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.

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[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***