were delayed due to non-availability of spares. Besides, the spares were being made available by the OEM at a very high cost as they were custom made, the main engine having already become obsolete. Subsequently, in May 2014, it was proposed to replace the main engines which was yet to be approved. In the proposal, the Company had worked out the savings on replacing the main engine as being ₹ 11.06 crore per annum (due to reduced cost of operation and lower fuel consumption). Considering the lead time for procurement of the engines, it was unlikely that the engines would be replaced during the next dry dock (2015 for rig Sagar Vijay and 2016 for rig Sagar Bhushan).

The Company, while acknowledging (April 2015) that there had been delay in procurement of spares, stated that impetus rate contracts had also been put in place to expedite the spares procurement process. A number of capital equipment were under procurement and would be replaced during rig operation itself. The replacement of main engines and water makers were presently under procurement and would be replaced at the earliest available opportunity.

The reply needs to be viewed against the non-compliance with the Company's own rig equipment replacement policy of 2008 and continuance with obsolete equipment which had a higher cost of operation. MOPNG had no further comments to offer (August 2015).

B. Delay in replacement of water makers

All offshore rigs have water makers installed on them to cater the requirement of potable water as supply of potable water from base was costlier. Each departmental offshore rig had two water makers (one working and one standby). The life of the water maker was ten years as per the equipment replacement policy (November 2008).

Audit noticed that replacement of water makers was overdue in five out of eight offshore rigs. In four rigs (Sagar Shakti, Sagar Bhushan, Sagar Jyoti and Sagar Gaurav), the water makers were not functional at all and the entire potable water requirement was being met by supply from base through OSVs. In other two rigs also, the requirement of potable water exceeded the actual production and the shortfall was being met through supply from base. Supply from base was more expensive than production through water makers. Considering the rate of supply of potable water from base at ₹ 6 per litre (conservative estimates taken from the Company) and adjusting for the cost of production of potable water through water makers at ₹ 0.50 per litre (estimates of Company), the extra expenditure on supply of potable water from base during 2010-14 worked out to ₹ 70.89 crore. Besides, need to supply potable water to rigs added to the burden on marine logistics, especially OSVs which were not adequate for logistics supplies to the rigs for ensuring unhindered drilling operations.

The Company stated (April 2015) that water makers installed at rigs were designed to utilise heat generated by the power pack engines to produce potable water from sea water. Heat generation depends upon the availability of load on the engines which in turn depends on the operation being carried out at rig. Further, water was transported through supply vessels carrying regular provisions. When the potable water was pumped through bulk hoses, boat delivers the other rig materials like mud chemicals, store/spares *etc.* concurrently. Therefore, there was no time loss of boat/supply vessels in delivering the potable water and, thus, charter hire day rate of OSVs cannot be included in the cost of water supplied to rig. The Company further stated (April 2015) that replacement policy was not mandatory in case of working equipment/ where OEM support and spares were available. However, replacement of equipment as per need was already in process and these would be soon replaced.

The reply of the Company is not convincing. It is pertinent to note that the hired rigs cater to their own water requirement. Out of potable water supplies made by the Company to all the rigs during 2010-14, a meagre 3.1 to 7.8 *per cent* was supplied to CH rigs while the bulk 96.9 to 92.2 *per cent* was supplied to owned rigs. The Company had charged its contractors (May 2014) ₹ 6.48 per litre for supply of potable water through its vessels. Audit noticed that this rate (₹ 6.48 per litre) had been worked out based on costs alone without loading any profit margin. In fact, the Company charged a much higher rate (including a profit margin of 50 *per cent*) to others for supply of potable water. While working out the financial impact of supplying potable water from base, Audit had considered a conservative estimate of ₹ 6 per litre and also adjusted it against the actual cost of production of water by water makers.

MOPNG in its reply (August 2015) did not offer any comments on this issue.

6.4 Refurbishment and up-gradation of onland rigs

The capital repair and up-gradation of onland departmental rigs were done through BHEL and the Company's Central Work Shop (CWS) located at Vadodara. Audit scrutinised the capital repair jobs conducted by CWS during 2010-14. It was noticed that of the 27 repair jobs carried out by the Company during this period, only five were completed within the planned time (CWS plans 180 days for repair of drilling rigs and 150 days for repair of work-over rigs). In the remaining 22 cases, delays upto 181 days were noticed which impacted availability of rigs.

Audit noticed that delay in procurement of spares and delay in release of rigs by the Assets were the major contributing factors as indicated below:

- The capital repair of three rigs (BHEL 120-III, 120-IV and 120-VI) had been planned by CWS for the year 2010-11. CWS, however, placed the order for spares necessary for the repairs only in August 2010 which was received in June 2011. The capital repairs of these rigs had to be postponed for want of spares. Capital repair of BHEL-III and IV was finally delayed by two years while that of BHEL-VI was delayed by three years.
- Repair of the rigs, CW-700-II and BHEL-M-450-1 had been planned in the year 2009-10. Accordingly, CWS procured the spares necessary for repair of CW-700-II and BHEL-M-450-1, worth USD 0.95 million (₹ 4.59 crore, 1 USD = ₹ 48.33) in 2009. However, as the rigs were not released by the Asset, the actual repair of the rigs was carried out much later (in 2011-12 for rig BHEL-M-450-1 and 2012-13 for rig, CW-700-II). Similarly, though the spares for repair of rig M-750-II valuing USD 331,767 had been received in CWS in March 2011, the actual repair could be carried out only in 2012-13. In another case, spares valuing ₹ 3.10 crore for the work-over rig A-50-III had been procured in December 2009 but the actual repair was carried out only in 2011-12. Delay in release of rigs by the concerned Assets led to blocking up of funds with the CWS.

The Company stated (October 2014) that rig refurbishment time was dependent on various factors. One of the main factors was the condition of the rig on receipt. CWS procured overhauling spares and this did not include other type of components called insurance spares. The condition of such type of components were known only at the time of dismantling. CWS had to procure components/services which were not envisaged for replacement in regular refurbishment. Procurement of such components/services took time due to inherent intricacy of such type of components and procurement process. Secondly, the rigs were chassis mounted and needed complete chassis repair along with equipment mounted on chassis. Thirdly, all the rigs were very old, more than 20-25 years in operation and were continuously exposed to open atmosphere which reduced its life cycle. MOPNG in its reply stated (August 2015) that further steps have been taken to get the health check-up of all rigs through a third party agency and rigs have been categorized based on the need to refurbish or to lay off the rigs.

Reply of the Company needs to be viewed in the context that the insurance spares were needed to be kept at CWS as non-availability of these spare at CWS caused delay in majority of the cases. The proposed action as mentioned in MOPNG's reply would be watched in future audit.

Chapter 7: Conclusions and Recommendations

Conclusions

Drilling activities are key to hydrocarbon production and reserve accretion and constitute the single most significant operation of the Company, both financially and operationally. Efficient drilling operations depend on timely availability of suitable rigs and their efficient utilisation. To this end, the Company plans, hires and deploys rigs for drilling assignments. The Company also owns a fleet of rigs (both onland and offshore rigs) which needs to be appropriately maintained and up-graded to ensure efficiency of drilling assignments.

The planning horizon for rigs in the Company is five years. The production and reserve accretion targets of the Company are set for a five-year period which is the basis for working out the requirement of rigs over this period to facilitate timely hiring/ acquisition decisions. The Company based the five-year Rig Requirement Plan (RRP) on past experience in utilising rigs rather than on efficient norms of rig operation. This led to past inefficiencies being built into future plans. The rig days planned for the wells in the Rig Deployment Plans (RDPs) in Western Offshore were also higher as compared to the RRP during 2012-14 and resulted in 786 excess rig days for these wells. Though the Company has initiated an exercise to fix norms for drilling activities, onland development drilling alone has been covered so far, which is also not being uniformly adhered to. Hence, it appears that the ensuing plan also would not have the benefit of efficient norms.

The planning process is incomplete in so far as significant activities of side-track operations are not included in the five year plan though these activities consisting of 37 *per cent* (14,006 days) of the workload in western offshore area alone, are built in the RRP, creating an inconsistency in the planning process. Onland areas do not prepare a five-year rig requirement plan unlike offshore areas which adds to the incompleteness and inconsistency in the planning process. Besides, actual deployment of rigs was not as per plan, one-third of the locations (615 locations unplanned locations against 1,867 planned locations) that were actually drilled had not been planned in the annual plans.

There have been persistent delays (upto 508 days) in the tendering process for hiring rigs. Delay in hiring leads to non-availability of rigs for drilling operations (there was a loss of 391 rig months due to non-hiring of rigs on time during 2010-14). Significant delays in tendering process were often on account of delays in indenting, even in cases where the rigs were being re-hired. Besides, the Company was yet (May 2015) to firm up its policy regarding acquisition of new rigs though acquisition of offshore rigs was proposed in 2002 and most of its own offshore rigs have outlived their lives.

Rigs remained out of cycle for considerable periods *i.e.* 12 *per cent*, reducing actual availability of rigs for drilling by 679 rig months. Even after deployment, rigs idled on location. While a fraction of the non-performing time of the rigs was on account of non-controllable factors like weather, the bulk of idling time (valuing ₹ 6,418 crore) was well within the control of the Company and could have been addressed through better planning and coordination.

The efficiency benchmarks of rig operation, cycle and commercial speed were not appropriately fixed for Drilling Services group. While Drilling Services group adequately met these targets, the Company did not match up to its planned cycle and commercial speed for operating its rigs. The efficiency of Company owned rigs was poor with owned offshore shallow water rigs achieving less than half the cycle speed of hired rigs (the owned rigs achieved a cycle speed of 484 metres/month against 993 metres/month of hired rigs in 2013-14). However, while working out the cost benefit of repair and refurbishment of aged, owned rigs vis-à-vis hire/ acquisition, the Company considered their efficiency to be on par with hired and newly acquired rigs. Besides, significant delays upto 48 months in finalising the scope of work and tender and cost escalation was noticed upto 156 *per cent* with reference to rig repair estimates and the productivity of the rig, post repair did not match up to assumptions made at the time of deciding for repairs of such rigs.

The lapses of ONGC in planning, hiring, deployment and repair of rigs highlighted in the report had the following significant consequences:

- **Availability of rigs for drilling in ONGC was lower than intended on account of delays and deficiencies in the hiring process and rigs remaining out of cycle (over 2010-14, 1,070 rig months were lost on account of both these factors).**
- **Besides limited availability, the efficiency of rig operation was poor. The rigs that were deployed for drilling idled for considerable periods; bulk of the idling period was possible to be controlled by the Company. The inefficiency led to lower cycle speed and commercial speed of rigs, besides the Company incurring significant idling costs (₹ 6,418 crore).**
- **Owned rigs performed poorly vis-à-vis hired rigs. Cycle/commercial speeds of owned rigs were low while cost of their operation was high. Even as major repairs were carried out for owned offshore rigs, the financial viability of such repair remained doubtful. The post repair performance of owned offshore rigs also did not match up to assumption made. Poor performance of owned rigs contributed significantly to inefficiencies of rig operation.**
- **Measurement of efficiency of rigs was flawed. Inefficiencies were built in the plans (RRP and RDP) leading to a lower target of efficiency parameters (cycle speed). Even the lower targets were not achieved in actual operation. The performance of the Drilling Services group (responsible for operation of the rigs) was not measured against targets. In fact, the Drilling Services group met and exceeded their targets even as the Company failed to match up to its planned efficiency targets.**

Recommendations

1. The Company needs to ensure that the plans (five year plan, annual plan, rig requirement plan, rig deployment plan) are complete and consistent with each other. The Company should make efforts to adhere to the rig deployment plans during actual drilling. The situation where one out of every three wells drilled is un-planned needs to be corrected.

2. The controllable non-productive time of past periods should not be loaded to future rig requirement plans. With induction of new technology and hi-tech rigs, realistic targets for rig requirement ought to be set to have the desired stretch in performance. Suitable measures need to be taken to reduce the non-productive time of the rigs, particularly in eliminating rig waiting due to controllable factors like waiting for locations, ready drill sites, environment clearance, material, manpower and logistics support.

3. Initiation of indents and tendering procedure for acquisition/hiring of rigs, which are entirely within the control of the Company, needs to be done on time with proper planning so that rigs are mobilised on time. In particular, indents for re-hire of rigs on expiry of their existing contracts should be issued expeditiously so that the Company does not suffer from non-availability of rigs between the periods of de-hire and re-hire. Considering that most offshore rigs owned by the Company had outlived their useful lives, policy regarding acquisition of rigs, pending for over a decade, should be finalised expeditiously.

4. The cycle and commercial speed targets for Drilling Services group should be aligned with the planned cycle and commercial speed of the Company. Considering the very different activities carried out in offshore and onland and the consistently poor performance of owned offshore rigs, there is a need for setting separate targets for each category and adequately monitoring for attainment of such targets.

5. Efforts need to be made to correct the imbalance in drilling manpower at the cutting edge, necessary for efficient operations of owned as well as hired rigs. A suitable review of the current position needs to be taken up by the Company and the position rectified in a time bound manner.

6. The assumptions made while analysing cost-benefit of repairing old owned rigs, having outlived their useful lives, should be realistic, based on past experience, particularly with regard to efficiency expected of such rigs after repairs. This would enable a balanced decision regarding major repairs of these rigs.

MOPNG, while accepting (August 2015) all the recommendations, stated that the recommendations are for improvement of drilling performance and that the Company would be advised to follow all the recommendations of audit.

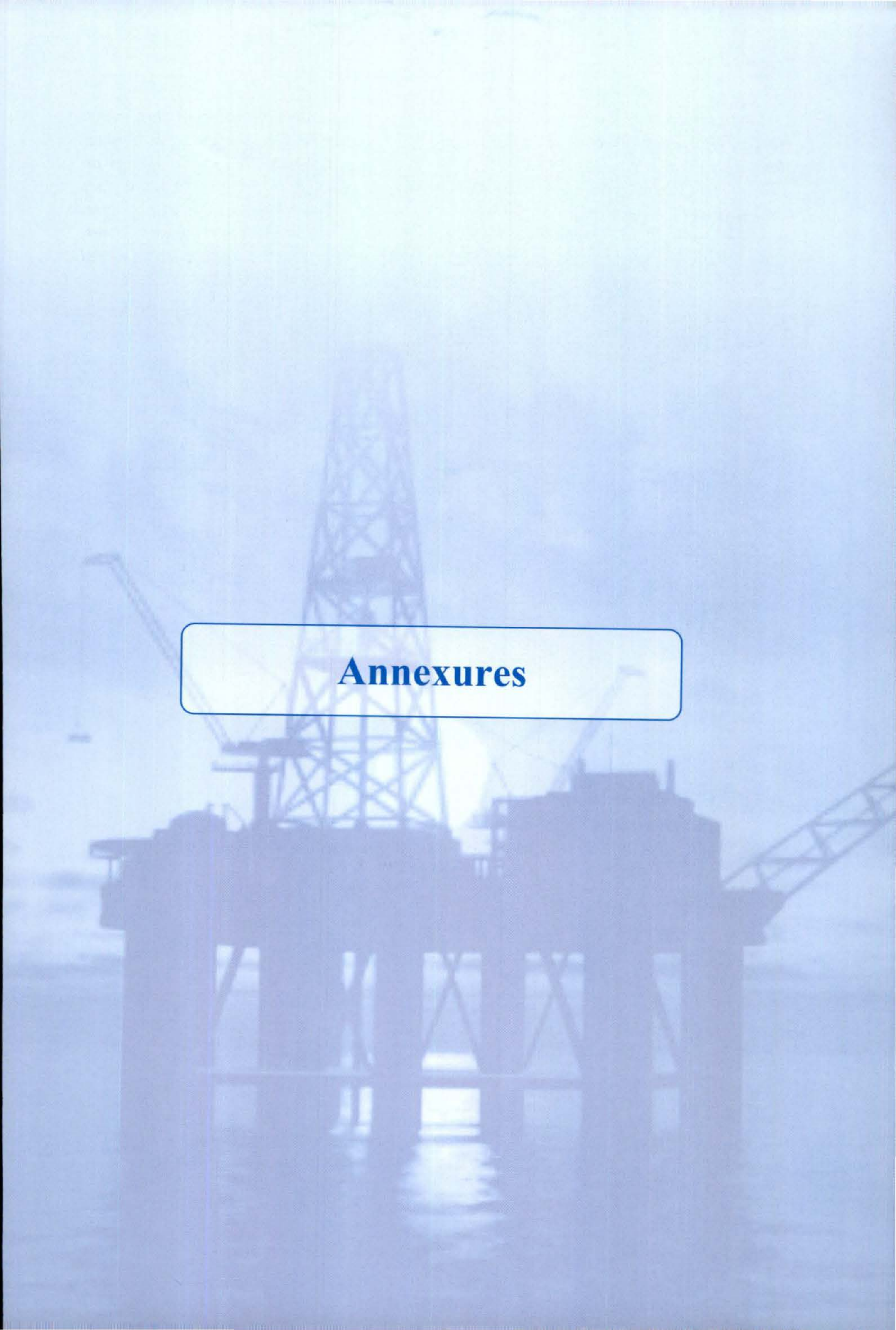
New Delhi
Dated : 13 November 2015

(PRASENJIT MUKHERJEE)
Deputy Comptroller and Auditor General
and Chairman, Audit Board

Countersigned

New Delhi
Dated : 13 November 2015

(SHASHI KANT SHARMA)
Comptroller and Auditor General of India



Annexures

Annexure I

Norms adopted for drilling different types of wells in XI and XII Five Year Plans

(Refer Paragraph 3.1-Inefficiencies in-built in the Five year RRPs.)

	XI FYP	XII FYP
Basins		
Shallow water-Exploratory wells		
Western Offshore Basins	4 RMs	4 RMs
Krishna Godavari	4.5 RMs	4.5 RMs
Mahanadi	6 RMs	-
Bengal Offshore	5 RMs	-
Assets		
Development well	50-65days	55 days
Marginal development well	60 days	-
Side track	40 days	47 days
MRDH/SRDH	25 days	-
WO	20 days	23 days
Rig Move	5 days	Included above

Annexure II

Exploration and Development locations planned versus drilled
(Refer Paragraph No. 5.1 – Significant deviation from rig deployment plan)

No. of Locations (As per RDP)				Total RE	Actually Drilled			Total Actual
Basin/ Block	BE	Planned in RE						
		Out of BE	New		From RDP(BE)	From RDP(RE)	New	
Offshore								
Shallow water Exploration	133	50	96	146	26	57	17	100
Shallow water Development	634	318	247	565	190	164	148	502
Deep Water	52	32	23	55	22	20	6	48
Total-Offshore	**819**	**400**	**366**	**766**	**238**	**241**	**171**	**650**
Onland								
Exploration	395	153	236	389	107	145	67	319
Development	782	222	602	824	207	314	377	898
Total-Onland	**1,177**	**375**	**838**	**1,213**	**314**	**459**	**444**	**1,217**
Total-ONGC	**1,996**	**775**	**1,204**	**1,979**	**552**	**700**	**615**	**1,867**

Glossary of Technical Terms

Sl. No	Technical Term	Meaning
1	Appraisal Wells	A well drilled to determine the extent or the volume of Hydrocarbon reserves and the likely production rate of the new oil or gas field.
2	Approved Work Programme and Approved Budget	A work programme or Budget that had been approved by the Company Committee pursuant to the provisions of Production Sharing Contract (PSC) entered into between the Government and the joint venture parties to the contract.
3	Asset	It refers to an entity that was involved in production activities from the existing wells and transportation of oil and gas on onshore plants.
4	Barrel	A quantity equivalent to forty two (42) United States gallons, corrected to a temperature of sixty (60) degrees Fahrenheit under one (1) atmosphere of pressure.
5	Basin	A Depression in the earth's crust where sedimentary materials are accumulated over the years. With reference to the Company it refers to the entity that was involved in exploration related activities.
6	Basin	Entity/ Unit involved in exploration related activities.
7	Block	Area identified in a field which was offered by the Government of India to prospective bidders under New Exploration Licensing Policy, for the purpose of exploration of oil and gas
8	Blow Out Preventer (BOP)	When primary control of a well was lost due to insufficient hydrostatic pressure, it becomes necessary to seal the well by some means to prevent the uncontrolled flow, or blow out, of formation fluids into the atmosphere or into an underground formation. The equipment which seals the well was called the blowout preventer.
9	Cantilever Rig	A jack-up drilling unit in which the drilling rig was mounted on two cantilevers that extend outward from the barge hull of the unit.
10	Carrier-mounted Rigs	These are also called mobile rigs for onland. In which rig was mounted on wheeled carrier. This carrier can be driven to the well site with all necessary hoisting equipment, engines and special telescopic mast as complete on truck unit. These rigs are for shallower depth wells.
11	Casing Pipe	Metal pipe inserted into a well bore and cemented in place to protect both subsurface formations (such as groundwater) and the well bore. A surface casing was set first to protect groundwater. The production casing was the last one set. The production tubing (through which hydrocarbons flow to the surface) would be suspended inside the production casing.

12	Classification societies	Classification societies are organisations that establish and apply technical standard in relation to the design, construction and survey of marine related facilities including ships and offshore structures. These standards are issued by the classification society as published rules.
13	Commercial Speed	Commercial speed was meterage drilled upto the bottom of drilling well/rig months from spud date to well completion
14	Cycle Speed	Cycle speed meterage drilled per drilling rig month during the complete period from release from earlier well and mobilisation to release for next well.
15	Deep water Area	Area falling beyond four hundred (400) metre isobaths.
16	Delineation well	Delineation well refers to the well drilled in unproved area to determine the boundaries or the extent of reservoir
17	Development	Following discovery, drilling and related activities necessary to begin production of oil or natural gas
18	Development Area	It was a part of the Contract area corresponding to the area of an Oil Field or Gas Field delineated in simple geometric shape, together with a reasonable margin of additional area surrounding the Field consistent with petroleum industry practice and approved by the Management Committee or the Government, as the case may be.
19	Development Plan	A plan submitted by the Contractor for the development of a Commercial Discovery, which had been approved by the Management Committee or the Government in terms of PSC.
20	Development Wells	These Wells are drilled within the proved area of an oil or gas reservoir after exploration had proved successful.
21	Directorate General of Hydrocarbon	An organization, established under the control of Ministry of Petroleum and Natural Gas for regulation of the hydrocarbon exploration and exploitation
22	Discovery	The finding of a deposit of hydrocarbon not previously known to have existed, which can be recovered at the surface in a flow measurable by conventional petroleum industry testing methods.
23	Drillships	Also used for deep-water drilling, these ship-shaped floating rigs move from location to location under their own power. These are capable of operating in more remote locations and require fewer supply boat trips than do semis. These are maintained on location via dynamic positioning systems, and most of the rigs currently under construction are drillships.
24	Dry Dock	The process of sending a rig to shipyard where the rig can be subjected to 100 % (out of water) inspection to undertake repairs, surveys in order to comply with the mandatory requirements/requirements of classification societies.
25	Effluent Treatment Plant	To process the effluent received from GGS/CTF installation before disposal of effluents as per pollution control norms.

		The critical equipment are Pumps and Tanks.
26	Exploration	Searching for oil and/or natural gas, including topographical surveys, geological surveys, seismic surveys and drilling wells
27	Exploration Period	Any and all periods of exploration set out in the PSC.
28	Exploratory wells	A well drilled to determine whether hydrocarbons are present in a particular area or structure.
29	Field	Oil Field or Gas Field or a combination of both as the case may be. In respect NELP blocks, the Contract Area in respect of which a Development Plan had been duly approved in accordance with provisions of the Production Sharing Contract.
30	G&G Data	Geological, geophysical and geochemical data.
31	Geo Technological Order	An order which indicates the well drilling plan in terms of days depth indicating lithology vis-à-vis depth, pressure vis-a-vis depth casing/cementing policy, mud requirement, bits required *etc.*
32	Hermetical testing	Hermetical testing refers to the closed cycle pressure testing of casings of wells completed by pumping water at steady rate to detect leakage before handing over the well for production testing
33	High Floor Mast & Sub Structure	These are higher capacity onland rigs. In this rig components are transported to new location with the help of trucks and heavy-duty trailers.
34	Hydrocarbon	In organic chemistry, a hydrocarbon was an organic compound consisting entirely of hydrogen and carbon.
35	Jack-up rigs	Used for shallow water drilling, there are two jack-up types; independent-leg jack-ups make up the majority of the existing fleet. They have legs that penetrate into the seafloor and the hull jacks up and down the legs. Mat-supported jack-ups wherein the mat rests on the seafloor during drilling operations. Cantilever jack-ups are able to skid out over the platform or well location, while slot units have a slot that fits around a platform when drilling development wells.
36	Lay-up repair	The process of sending a rig to shipyard where the rig can be subjected to inspection to undertake repairs and surveys in order to comply with the requirement of classification societies.
37	Modular offshore rigs	These are compact and light weight rigs and mainly used for work-over operations for offshore areas
38	Monetization	The process involved in bringing the hydrocarbon discoveries of a field/block to commercial stage.
39	New Discovery	A Discovery made after the Effective Date of the PSCs.
40	New Exploration Licensing Policy (NELP)	NELP was formulated by the Government of India in 1997-98 to provide a level playing field in which all the parties may compete on equal terms for the award of exploration

		acreage. This was for accelerating the pace of hydrocarbon exploration in the country through which various blocks including deep-water acreages were offered for competitive bidding.
41	Object	Object was an interval or section of a well which indicates a likely presence of oil/gas through drilling data as well as study of logs. This section was generally a reservoir under different sedimentary environments and holds hydrocarbon pools.
42	Offshore Supply Vessels (OSVs)	Any Barge, Boat or Ship that brings materials like water, casing pipes *etc.*, and personnel to and from the rig site to supply.
43	Platform Rigs	These are self-contained rigs that are placed on fixed platforms for field development drilling. Some are called self-erecting and can be rigged up in as little as a few days. Other larger units require a derrick barge to be installed and can take up two weeks to be rigged up. Once drilling was completed, the rig was removed from the platform.
44	Petroleum	Crude Oil and/or Natural Gas existing in their natural condition but excluding helium occurring in association with Petroleum or shale.
45	Production Testing	Tests in an oil or gas well to determine its flow capacity at specific conditions of reservoir and flowing pressures. This Phase occurs after successful exploration and development drilling from which hydrocarbons are drained from an oil or gas field.
46	Prognostication	The process of forecasting or estimating the hydrocarbon potential of an area.
47	Reservoir	A naturally occurring discrete accumulation of Petroleum
48	Reserve accretion	Addition of hydrocarbon reserves to the existing reserves through exploration
49	Rigs	It was an equipment used for drilling a well bore. There are various types of offshore rigs like jack-up rigs, floaters, Modular rigs *etc.* In onland, there are two types of rigs *viz.* mobile rigs and High Floor Mast / Sub structure types of rigs
50	Rig Days	No. of days for which rigs were in operation/available during a particular period.
51	Rig Month	Total no. of days for which rigs were in operation/available during a particular period.
52	Rig Moratorium/ Holiday Policy	Due to global shortage of offshore drilling rigs, the Government of India decided (July 2010) to give a 3-year *i.e.* 2008-10 drilling holiday or moratorium to E& P companies.
53	Sedimentary Basins	Sedimentary Basins are depressions in the earth's crust where organic matters are deposited.
54	Semisubmersibles	Used for deep water drilling, these floating rigs have

		columns that are ballasted to remain on location either by mooring lines anchored to the seafloor or by dynamic positioning systems. They are used for both exploratory and development drilling.
55	Shallow Water Wells	Wells of water depth less than 400 metres.
56	Spud	Process of starting the well drilling process by removing rock, dirt and other sedimentary material with the drill bit.
57	Side track wells	To drill a secondary wellbore away from an original wellbore, which saves re-drilling the top part of the hole. A side-tracking operation may be done intentionally or may occur accidentally. Intentional side tracks might by pass an unusable section of the original wellbore or explore a geologic feature nearby. In the bypass case, the secondary wellbore was usually drilled substantially parallel to the original well, which may be inaccessible due to an irretrievable fish in the whole, or a collapsed wellbore.
58	Well	A borehole, made by drilling in the course of Petroleum Operations, but does not include a seismic shot hole.
59	Work Programme	A work programme formulated for the purpose of carrying out Petroleum Operations
60	Work-over operations	Operations on a producing well to restore or increase production. A work-over may be performed to stimulate the well, remover sand or wax from the wellbore to mechanically repair the well or for other reasons

List of Abbreviations

Sl. No	*Abbreviations*	Description
1.	A&AA	Assam & Assam Arakan Basin
2.	AC-VFD	Alternate Current-Variable Frequency Drive
3.	BE	Budget Estimates
4.	BEC	Bid Evaluation Criteria
5.	BOP	Blow Out preventer
6.	BOPD	Barrels of oil per day
7.	CRC	Corporate Rejuvenation Campaign
8.	CWS	Chief Well Services
9.	DS-MR	Drilling Services group– Mumbai Region of ONGC
10.	EC	Executive Committee
11.	EC	Environmental Clearance
12.	EDR	Effective Day Rate
13.	EOI	expression of interest
14.	EPC	Executive Purchase Committee
15.	FYP	Five Year Plan
16.	GTO	Geo Technical Order
17.	HPHT	High pressure /high temperature
18.	ICB	International Competitive Bids
19.	ICE	Information Consolidation for Efficiency
20.	IDT	Institute of Drilling Technology
21.	ILM	Inter-Location Movement
22.	IMO	International Maritime Organization
23.	JRMs	Joint Review Meeting
24.	KPIs	Key Performance Indicator
25.	LD	Liquidated Damages
26.	LOA	Letter of Award
27.	MBA	Mahanadi, Bengal and Andaman Basin
28.	MDT	Multi-Disciplinary Team
29.	ML	Mining Lease
30.	MM	Material Management
31.	MOPU	Mobile offshore production unit
32.	MRDH	medium radius drain hole

33.	MWP	Minimum Work Programme
34.	NELP	New Exploration Licensing Policy
35.	NIT	Notice inviting tender
36.	NPT	Non Productive Time
37.	NPV	Net Present Value
38.	ODR	Operating Day Rate
39.	OEM	Original Equipment Manufacturer
40.	ONSG	Onshore Services Group, Vadodara
41.	PAC	Project Appraisal Committee
42.	PEL	Petroleum Exploration Licence
43.	PSV	Platform Supply Vessel
44.	PT	Production Testing
45.	PW	Potable Water
46.	R&U	Refurbishment & Up-gradation
47.	RDP	Rig Deployment Plans
48.	RRP	Rig Requirement Plan
49.	RE	Revised Estimates
50.	RM	Rig month
51.	SDMM	Steerable down hole mud motor
52.	SLA	Service Level Agreement
53.	SOBM	Synthetic Oil Base Mud
54.	SRDH	short radius drain hole
55.	T&FS	Technology and Field Services
56.	TC	Tender Committee
57.	TBO	Technical Bid Opening
58.	TDS	Top Drive System
59.	TPI	Third Party Inspection
60.	UIIC	M/s United India Insurance Company Limited
61.	WMs	Water Makers
62.	WOB	Western Offshore Basin