Chapter 3
Audit Findings on Measurement and Reporting in Offshore Assets

The three Western Offshore Assets of ONGC (Mumbai High, Neelam Heera, Bassein & Satellite) account for nearly the entire offshore production of crude oil. Audit observed the following issues in the crude oil measurement and reporting systems in the Western Offshore Assets:

3.1. Reporting of 'condensate' as crude

ONGC included 'condensate' production in 'crude oil' production. 'Condensate' constituted 7.07 *percent* of the reported 'crude oil' production during the period from 2010-11 to 2014-15.

Section 3(b) of the PNG Rules 1959 and Section 2(e) Oil Industry (Development) Act, 1974 define 'crude oil' as *"petroleum in its natural state before it has been refined or otherwise treated but from which water and foreign substances have been extracted"*. 'Condensate', as defined by ONGC[10] is "*liquid hydrocarbons produced with natural gas, separated by cooling and other means*". 'Condensate' is thus, distinct from 'crude oil', by definition.

Besides, 'condensate' is produced from gas fields unlike 'crude oil' produced from oil fields. Not only is the production process of 'condensate' different, its utilisation in ONGC is also different from that of crude oil. While 'crude' oil is sold to refineries, 'condensate' is not sold and is used internally by the Company for manufacture of value added products.

Audit also noticed that the domestic Joint Ventures (in which ONGC has a participating share, e.g., JV operating the Tapti field) reported 'condensate' production separately.

International consultants, M/s DeGolyer and McNaughton (D&M), appointed by ONGC in 2011-12, had pointed out that 'condensate' is reported as a separate stream wherever there is a gas processing plant. Considering that ONGC has separate gas processing plants at Uran, Hazira and Gandhar, where its 'condensate' is received and processed, 'condensate' ought to have been reported as a separate stream.

Audit also noticed that whereas ONGC treats 'condensate' as natural gas while paying royalty to Government on its production, it reports 'condensate' as 'crude oil' production. By inclusion of condensate in crude oil production, Company had to bear an additional subsidy burden of ₹16331.96 crore as discussed in Para 5.2 A.

By definition, condensate is separate from crude oil. Production and utilisation of both products are also distinctly different. Company itself had admitted (July 2012) to the

[10] Annual Report of ONGC.

Ministry that condensate is not crude oil nor is it sold and requested for exclusion of condensate quantity from crude oil production (reckoned for under recovery burden).

Management/Ministry in reply (January/April 2016) stated that natural gas condensate is included in the crude oil production target fixed for the Company in the annual MoU signed with the Ministry of Petroleum and Natural Gas (MoPNG). Therefore, reporting is being done on like to like basis. Further, MoU parameters are under the purview of Task Force (constituted by Department of Public Enterprises (DPE) for negotiating MoU) and have been evolving over the years.

The reply of the Management/Ministry is not acceptable in view of the following:

(i) The Company had been reporting condensate production as a separate stream till 1989-90 and reporting condensate as crude oil production commenced only later.

(ii) The reply is also silent regarding non adherence of the Company to international reporting practices as well as the divergence of the Company's reporting practices vis-à-vis other domestic oil and gas companies.

3.2. 'Off-gas' reported as crude

Partially stabilised crude oil dispatched from the offshore platforms is stabilised at the Uran plant. At Uran, it is stabilized at the Crude Stabilisation Unit (CSU) which, *inter alia*, separates the dissolved gas in crude oil. This separated gas is the 'off gas' which is then added to gas stream. Inclusion of 'off gas' in the reported crude production has resulted in over reporting of crude oil production by the Company. During the period from 2010 to 2015, 'off gas' production accounted for one *per cent* of the reported crude oil production of the Company.

Audit also noticed that the Company pays royalty to the Government on 'off-gas' production at rates applicable for natural gas even though the quantum of production is included under crude oil production. By inclusion of off-gas quantity in crude oil production Company had to bear an additional subsidy burden of ₹ 2294.78 crore as discussed in Para 5.2 A. The additional payment of Performance Related Pay (PRP) to Company's employees by inclusion of off-gas quantity in reported crude oil production is discussed in Para 5.1.

Ministry stated (April 2016) that, had the processing facilities been available at the platform for complete stabilization, this gas would have been liberated at the platform and would have formed part of gas production and accordingly royalty was paid as gas. Management has also requested (January 2016) Audit to take up the issue with the Government for exclusion of CSU off-gas for determination of Company's share of under recoveries.

Ministry's reply is not acceptable, as in the absence of sufficient processing facilities at offshore, the partially stabilized crude inclusive of dissolved gas is despatched to Uran plant where off-gas is liberated during stabilization and added to gas stream and royalty is paid as 'gas' for this quantity of off-gas. Including the same in crude production has resulted in over reporting of crude oil production. As off-gas is reported as crude oil production, it adds to the Company's liability for sharing under-recoveries leading to higher burden of under recovery to be borne by the Company.

3.3. 'Basic Sediment and Water (BS&W)' reported as crude

Partially stabilised crude dispatched from offshore platforms and measured for reporting production of crude oil includes BS&W which is removed during the stabilisation process at Uran plant. During the period from 2010 to 2015, BS&W included in crude oil production accounted for 3.9 *per cent* of the reported crude oil production of the Company.

Section 3(b) of PNG Rules, 1959 and Section 2(e) of the Oil Industry (Development) Act, 1974 define crude oil as *"petroleum in its natural state before it has been refined or otherwise treated but from which water and foreign substances have been extracted"*. The Performance Contract[11] by which the Company sets crude oil production targets for individual Assets defined crude oil production as '*crude oil would include the portion of recoverable oil reserve that is produced and delivered at the custody transfer/delivery meter. It includes the quantity after adjustment of Basic Sediment and Water (BS&W)*'. At the custody transfer point (point of sale to refineries), the crude oil should have less than 0.2 *percent* of BS&W as per Crude Oil Sales Agreement signed by the Company with the refineries. Thus, the actual quantum of crude oil would be after adjustment of BS&W which has not been done by the Company in reporting production. Audit also noticed that the domestic Joint Ventures (where ONGC has participating interest, e.g., PMT-JV, Rava-JV, RJ-ON-90/1 JV) report production of crude oil excluding BS&W. The additional payment of Performance Related Pay (PRP) to Company's employees by inclusion of BS&W quantity in reported crude oil production is discussed in detail in Para 5.1.

Management/Ministry in reply (January 2016/April 2016) stated that complete processing/ stabilisation of crude oil is not practically feasible at offshore platforms, primarily because of space constraints. The partially stabilised crude is transported to land terminal for final processing to meet customer specification. Deduction made in crude oil production based on samples to compensate for free water and BS&W are not very accurate and leads to additional BS&W draining at Uran end. The methodology followed for reporting of production is with the objective of reporting production exclusive of BS&W. It was also highlighted that the definition of crude oil as per PNG Rules under Oilfields Regulation and Development Act is from the point of view of payment of royalty and these statutory provisions do not pertain to reporting requirement.

[11] Performance Contract is an annual contract signed by the Chief of Strategic Business Units (SBU) with the concerned Director. The performance evaluation of SBU is done based on actual achievement vis-à-vis target set for Key Performance Indicators. The methodology followed for evaluation of MoU signed by the ONGC with MoPNG is adopted for this purpose.

The reply of the Management/Ministry is not acceptable in view of the following:

(i) Though the reply asserts that the objective of the reporting methodology is to report crude oil production exclusive of BS&W, a significant quantum of BS&W is reported as crude oil production (accounting for 51,69,136 MT of reported crude oil production during the period from 2010 to 2015) which has contributed to over-reporting.

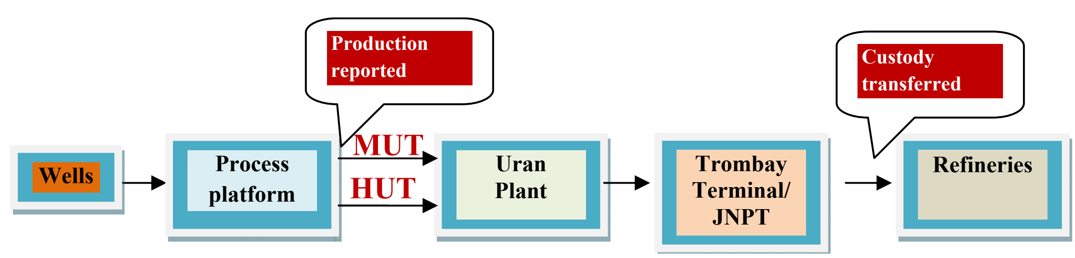
(ii) The crude oil production target fixed in the MoU signed with the Ministry does not indicate that crude production is inclusive of BS&W. In the absence of an alternate definition of crude oil for the purpose of reporting, the statutory definitions of crude oil (as per the OID Act and PNG Rules) ought to be applicable.

(iii) It is also pertinent to mention that the domestic JVs in which the Company is a partner, report crude oil production exclusive of BS&W. In fact, ONGC itself used to report crude oil production exclusive of BS&W till 1988-89 following which the process was changed. Even at present, crude oil production is reckoned excluding BS&W in the Company for high seas sale through FPSO. The reporting practice in the Company is thus inconsistent with its own practices as well as methodology followed by other oil and gas companies in the country.

3.4. Significant differences in reconciliation of crude oil

High seas sales of crude oil account for 7.90 *percent* of crude oil production from offshore areas with the balance transported through pipelines. Flow diagram of crude oil production and delivery in the pipeline sector of Mumbai offshore fields (with two major trunk lines, **MUT**: Mumbai Uran Trunk line and **HUT**: Heera Uran Trunk line) is depicted below:

Figure-4: Flow diagram of offshore crude oil production to sale point-pipeline sector



The difference in production quantity reported at the outlet of offshore platform and quantity sold at custody transfer point was examined in Audit. The results of analysis are given below:

Table-2: Reconciliation of pipeline sector of dry[12] crude oil at 15°C

(in percent)

Sectors where differences were noticed	2010-11	2011-12	2012-13	2013-14	2014-15
Difference between quantity reported at outlet of offshore and receipt at Uran inlet	9.37	8.33	4.17	4.63	4.43
Difference between quantity reported at inlet of Uran and outlet at Uranrepresenting stabilization of crude oil	0.07	0.23	0.42	0.62	1.23
Difference between Uran outlet and custody transfer point	0.36	0.06	0.21	0.40	0.22
Total differences noticed	**9.80**	**8.62**	**4.80**	**5.65**	**5.88**

As seen from the table above, the overall differences which had reduced to 4.80 *per cent* in 2012-13 has since increased in 2013-14 and 2014-15. Audit also noticed that the differences in 2015-16 (upto August 2015) were 5.93 *per cent* which confirms the increasing trend. It is also seen that the most significant differences arise in the transport of crude oil from offshore platform to Uran plant through pipelines. In contrast, the processes at Uran plant lead to minor differences and transfer from Uran to custody transfer point results in insignificant differences in dry crude oil quantity.

Management/Ministry replied (January/April 2016) that the oil from offshore is not fully stabilized and also not free from emulsified water due to footprint constraints. De-emulsifiers get more retention time while oil travels from offshore to Uran via long subsea pipeline resulting in breakage of residual emulsion. Final phase of separation and stabilization is attained while processing at Uran. It was further stated that the reconciliation difference is a result of inaccuracies in water content measurement and metering and to overcome these inaccuracies Standard Operating Procedures (SOPs) on metering and measurement of crude oil has been prepared and issued to all offshore assets for implementation.

The reply of the Management/Ministry needs to be viewed in light of the following:

(i) The major quantity difference occurs during transport of crude oil from offshore platforms to Uran plant, in closed pipelines. In comparison, the quantity differences at Uran plant, where stabilization processes actually take place, are minor.

(ii) In view of the very significant reconciliation difference, Audit tried to ascertain efforts taken by the Management for review and corrective action. In response, Uran plant and Assets stated that such reconciliation meetings are held on need basis but minutes of such meetings are usually not issued

[12] In case of offshore crude oil production dry crude oil denotes wet crude oil dispatched from offshore to Uran adjusted for water count in wet crude oil based on laboratory test done at offshore.

and are not available. In the absence of records, Audit could not ascertain the reasons for differences nor draw assurance that adequate steps were being taken by the Company for corrective action.

(iii) Management has accepted that metering and measurement of crude oil and water content has been inaccurate and assured that SOPs have been prepared for corrective action. The action of the Management would be reviewed in future audits.

3.5. Differences in reconciliation for pipeline transfer between offshore fields and Uran

Audit carried out detailed analysis of reconciliation of differences in the light of significant differences during transfer of crude oil between offshore platforms and Uran plant. It was noticed that the offshore platforms and Uran inlet are connected through closed subsea pipelines, viz., Mumbai Uran Trunk line (MUT) and Heera Uran Trunk line (HUT) line. Since the transfer is through a closed pipeline system, it is expected that the quantity of fluid (Crude+water+dissolved gas) dispatched from offshore and that received at Uran should tally. The monthly dispatch through Mumbai Uran Trunk line (MUT) and Heera Uran Trunk line (HUT) for one-year period from August 2014 to August 2015 was analyzed in audit. The results of analysis are tabulated below:

Table-3: Differences in wet crude oil receipt and dispatch

(in cubic meters at temperature of 15^{o} Celsius)

Date	MUT				HUT			
	Offshore dispatch	Uran receipt	Difference		Offshore dispatch	Uran receipt	Difference	
	M^3	M^3	M^3	%	M^3	M^3	M^3	%
Aug-14	8,25,342	7,96,378	28,964	**3.51**	5,99,031	5,83,439	15,592	**2.60**
Sep-14	8,05,575	7,66,011	39,564	**4.91**	5,85,175	5,66,894	18,281	**3.12**
Oct-14	8,05,054	7,69,406	35,648	**4.43**	6,01,074	5,81,127	19,947	**3.32**
Nov-14	8,08,756	7,72,783	35,973	**4.45**	5,93,772	5,70,678	23,094	**3.89**
Dec-14	7,43,409	7,14,455	28,954	**3.89**	5,81,010	5,57,305	23,705	**4.08**
Jan-15	8,35,592	7,96,061	39,531	**4.73**	5,90,262	5,68,646	21,616	**3.66**
Feb-15	7,67,818	7,35,974	31,844	**4.15**	5,28,355	5,08,708	19,647	**3.72**
Mar-15	8,61,441	8,22,608	38,833	**4.51**	5,52,189	5,31,392	20,797	**3.77**
Apr. 15	8,23,367	7,91,660	31,707	**3.85**	4,67,987	4,57,361	10,626	**2.27**
May-15	8,49,233	8,09,459	39,774	**4.68**	5,44,778	5,23,463	21,315	**3.91**
Jun-15	8,55,317	8,11,114	44,203	**5.17**	5,13,798	5,06,394	7,404	**1.44**
Jul-15	10,46,719	9,96,539	50,180	**4.79**	3,77,988	3,66,974	11,014	**2.91**
Aug-15	10,40,076	9,79,540	60,536	**5.82**	3,88,857	3,87,779	1,078	**0.28**
Average	**1,10,67,699**	**1,05,61,988**	**5,05,711**	**4.57**	**69,24,276**	**67,10,160**	**2,14,116**	**3.09**

As seen from the table above, there was an average difference of 4.57 *per cent* (MUT) and 3.09 *per cent* (HUT) between quantity dispatched and quantity received. It was also seen that the quantity reported at the offshore process platform were consistently higher than that reported at Uran inlet. Considering that measurements at both ends (offshore outlet and Uran inlet) were done at identical conditions of temperature (15^{o}C), and the fluid travelled in a closed pipeline, such significant differences were not expected.

The American Petroleum Institute (API) standard 2560 on "Reconciliation of Liquid Pipeline Quantities" states that for pipeline systems, '*there is **no actual physical gain or loss,** just simply small measurement inaccuracies (a fraction of percentage) and is caused by small imperfections in a number of measurements in the system'*. The standard also states that '*most pipeline systems typically experience some degree of loss or gain over time representing normal loss/gain performance for a system. However, such loss/ gain should be monitored for any given system at regular intervals to establish what is normal for that system and to identify any abnormal loss/ gain so that corrective action can be taken'.* The standard, thus, asserts that changes in quantity due to pipeline transfers are not expected and in case of differences, their cause ought to be analysed to identify whether it is abnormal and corrective action taken. In the instant case, the differences noticed are of the order of 3 to 4.5 *per cent* as against the fraction of a percentage difference expected as per the standard and hence abnormal. Considering the significant difference between the dispatch and receipt quantity, it is imperative that proper controls and monitoring is in place. API standards suggest that such differences in pipeline quantities could be due to *leakages, manual error in recording data or machine errors*.

Mumbai High and Neelam Heera Assets confirmed that there were no reported leakages of subsea trunk lines during the period of audit. The calibrations of meters were also checked by Audit and its impact was not found significant enough to explain the wide and consistent variations noticed. Human error is thus likely to be a reason for the un-explained differences in quantity.

Management in reply (January 2016) stated that:

(i) The API standard 2560 is not intended for non-liquid or mixed phase system. MUT and HUT pipelines are not single phase flow because of liberation of some gases between offshore and Uran over the 200 kms long pipeline. The API standard does not establish industry standards for loss/gain level because each system is unique and exhibits its own loss/gain level and/or patterns under normal operating conditions.

(ii) Minor meter imbalances or recurring hourly shortages/overages can be the result of pipeline pressure change, product interfaces, seasonal temperature changes, evaporation and volume shrinkage and thus, reasons for variation cannot be fully attributed to human error and machine error, as concluded by Audit.

The reply of Management needs to be viewed in the context of the following:

(i) The contention of the Management that transportation in MUT and HUT pipelines is not a single phase flow because of liberation of gases between offshore and Uran is not accurate. Management had appointed a consultant M/s IHRDC, Boston, USA (IHRDC) in October 2003 to study the reconciliation differences who had concluded that '*the crude oil in the offshore pipelines is above its bubble point at all times between the offshore and onshore meters. Break-out of gas cannot occur and therefore is not a factor in metering discrepancies and there is no product phase change between the meters'*.

(ii) Management has explained the reasons for minor differences between pipeline dispatch and receipt. However, the actual differences noticed are significant at 3 to 4.5 *percent*.

Ministry added (April 2016) that typical accuracy ranges for various metering purposes vary as per requirement and the metering at platform is mainly for production operations and not custody transfer grade. Ministry also pointed out that as per IHRDC, typical accuracy range for production purposes ranges at +/- 5 *per cent*.

The reply of the Ministry is not tenable. The typical accuracy range of +/- 5 *percent* quoted in the response, was suggested by IHRDC in its report of 2003, when the temperature at which measurement was recorded at both ends of the pipeline (offshore outlet and Uran inlet) was different. IHRDC had in fact recommended that, if temperature compensation is applied and meters were proved (calibrated), then differences ought to be within a percentage point or two. Presently volumes are measured at standard temperature (15^{o} C) at both ends (offshore despatch/Uran inlet) and thus the differences are expected to be much lower than the quoted +/- 5 *percent*. It is also pertinent to mention that for all days of the year (August 2014 to August 2015), there was a short receipt of crude oil at Uran when compared with the dispatch from offshore (not +/- scenario as suggested in the response).

The consistent losses, noticed during transportation of crude oil in a closed pipeline cannot be explained as typical inaccuracy of metering. Besides, the differences arising in the pipeline sector are significant; there being a difference of 7,19,827 cubic meters of reported crude oil production during transportation in the MUT and HUT pipelines for a year (August 2014-August 2015) alone.

3.6. Measurement of crude oil at offshore platforms

At the offshore platforms, measurement of quantity of crude oil dispatched is done using Turbine Meters and Auto Samplers. While Turbine Meters measure the quantity of partially stabilized crude (wet crude) pumped into the pipelines (MUT and HUT), the Auto Samplers measure the water content in the crude. To arrive at the actual quantity of crude oil dispatched (dry crude), the wet crude has to be adjusted for the water content. The cumulative quantity of dry crude dispatched from offshore platforms is reported as production of crude oil by the Company.

A. Non-availability of electronic/physical logs/records relating to measurement of wet crude by Turbine Meters at Offshore platforms

As already highlighted in Para 3.5, the wet crude measured at offshore platforms is consistently higher than the receipt at Uran inlet. Measurement at both ends is done using Turbine Meters (TMs). The measured quantity of wet crude by TMs is displayed by the Human Machine Interface (HMI) system on a real time basis. The readings from HMI is then read manually every day at 6.00 am and an Excel sheet containing the daily production details is prepared and manually entered in the SAP system. The standard volume[13] is taken from HMI and SAP uses a preset formula for final calculation of dry crude oil (based on water cut as measured by the Auto Samplers and density as reported by offshore lab) which is considered for reporting purposes.

Audit observed that electronic/physical logs/records of production data is not maintained at offshore and hence no audit trails were available to verify the correctness and integrity of data manually read from the HMI. While the flow computers have provision for storing logs for a period of 35 days, storing data for a longer period was possible by linking the flow computers with HMI with limited modifications. Audit observed that this was done at Uran plant where crude oil receipt data is maintained on hourly/daily/monthly basis for a minimum period of ninety days. Besides, the production data from HMIs is recorded in daily log sheets, maintained manually. Thus audit trails both electronic and physical, existed at Uran inlet. Audit test checked the records maintained at Uran end for the period January to August 2015 against electronic logs of HMI, physical daily log sheets, tank logs and SAP data and found them tallying. In the absence of logs/ audit trail for offshore dispatch quantity, reasonable assurance regarding accuracy of the recorded production figures at offshore could not be obtained by Audit.

Management in reply stated (January 2016) that subsequent to audit observations, necessary modifications and up-gradation of software in flow computers and HMI has been taken up at both Mumbai High and Neelam Heera Assets. Management also informed that post modification, back up of data would be available for over six months for Neelam Heera and longer periods for Mumbai High. Management also assured that post up-gradation, all the relevant audit trails will be available in the system. Ministry further stated (April 2016) that steps were being taken to integrate SCADA system with ICE SAP-ERP to address the issues brought out by Audit.

Audit has noted the corrective action taken by the Management and it will be verified during future audits.

[13] Volume at 15 degree Celsius /60 degreeFahrenheit

B. Differences in measurement of water content by Auto Samplers at offshore platforms

The water content in the partially stabilized 'wet' crude dispatched from the offshore platforms is measured by taking periodic samples of the 'wet' crude from the Auto Samplers and testing these samples chemically for water content at the offshore laboratory. An identical measurement process is followed at Uran plant where the water content at Uran inlet is measured based on Auto Samplers installed there. The net quantity, after adjusting the water cut is recorded as 'dry' crude dispatched and received at offshore and Uran respectively.

Audit noticed that the water content in the crude oil measured at receipt end (Uran inlet) has been **consistently higher** than that measured at the dispatch end (offshore platforms) during the period January 2015 to August 2015 as can be seen from the table below:

Table-4: Water cut in crude oil at offshore and Uran
Water Cut (WC) expressed as percentage of crude oil

Month, 2015	HUT pipeline (in per cent)				MUT pipeline (in per cent)			
	WC at Offshore	WC at Uran	Diff.	Diff. in %	WC at Offshore	WC at Uran	Diff.	Diff. in %
January	2.26	3.70	1.44	63.27	2.35	2.56	0.21	8.94
February	2.58	4.02	1.44	55.81	2.05	2.64	0.59	28.78
March	2.53	3.98	1.45	57.31	2.00	2.92	0.92	46.00
April	2.94	4.98	2.04	69.39	1.96	3.15	1.19	60.71
May	2.10	4.59	2.49	119.05	2.01	3.11	1.10	54.73
June	2.69	4.95	2.26	84.01	2.06	2.52	0.46	22.33
July	1.97	3.16	1.19	60.41	2.40	3.19	0.79	32.92
August	2.59	3.53	0.94	36.29	2.32	3.54	1.22	52.59
Average difference			**1.65**	**68.19**			**0.81**	**38.37**

As seen from the table, the discrepancy between the two measurements (at offshore and Uran) was as high as 68 *per cent* on an average for HUT pipeline (ranging between 36 to 119 per cent). The differences for MUT pipeline were slightly lower at an average of 38 *per cent* (ranging between 9 to 61 per cent).

Audit also noticed that there were problems in the functioning of Auto Samplers at both Mumbai High and Neelam Heera offshore Assets. The Mumbai High Asset (in 2012) cited frequent malfunctioning of Auto Samplers. Auto Sampler in Neelam platform did not function from September 2014 to October 2014 while the Auto Sampler in Heera platform was non-functional from November 2014 to January 2015. In the absence of Auto Sampler, the Asset resorts to manual sampling as the Company does not have a standby philosophy for Auto Samplers (unlike Turbine Meters). The consistent differences between the water cut measured at both ends of the closed pipeline point to problems in the functioning of the Auto Sampler.

Management in reply (January 2016) stated the following:

(i) The fields are ageing ones and water cut in the well fluid has increased considerably with present average water cut being more than 70 *per cent*. The partially stabilised crude contains water in emulsion and the average residence time may not be sufficient to completely break the oil-water emulsion, reducing water content to refinery standards before dispatch from offshore. During transportation of crude oil from offshore platform to Uran, crude oil gets high residence time in the pipeline because of its large volume (200 KM pipeline) and consequent large reaction time for emulsion to break and free water to segregate in the pipeline. Hence there is compositional difference in the form of pure oil-free water at receiving end at Uran when compared to offshore end.

(ii) The Auto Sampler, though the best way of collecting representative samples, has some limitations, especially in cases where there is a sharp variation in the fluid composition on account of plant/ processing disturbance.

(iii) In spite of having the most advanced technology for capturing representative sample both at offshore and Uran end for determination of water cut, the differences in water cut have arisen due to inevitable technical reasons.

Ministry further added (April 2016) that SOP on metering and measurementof crude oil have been prepared and issued by all offshore assets.

The reply of the Management needs to be viewed in the following context:

(i) The discrepancy in water cut recorded at offshore and Uran, had been noticed earlier when the Company had appointed a consultant, M/s IHRDC in 2003 to study these differences. The external consultant (M/s IHRDC) in its report (October 2003), had concluded that "*if representative samples are taken both at offshore and onshore locations,* ***their readings must be very close to each other regardless of flow velocities and length of these lines****. The consistent trend of discrepancy points to unrepresentative sampling*".

(ii) The report (of M/s IHRDC) had also concluded that *"**regardless of the type of water (free or emulsified) present, the water measurement at the end of the closed pipeline should match over longer period of time**. The consistent discrepancy between these two measurements makes us question the sampling points and techniques used both at offshore and onshore facilities"*.

(iii) The Mumbai High Asset had pointed to malfunctioning of Auto Sampler at offshore end as contributing to incorrect reporting of water cut in crude dispatched from the Asset.

As admitted by the Management, the present measuring system has limitations/ inaccuracies. The implementation of the Standard Operating Procedures for metering and measurement, assured by Management in reply, would be reviewed in future audits.

C. Non-adherence to calibration schedule of Turbine Meters

The correctness of the measurement is dependent on the accuracy of the measuring equipment. Audit examined the steps taken to ensure accuracy of the Turbine Meters (TMs) installed at offshore platforms (dispatch) and at Uran (receipt). The Neelam Heera and Mumbai High Assets informed that OEM[14] does not prescribe any calibration schedule for TMs but a calibration frequency of two years is followed by the Asset. Uran plant management also informed that the same calibration frequency of two years is adhered to. Management of the Assets further informed that OEM had recommended Turbine Meters to be inspected every three to five years unless measurement anomalies occur and assured Audit that OEM's recommendations were being followed.

Audit observed that while Mumbai High Asset carried out calibration on a regular basis, Neelam Heera Asset has not followed the laid down frequency of two years for calibration of TMs. Out of four TMs installed in the Asset, three had been calibrated after a gap of 4 to 5 years and the balance TM installed in Neelam process complex in November 2008 is yet to be calibrated (January 2016).

Management in reply (January 2016) stated that the execution of Neelam Heera Reconstruction Project led to delay in calibration of meters in Neelam Heera Asset. Ministry also assured (April 2016) that action for calibration of the balance meter has since been initiated.

The assurance of Management/ Ministry will be verified in future audits. It is also stressed that timely calibration of Turbine Meters is necessary for accurate measurement of crude oil.

[14] OEM - Original Equipment Manufacturer