



# **REPORT OF THE COMMITTEE ON THE PRODUCTION SHARING CONTRACT MECHANISM IN PETROLEUM INDUSTRY**



**GOVERNMENT OF INDIA**

**DECEMBER 2012**

## CONTENTS

	<b>Chapter</b>	<b>Page</b>
I	Introduction	5
II	Review of the Existing PSCs and the Proposed New Model	15
III	Managing the Contract Implementation of PSCs	51
IV	Monitoring and Audit of Government Take	69
V	Gas Pricing Mechanism	78
VI	Summary of Recommendations	121



## Preface

The Government of India constituted this committee to look into the Production Sharing Contracts (PSCs) mechanism in petroleum industry.

The exploration and production policy for hydrocarbons is a cornerstone of our energy security, since India has a large and growing demand for energy and substantial hydrocarbon reserves that remain to be explored, appraised and developed. Production Sharing Contracts (PSCs) entered into between the Government and oil companies for the purpose of exploration and production of hydrocarbons constitute the principal means of achieving our overall policy objective of greater self-reliance in this sector.

The committee has aimed at arriving at a mechanism that would lead to greater synergy between the Government and oil companies, thereby enhancing domestic production, simplifying monitoring procedures, and incentivising investments in the exploration and production of hydrocarbons, including from the private sector.

The committee had the benefit of experts drawn from all relevant fields, and is comprised as under:

- (i) Dr C. Rangarajan, Chairman, Economic Advisory Council to the Prime Minister . Chairman
- (ii) Justice Shri Jagannadha Rao . former Judge of the Supreme Court
- (iii) Shri B. K. Chaturvedi . Member, Planning Commission
- (iv) Prof. Ramprasad Sengupta . Distinguished Fellow, India Development Foundation; former Professor of Economics, JNU
- (v) Shri J. M. Mauskar . retired Special Secretary to the Government of India
- (vi) Shri Joeman Thomas . former MD, ONGC Videsh Ltd.
- (vii) Dr K. P. Krishnan, initially Secretary, Economic Advisory Council to the Prime Minister and currently Principal Secretary (Coordination), Government of Karnataka . Convenor

- (viii) Shri Giridhar Aramane, Joint Secretary (Exploration), Ministry of Petroleum & Natural Gas . Secretary

The committee also associated Shri R. N. Choubey, Director General (Hydrocarbons) and Dr Alok Sheel, Secretary, Economic Advisory Council to the Prime Minister with its deliberations, and drew upon their expertise as special invitees to its meetings.

I place on record my sincere thanks to all the committee members and special invitees for their contribution towards finalizing this report.

The committee had the benefit of consultation with the Comptroller and Auditor General of India. It undertook wide-ranging consultations to elicit the views of the public, and stakeholders before arriving at its recommendations.

Last but not the least, I would like to place on record my appreciation to the officers of the Ministry of Petroleum and Natural Gas, the Directorate General of Hydrocarbons and the Economic Advisory Council Secretariat, who enabled the smooth conduct of the proceedings of the committee.

Dr C. Rangarajan  
Chairman, Economic Advisory Council to the  
Prime Minister

# **Chapter I**

## **Introduction**

# **1 Introduction**

## **1.1 The Policy Context**

1.1.1 Availability of affordable energy resources is a key factor for sustainable development of any country. The Exploration and Production (E&P) Policy for hydrocarbons is thus the cornerstone for the energy security of any country. In India, both National Oil Companies (NOCs) and other (private) E&P companies have contributed to E&P in the hydrocarbons sector.

1.1.2 The pattern of energy demand that may be needed to support 9 per cent GDP growth is provisionally estimated and is projected to grow at 6.5 per cent per year between 2010-11 (522.81 Million Metric tonnes of Oil Equivalent, or MMtOE) and 2016-17 (738.07 MMtOE). It is worth noting that dependence on imports for oil is expected to increase from 76.4 per cent in 2010-11 to 80.5 per cent by the end of the Twelfth Plan. According to Planning Commission's Approach to the Twelfth Plan Document, dependence on imports for natural gas is projected to increase from 19 per cent in 2010-11 to 28.4 per cent in 2016-17. In the case of coal, it will increase from 19.8 per cent in 2010-11 to about 22.1 per cent in 2016-17. Hence, it is imperative that production of hydrocarbons in the country be maximised.

1.1.3 Although there has been significant growth in domestic production of oil and gas, India is far from being self-sufficient in this sector. With increasing demand for oil and gas, foreign exchange constraints, and the massive requirement of resources for expeditiously exploring and developing vast on-land and offshore territories, the Government of India designed the New Exploration and Licensing Policy (NELP) in 1999, thereby opening the sector to all players, including foreign companies, with the aim of attracting private investment and infusing technology from around the world.

## **1.2 Exploration Prospectivity of Indian Sedimentary Basins**

1.2.1 The sedimentary basins of India, both on-land and offshore up to the 200-metre isobath, have an area of about 1.79 million sq. km. So far, 26 basins have been recognized. These have been divided into four categories, based on their

degree of prospectivity as presently known. In deep waters, beyond the 200-metre isobath, the sedimentary area has been estimated to be about 1.35 million sq. km. The total, thus, works out as 3.14 million sq. km. Of these, the unexplored area is 12%, the poorly explored area is 22%, the moderately- to well-explored area is 22%, and the area in which exploration has been initiated is 44%. Concerted efforts are continuously being made by the Government to further reduce the unexplored area by carrying out surveys and offering surveyed areas in NELP rounds. The four recognised categories of basins are (i) Category I basins, with established commercial production, (ii) Category II basins, with known accumulation of hydrocarbons but no commercial production as yet, (iii) Category III basins, with indications of hydrocarbon shows that are considered geologically prospective, and (iv) Category IV basins, with uncertain potential which may be prospective by analogy with similar basins in the world. This categorisation will change with the results of further exploration.

1.2.2 Following the initiation of extensive exploration in the late 1950s, a resource estimation exercise was carried out by ONGC for 15 sedimentary basins in the 1990s, which has now been adopted by the Directorate General of Hydrocarbons with a few minor modifications. Out of the total 26 basins in India, 15 sedimentary basins are estimated to hold a hydrocarbon resource potential of 28 billion tonnes (Oil plus Oil Equivalent Gas, or O+OEG), against which in-place volumes of the order of 9.8 billion tonnes (O+OEG) have been established by ONGC, OIL and other (private) operators. The conversion factor, thus, is of the order of 35%.

1.2.3 An analysis of the response to Notice Inviting Offers under NELP rounds VI to IX in Category-I basins reveals that the prospectivity perception is indeed high among operators, which is evident from the fact that competition was very high for all the blocks, with companies bidding with very high work programme commitments and offering a very high Government take. It is also a fact that multinational companies are operating and acquiring deep-water acreage in the Western Offshore, notwithstanding a generally lower prospectivity perception.

1.2.4 Exploration in Category-I basins (basins with commercial production) is normally intensive as it leads to growth of the field and enhanced production. The capital and operational expenditure requirements are, in general, less than for basins falling in other categories, owing to pre-existing infrastructure. However, with increasing exploration/drilling density and the discovery of larger fields, the field size of new discoveries in the already discovered plays tends to



be small. The E&P policy needs to allow development of small/marginal fields in Category-I basins.

1.2.5 Exploration in frontier basins is, in general, a difficult task due to complex geology, hostile logistics and very poor E&P infrastructure. Despite the fact that many blocks in frontier basins have been awarded under NELP, frontier basins have remained poorly explored, with the total area of Category III & IV basins remaining is about 0.91 million sq. km. The prospectivity perception of frontier basins too gets enhanced if one considers the headway made in the Vindhyan Basin by ONGC through a discovery at Nohta-1 & 2.

### **1.3 Investment Risk in the E&P Sector**

1.3.1 Hydrocarbons can be found miles away from the place where they were generated and from where they travelled through tortuous migratory paths before getting accumulated in a trap where they have remained preserved till date. The risk of dry holes is, thus, the fundamental operative risk in petroleum exploration. The industry has come a long way since the days of anticlinal theory to development of sophisticated models for exploration of stratigraphic traps. This has been largely facilitated by an explosion in technology in the fields of seismic data acquisition, processing and interpretation for better imaging of the subsurface. Despite these developments, a 25-30% rate of commercial success is considered good. The cost of a well could range between less than US\$ 2 million in the case of an on-land well in an area where infrastructure and services are readily available, to more than US\$ 150 million for an ultra-deep-water well.

1.3.2 As Operators are required to risk investing huge amounts of money under conditions of uncertainty, they need to be adequately compensated so that they are encouraged to invest in exploration. At the same time, Government's interests as the owner need to be protected. Therefore, the E&P policy and contracts need to provide an equitable return on investment to Operators while protecting Government's interests.

### **1.4 Production Sharing Contracts**

1.4.1 A Production Sharing Contract (PSC) is a contractual regime entered into by the Government and the Contractor for the purpose of E&P of hydrocarbon resources, namely, crude oil and natural gas. The Petroleum and Natural Gas

Rules, 1959 provide for an agreement between the Government and the licensee or lessee, to lay down the terms and conditions with respect to the licence or lease. These terms and conditions are stipulated as articles of the PSC. A note on the History of the Search for Oil in India, right up to the emergence of PSCs under the New Exploration and Licensing Policy (NELP), is at Annexure-B.

1.4.2 PSCs are now the dominant mode of hydrocarbon administration in the country. These contracts are basically regulatory contracts by virtue of derivation from article 297 of the Constitution of India. Article 297 provides that petroleum in its natural state in the territorial waters and the continental shelf of India is vested in the Union of India. The Oil Fields (Regulation and Development) Act, 1948 and the Petroleum and Natural Gas Rules, 1959 made thereunder make provisions for the regulation of petroleum operations.

1.4.3 The fiscal regime in existing PSCs for conventional oil and gas is based on the Contractor doing petroleum operations at his risk and cost, and, sharing of profit petroleum with the Government after cost recovery, the calculation of which is based on a Pre-Tax Investment Multiple (PTIM). For the purpose of implementation of contractual provisions in the PSC regime, a management structure exists in the form of a Management Committee (MC). A similar management structure, called a Steering Committee, is envisaged for blocks offered under the Coal-Bed Methane (CBM) Policy. Under such a contract, the risk of exploration is borne entirely by the Contractor, and only in case of a commercial discovery, the Contractor is allowed to set off the cost incurred on exploration, and subsequently on development and production, against revenues earned in the operation. Balance revenues are shared between the Contractor and the Government in the proportion agreed to in the PSC. Royalty and income tax are separately payable.

1.4.4 India adopted the PSC model in order to invite both foreign and Indian companies and to attract investment and latest technology in the upstream hydrocarbons sector. The PSC model was considered to be more progressive than the nomination regime as MCs constituted under it offered a suitable forum for regular interaction between the Government and Contractors. Contractors were given representation on MCs, with each company constituting the Contractor being represented through a member on the MC. In addition, there

are two Government nominees on the MC. Thus, the PSC model was made operational through a system of joint management. Commonwealth Secretariat, UK was engaged as the consultant to draft the Indian PSC in the light of international developments. The model PSC developed was used in nine rounds of NELP with several modifications made from time to time.

1.4.5 Government's share of profit petroleum forms part of Government receipts and is credited under a separate accounting head operated for profit petroleum. However, cost recovery made by the contractor is deemed to be expenditure incurred on exploration. As per canons of financial propriety, all expenses from Government accounts should be made with the utmost care and while observing financial prudence. In case of expenses under the PSC, the Contractor is allowed complete recovery of cost petroleum, which reduces the share of Government in profit petroleum. Thus, there is a need for careful monitoring of expenses incurred.

1.4.6 Some of the key issues that have arisen in respect of existing PSCs are as follows:

- (a) The existing formula on sharing profit petroleum is dependent on cost recovery by the Contractor. This parameter determines the Government's and Contractor's shares of profit petroleum. However, this system encourages the Contractor to inflate costs, to the detriment of Government's share in profit petroleum.
- (b) Decision-making by representatives of the Government and the Contractor through the MC is done, preferably, on the basis of unanimity and, failing that, through majority voting. In practice, however, no decision can be achieved in the absence of unanimity among parties to the contract. The majority voting provision for a decision in the MC is superficial as only proposals approved by the Operating Committee (on which Government is not represented) can be brought for consideration of the MC. Contractors tend to perceive Government's administrative efforts, taken with the larger public interest in mind, as micromanagement of field operations through the MC. MCs often find themselves in a stalemate over consideration of such issues, especially financial issues related to budgets. Many of these issues remain unresolved for long, thereby

adversely impacting the achievement of the basic objectives of hydrocarbon exploration and development.

- (c) Other areas of concern for the Government in a PSC relate to:
- i. adequacy of investments made, to ensure stipulated levels of production;
  - ii. ensuring correct accounting and calculation of Government's take; and
  - iii. observance of procurement procedures laid down in the PSC.

## **1.5 Committee on the PSC Mechanism in Petroleum Industry**

1.5.1 The Government of India constituted this committee under the chairpersonship of Dr C. Rangarajan, Chairman, Economic Advisory Council to the Prime Minister, to look into the PSC mechanism in petroleum industry, so as to enhance production of oil and gas and the Government's share, while minimising procedures for monitoring the expenditure of producers.

1.5.2 The composition of the committee is as follows:

- (i) Dr. C. Rangarajan, Chairman, Economic Advisory Council to the Prime Minister . Chairman
- (ii) Justice Shri Jagannadha Rao . former Judge of the Supreme Court
- (iii) Shri B. K. Chaturvedi . Member, Planning Commission
- (iv) Prof. Ramprasad Sengupta . Distinguished Fellow, India Development Foundation; former Professor of Economics, JNU
- (v) Shri J. M. Mauskar . retired Special Secretary to the Government of India
- (vi) Shri Joeman Thomas . former MD, ONGC Videsh Ltd.
- (vii) Dr K. P. Krishnan (initially Secretary, Economic Advisory Council to the Prime Minister and currently Principal Secretary (Coordination), Government of Karnataka) . Convenor
- (viii) Shri Giridhar Aramane, Joint Secretary (Exploration), Ministry of Petroleum & Natural Gas . Secretary

1.5.3 The committee also associated Shri R. N. Choubey, Director General (Hydrocarbons) and Dr Alok Sheel, Secretary, Economic Advisory Council to the Prime Minister with its deliberations, and drew upon their expertise as special invitees.

1.5.4 The terms of reference of the committee were as follows:

- (i) Review of the existing PSCs, including in respect of the current profit-sharing mechanism with the Pre-Tax Investment Multiple (PTIM) as the base parameter;
- (ii) Exploring various contract models with a view to minimise the monitoring of expenditure of the contractor without compromising, firstly, on the hydrocarbons output across time and, secondly, on the Government's take;
- (iii) A suitable mechanism for managing the contract implementation of PSCs, which is being handled at present by the representation of Regulator/Government nominee appointed to the Managing Committee;
- (iv) Suitable governmental mechanisms to monitor and to audit Government of India's share of profit petroleum;
- (v) Structure and elements of the guidelines for determining the basis or formula for the price of domestically produced gas, and for monitoring actual price fixation;
- (vi) Any other issues relating to PSCs.

1.5.5 The committee deliberated on its Terms of Reference (ToRs) and concluded that a careful reading of the ToRs indicates that its recommendations in respect of ToRs (i) and (ii) would apply only to PSCs entered into in future, while its recommendations in respect of ToRs (iii), (iv) and (v) would also be applicable to existing PSCs. However, insofar as ToR (v) is concerned, the committee recommended that the pricing formula proposed by it would only apply prospectively and is not proposed for application to gas prices already approved.

1.5.6 In making its recommendations, the main objectives that the committee kept in view were the following:

- (i) Addressing the energy security demands of the country by enhancing domestic production, with the aim of ensuring affordable supply (in a cost-effective sense) of hydrocarbons;
- (ii) Developing local expertise and supporting the NOCs in their mission of building national capacity in exploration and production;
- (iii) Encouraging exploration in frontier basins and areas;
- (iv) Allowing development of marginal/small fields which are part of producing basins;
- (v) Providing an environment conducive for investments in the E&P sector by providing incentives to investors, including from the private sector, and a reasonable return on investment;
- (vi) Reducing monitoring procedures: monitoring could be limited to technical and fiscal aspects, which would reduce approval delays.

1.5.7 The committee met on 18<sup>th</sup> June, 13<sup>th</sup> July, 13<sup>th</sup> & 14<sup>th</sup> August, 17<sup>th</sup> September, 19<sup>th</sup> October and 9<sup>th</sup> November 2012, and deliberated on all aspects relevant to its terms of reference. It consulted the Comptroller and Auditor General of India (CAG) in respect of ToR (iv). It invited comments from the public. Representatives of the following E&P companies and industry associations were also offered an opportunity to present their views to the committee:

(a) On 13<sup>th</sup> August 2012

- (i) Federation of Indian Chambers of Commerce and Industry (FICCI)
- (ii) Oil and Natural Gas Corporation Limited (ONGC)
- (iii) Association of Oil and Gas Operators (AOGO)
- (iv) Confederation of Indian Industry (CII)
- (v) British Petroleum (BP)

(b) On 14<sup>th</sup> August 2012

- (i) Reliance Industries Limited (RIL)
- (ii) BG India (BG)
- (iii) Cairn India Limited (CIL)
- (iv) Great Eastern Energy Corporation Ltd. (GEECL)

- (v) Hindustan Oil Exploration Company (HOEC)
- (vi) Joshi Technologies International Inc. (JTI)
- (vii) Assam Oil Company (AOC)

(c) On 19<sup>th</sup> October 2012

- (i) Reliance Power (RP)
- (ii) Reliance Industries Limited (RIL)
- (iii) British Petroleum (BP)

Presenting companies which had not given written submissions were requested to make written submissions.

1.5.8 The committee took note of the views expressed and the submissions made before it and arrived at its recommendations after due deliberation. The issues related to and the recommendations on ToRs (i) and (ii), which concern the fiscal package of the PSC regime, are detailed in Chapter II. Those related to ToR (iii), which concerns the mechanism for contract implementation, are in Chapter III. Issues and recommendations related to ToR (iv), which concerns audit, are in Chapter IV. Issues and recommendations relating to ToR (v), on gas pricing, are in Chapter V. A summary of the recommendations forms Chapter VI.

## **Chapter II**

# **Review of the Existing PSCs and the Proposed New Model (ToRs i & ii)**



## **2** Existing PSC System and Constraints

### **2.1 Existing Production Sharing Contracts**

2.1.1 The existing PSC system under NELP was originally designed as the framework for offering exploration blocks alongside steps then being taken for progressive de-regulating the hydrocarbon sector.

2.1.2 Some of the main elements of incentives incorporated in the design of the PSC under NELP were-

- (i) the removal of any carried interest of the State, like in Pre-NELP bidding rounds; freedom to Contractors to market crude oil and natural gas in the domestic market;
- (ii) abolition of the cess levied earlier on the production of crude oil; reduction of royalty rates;
- (iii) exemption from payment of import duties on goods imported for petroleum operations; and
- (iv) seven-year tax holiday from the date of commencement of commercial production, etc.

Another major fiscal incentive was in form of the Fiscal Model incorporated in the PSC.

2.1.3 The Fiscal Model in the existing PSC comprises two main elements, both of which are biddable: (i) cost recovery and (ii) sharing of profit petroleum, based on the Pre-Tax Investment Multiple (PTIM). Cost recovery is the independent variable and determines the profit petroleum, which is the dependent variable. The shares of the Operator and the Government in profit petroleum in a particular year are calculated on the basis of PTIM actually achieved by the Contractor at the end of the preceding year.

### **2.2 Cost Recovery**

2.2.1 The Contractor is entitled to deduct a biddable percentage (up to a maximum of 100%) of the admissible contract costs, from the total value of

petroleum produced and saved from the Contract Area. The portion of Contract Cost deducted in a year is termed as Cost Petroleum

2.2.2 Any un-recovered portion of Contract Costs is carried forward to succeeding years if during any year, cost petroleum is not sufficient to enable the Contractor to recover in full Contract Costs, due for recovery in that year, then:

- a) firstly, royalty payments are recovered;
- b) production costs are recovered next;
- c) exploration costs are recovered next;
- d) finally, development costs are recovered.

### **2.3 Sharing of Profit Petroleum on the basis of the Pre-Tax Investment Multiple (PTIM)**

2.3.1 The revenue remaining after cost recovery is called profit petroleum. In any one fiscal year, profit petroleum is shared between the Contractor and the Government in different proportions, depending on the Contractor's Pre-Tax Investment Multiple (PTIM), or the Investment Multiple (IM), in the previous year.

2.3.2 The Investment Multiple ratio for the Contractor is calculated at the end of any year by dividing the summation of annual Net Cash Incomes (accumulated, without interest, up to and including that year, starting from the year in which production costs were first incurred, or production first arose) by the summation of annual investments (accumulated, without interest, up to and including that year in which exploration and development costs were first incurred).

2.3.3 Net Cash Income equals Contractor's revenue (cost petroleum plus Contractor's share in profit petroleum) less Contractor's production costs and royalty payments. Investment equals Contractor's exploration costs plus development costs.

2.3.4 The IM ratio in a given year determines the split of profit petroleum between the Contractor and the Government in the succeeding year. IM ratio slabs, on the basis of which profit petroleum split is decided, are stipulated in the PSC, and are based on the bid made by the Contractor during the process of award of the block. Usually, higher the IM ratio, higher is the Government share.

Contractors revenue consists of revenue from cost petroleum, plus a share of profit petroleum.

2.3.5 On the issue of possible manipulation of the Investment Multiple (IM) the CAG, in its report ~~Performance~~ Audit of Hydrocarbon PSCs+ has brought out a critique on format of PSC which is quoted below:

**Conclusions and General Recommendations of CAG:**

Structure of PSC: ... In practice, however, the private contractors have inadequate incentives to reduce capital expenditure – and substantial incentive to increase capital expenditure or “front-end” capital expenditure, so as to retain the IM in the lower slabs or to delay movement to the higher slabs.

The structure of the IM-based profit sharing formula (especially when there is a huge jump in GOI’s profit share from 28 per cent to 85 per cent on an IM slab of 2.5 or more) is such that in certain scenarios, an increase in capital expenditure, up to a point, could conceivably result in an increase in the contractor’s share of profit petroleum, despite a reduction in the total profit petroleum as well as GOI’s share of profit petroleum. Further, “front-ending” of capital expenditure (i.e. skewed towards the initial phases) decreases the IM, and postpones the movement to higher IM slabs; this results in a reduction in GOI share on a discounted cash flow basis, since the slabs involving higher GOI share come later, rather than earlier.

Possible incentives for opportunistic manipulation existed particularly with the pre-2007 (up to NELP-VI) stair-step structured sliding scale investment multiple (IM)-based systems as contractors approached various IM thresholds. However, with the post-2007 (NELP-VII onwards) design, i.e., the percentage share bid by the contractor for IM < 1.5 and > 3.5 is extrapolated linearly to work out the intermediate IM tranches, this potential problem has been addressed to some extent. Given the vexatious issue of transfer pricing, it is very difficult to avoid such disputes altogether.

“Front-ending” of capital expenditure (i.e. skewing towards the initial phases) decreases the IM, and postpones the movement to higher IM slabs, while resulting in a reduction in the GOI share on a discounted cash flow basis.

While it is possible that the Operator may increase expenditure in the initial years of production so as to postpone approaching a higher IM tranche to reduce Government’s share, over the full period of the contract the Operator will not be able to avoid the IM threshold, as long as overall costs for the production are correctly ascertained. Apart from the cost issue the pricing of natural gas may also influence Operators decisions and thus, indirectly, affects IM as the Operator will be incentivized to produce faster when gas prices are high and vice versa. Nevertheless, it may be noted that PTIM is not conceptually flawed. The problem fundamentally is on account of the difficulties faced in arriving at the true cost incurred by the Operator, which has led to some controversy. Issues of transfer pricing by the Operator are at the heart of such disputes. However, this issue relates to existing PSCs, particularly those entered into under earlier PSC rounds in which the IM-based government-take varied discontinuously, creating incentive for cost planning or manipulation. For such old PSCs, Government will need to address the issue as per established procedure and contract provisions for determination of costs.

## **2.4 Constraints during the Exploration Period of the PSC**

2.4.1 The current contractual model provides for a specific exploration period, which stipulates a period of seven or eight contract years, depending on the NELP round and the location of the block . whether on-land, in shallow waters, or in deep waters.

2.4.2 Once discoveries have been made during the exploration period, appraised in accordance with the terms and conditions of the contract, and declared commercial (i.e. declaration of commerciality has been done), the discoveries undergo development. However, it may be noted that any further hydrocarbon exploration during the development phase of other discoveries or commercial production loads exploration costs on existing discoveries.

2.4.3 The commercial interests of Gol in existing discoveries may be compromised if exploration beyond the exploration period is allowed, due to the fact that PTIM may get depressed in scenarios like the new discovery being too marginal or failing to produce.

2.4.4 Thus, the existing cost-recovery based model is a major bottleneck in furtherance of exploration in the existing Blocks/Fields, once the Exploration Period is completed.

### **3** Need for Review of the PSC

3.1 India has experience of operating various E&P contractual and fiscal regimes since the commencement of hydrocarbon exploration in the country. As the perception of hydrocarbon prospectivity in Indian hydrocarbon basins has evolved over the years, the tenets of fiscal and contractual models driving exploration and exploitation of hydrocarbons have also changed. While all the nomination acreages operated by National Oil Companies (NOCs) are under a Royalty . Tax regime, the Pre-NELP (New Exploration Licensing Policy), Discovered Field and NELP acreage is driven by a PSC regime. The PSC regime, which is now the dominant mode of hydrocarbon administration in the country, embodies a fiscal model having as its basic elements cost recovery and sharing of profit petroleum. The Government and Contractor's share of profit petroleum are linked to the Pre Tax Investment Multiple (PTIM) achieved by the Contractor in undertaking petroleum operations in the Block or Oilfield. The Blocks offered under the Coal-Bed Methane (CBM) Policy incorporate a Production Level Payment (PLP) system in the fiscal model. In this model, apart from the royalty, the Contractor is required to make *ad valorem* Production Level Payments (PLP) on a sliding-scale based on incremental production, without any reference to cost petroleum.

3.2 Governments all over the world have devised numerous frameworks for extracting economic rents from the petroleum sector. India adopted the PSC model while formulating the E&P policy during the 1980s and the early 1990s, in order to attract investment and latest technology from foreign and Indian companies in the upstream hydrocarbon sector. The PSC model was considered to be more progressive than the Royalty . Tax regime as it introduced the biddable elements in the fiscal model and also reduced the royalty rates in comparison to the nomination regime. It also introduced the fiscal element of profit petroleum for the Government as an element of economic rent recovery. The PSC model was to be made operational through a system of joint management prevalent in this model. To evolve the terms and conditions to be stipulated in the PSC, Commonwealth Secretariat, UK was engaged as the consultant to draft the Indian PSC in the light of international developments. The

model PSC developed was used in eight rounds of Pre-NELP, nine rounds of NELP and the Discovered Field rounds, with several modifications made from time to time.

3.3 However, as PSCs have progressed from the exploration stage to the development and production stage through successive NELP rounds, certain constraints have been observed in the working of the PSC model by both the Government and Contractors. The extant fiscal model, with primary focus on recovery of upstream costs, has been found to be a major constraint in expediting exploratory work and is also lacking in incentive to keep costs down.

3.4 This constraint is now increasingly overshadowing the basic Government objectives of energy security through expeditious development of hydrocarbon resources available in the country while simultaneously conserving and promoting their efficient use. The country's need for hydrocarbons is accentuated when one considers the scarce availability of this precious natural resource in the country and the huge foreign exchange outgo on import of petroleum and petroleum products. The Government, while remaining committed to guard the natural wealth available within our frontiers, needs to promote judicious development of oilfields.

3.5 Contractors at times perceive Government's efforts to protect its commercial and technical interests as micromanagement of oil & gas field operations, either through Management Committees (MC) or otherwise. Industry associations and Contractors have expressed industry's sensitivity towards maintenance of the sanctity of existing contracts. However, most of them are open to the options selected for future contracts.

3.6 The MC, with its composition of two Government nominees and one representative each from the companies constituting the Contractor, often find themselves tied in knots over consideration of fiscal elements of cost recovery. With many crucial cost-related functions vested in the MC, Government nominees on the MC would be under an obligation to examine and monitor budgets, procurement, benchmarking of costs, allocation of costs, accounts etc. by reviewing and approving these in the MC. As cost aspects are internal to a company, their monitoring and auditing generates resistance from the Contractors and requires protracted correspondence between the Government

and the Contractor. As a result, many issues remain unsettled for long, thereby adversely impacting the achievement of the basic objectives of hydrocarbon exploration and exploitation.

3.7 To understand and address the constraints, this committee to review the production-sharing mechanism and PSCs in hydrocarbon exploration was constituted under the chairmanship of Dr C. Rangarajan, Chairman, Economic Advisory Council to the Prime Minister, and with other relevant experts as members. The committee deliberated at length upon the merits and demerits of the existing contractual and fiscal model in the light of the experience gathered through operation of nine rounds of the New Exploration Licensing Policy (NELP). The committee also explored the efficacy of other models of contracts in the context of India's geological situation. The committee also engaged with various stakeholders to arrive at a suitable alternative mechanism / model for the future.



## **4 Stakeholder Views**

### **4.1 Concerns of the Operators Regarding the Current Upstream Scenario**

4.1.1 Several Operators and Operatorsq associations made detailed presentations on their views with regard to the upstream hydrocarbon sector in India. They presented their views to the committee on 13<sup>th</sup> and 14<sup>th</sup> August. Views of various stakeholders have been grouped and are presented in succeeding paragraphs.

### **4.2 The Existing PSC System and the Fiscal Model**

4.2.1 The Federation of Indian Chambers of Commerce & Industry (FICCI) recommended no change in the existing PSCs and stated that issues raised with regard to PTIM constitute a technical point only. It stated that review of the existing PSCs would only be relevant for future contracts. It further recommended that future contracts may be on the basis of a royalty - tax regime. On the fiscal regime, it highlighted that this should be simple to administer, stable throughout the asset lifecycle and aligned to the block and business interests. The objectives should be to promote E&P investments, attract private and foreign risk capital, and Government's stake should only be consequential.

4.2.2 On the issues of full cost-recovery, the Association of Oil and Gas Operators (AOGO) stated that related CAG issues and delays are key challenges in approvals. It submitted that all countries are not the same. Countries endowed with good geology maximise government revenues, with limited focus on exploration and greater focus on exploitation. Nationalisation and reservation for NOCs are poor fiscal terms for investors. On the other hand, countries with poor geology maximise exploration and production. In such cases, the focus is on energy security and attracting investors. Such countries should devise attractive fiscal terms. The Association recommended that the sanctity of contracts be maintained at any cost.

4.2.3 BG India stated that India has a low exploration success rate, and that interest is declining. There are very few players with a proven track record, and very little churning of exploration acreage. There is uncertainty and delay around statutory clearances and these must be reviewed for change. BG stated that the Indian market is attractive but India has a slow and arduous operating environment. On the essentials of the fiscal structure, BG stated that there should be clarity on what the national priorities are: whether rent is the priority or reserves and production are. There must be an atmosphere of trust and a long-term and sustainable relationship with the host government.

4.2.4 British Petroleum stated that the sanctity of existing PSCs is critical to compete for scarce capital and capability, and that the existing 228 PSCs are ~~not broke~~. Contracts are sacrosanct and Contractors base their long-term operations, capital structures and investment processes around predictable fiscal systems. Changing the existing contracts will drive investors away. Current contracts were awarded on the basis of technical/financial pre-qualification and a competitive and transparent bidding process. Any change in existing contracts will destroy GoI credibility, drive away investors, open up multiple disputes, invite further audit scrutiny, and likely bring E&P activity to a grinding halt. It further stated that there are no incentives for Contractors to inflate costs.

4.2.5 Cairn Energy stated that there is a need to strengthen the institutional framework irrespective of the fiscal regime. Cairn Energy was neutral with regard to the choice of regime, going forward. However, it stated that migration of existing contracts could be a considerable challenge.

4.2.6 Hindustan Oil Exploration Company observed that profit-sharing linked with PTIM may be affected on account of front-end capex. Therefore, a mechanism for monitoring and benchmarking costs is required. The mechanism may not seem to encourage investment in re-development/secondary/tertiary recoveries to protect profit-sharing in the short term. However, over the long term, such re-development investment would tend to yield increased profit-sharing, on account of enhanced production over the full life of the field.

4.2.7 ONGC stated that profit-sharing through the Investment Multiple involves monitoring of Contractor's investments and income. Cost recovery involves monitoring and auditing of annual budgets, auditing of accounts, etc. Thus, there

is uncertainty with regard to the time required to obtain regulatory approvals, and the interpretation of PSC provisions is restrictive. ONGC proposed doing away with the cost-recovery mechanism and proposed a production and price linked regime. It opined that this will enable a share in profit petroleum to the Government from day one of production and will also address the issue of over-assessment of costs by Operators. It stated that the new model will enable concentration on monitoring of technical aspects and address the issue of windfall profits accruing to the Contractor in case of a price surge.

4.2.8 Reliance Industries Limited (RIL) said that NELP sought to maximise exploration and production. RIL also felt that the goal-post has moved from maximisation of exploration and production to revenue maximisation. It stated that the Government has a misplaced focus on cost-control as the sole aim, and that this has led to non-acceptance of commerciality of discoveries, preventing the contractor from drilling exploration wells, and to a reading of the PSC as a restrictive rather than an enabling framework. Regulatory delays have led to non-approval of work programme and budget, non-approval of annual accounts and profit petroleum for years, and indefinite stalling of MC procedures and resolutions.

### **4.3 PSC Administration**

4.3.1 FICCI recommended reducing the incidence of governmental approvals on operational issues.

4.3.2 AOGO stated that in running the hydrocarbon administration, non-PSC issues are slowing down PSC decision-making.

4.3.3 BP placed the focus in PSC administration on increasing activity . safely and reliably. It recommended autonomy to and accountability of the Contractor, without loss of control by the Government.

4.3.4 RIL stated that PSC only authorises the Operator to conduct petroleum operations on behalf of the Contractor and neither the MC nor the Government has this authority. If Government had the expertise to conduct petroleum operations there would have been no need to invite participation from private oil and gas operators.

#### **4.4 Alternate PSC Models**

4.4.1 For future contracts, FICCI recommended moving to a concessionary regime based on a pure Royalty . Tax System, with no production-sharing. FICCI also stated that the industry is more sensitive to the stability and sanctity of existing contracts and, therefore, it will live with any of the options selected for future contracts.

4.4.2 BP stated that given the level of E&P maturity in India, PSCs are likely to be the best path forward.

4.4.3 RIL opined that the PSC regime is best suited to acreage with inadequate data and low prospectivity.

4.4.4 ONGC suggested a production and price linked regime which will do away with the cost-recovery mechanism and reduce the effort and the time involved in examination and monitoring. This proposed alternate model will also address the issue of accrual of windfall profits to the Contractor in case of a hydrocarbon price surge or a geological surprise on account of a large hydrocarbon find.

#### **4.5 Management Committee (MC)**

4.5.1 AOGO opined that the MC should focus on taking decisions of a more strategic nature and on maximising activities with optimal investments. MC approvals should only be required for the Field Development Plans (FDP) and non-exploration related work programme and budget before the FDP stage. It also suggested that MC's role should be an advisory one and not an approving one.

4.5.2 FICCI recommended holding MC meetings in a timely manner and reviewing/approving the proposals within timelines provided in the PSC.

#### **4.6 Audit**

4.6.1 FICCI stated that the scope of audit should be limited to financial audit and not performance audit.

4.6.2 RIL stated that the purpose of audit is not to question technical and operational decisions of the Contractor and the MC. The audit uses hindsight to question operational decisions and examine individual contracts in a fragmented and isolated manner, ignoring the overall project perspective.

## 5

# Description of the Proposed Contractual System

5.1 The objectives of the fiscal regime have to be promotion of investment by offering a reasonable and hassle-free regime, and achieving this without sacrificing Government's interest as the owner. In assessing the existing system and arriving at a new fiscal regime, the committee sought to achieve both these objectives in a balanced manner.

5.2 The problems with the existing PSC system, highlighted in Part 3 of this Chapter, and the concerns expressed by the industry and other stakeholders, as indicated in Part 4, are inherent to the system. Therefore, need is felt for a new system which would not have these pitfalls.

5.3 A new contractual system is proposed to overcome the logjam created by the existing model based on the Pre-Tax Investment Multiple (PTIM) methodology and the cost-recovery mechanism. The basic nature of the present model is its primary focus on upstream costs incurred . on exploration, development and production. Government has to get involved in the nitty-gritty of day-to-day business operations of the Contractor through examination and monitoring of budgets, procurement, costs, allocation of costs, accounts etc., by reviewing and approving these in the Management Committees (MC). There are many crucial cost-related functions vested in the MC which require timely approvals. As cost aspects are internal to a company, their monitoring and auditing requires protracted correspondence between the Government and the Contractor, with many issues remaining unsettled for long. The new regime proposed will help overcome the uncertainty involved in various kinds of MC approvals.

5.4 The design of the new regime needs to provide a simpler and transparent hydrocarbon administration with easy-to-monitor parameters of production and price, rather than the cost parameter which is internal to the functioning of the companies. This should result in approvals sought by the Contractors from the MC and the Government being accorded speedily.

5.5 An easy-to-administer hydrocarbon regime will also help the Government focus on technical and real productivity related aspects of the upstream hydrocarbon sector. There are many important technical issues like Reservoir Management, Enhancement of the Recovery Factors (RF), Health, Safety and Environment (HSE) Management, and Enhanced and Improved Oil Recovery (EOR/IOR) Schemes, which vie for the hydrocarbon administrator's attention. These issues take a back-seat due to the primary focus being on cost and investment in the current model.

5.6 One of the main objectives of Governments around the world in designing the fiscal system for the upstream hydrocarbon sector is to capture economic rent. The purpose of any fiscal restructuring and taxation is to capture economic rent, while giving the industry a reasonable share of profit or 'take+'. In the existing PSC system, with its liberal cost recovery provisions, the Government take comes at a relatively later stage of production, with the Government thus bearing a major proportion of 'cost risks' during the project lifecycle. In many cases, with a 'creative' use of costs and investments by the Contractor, the profit petroleum and associated economic rent to the Government may get delayed. However, in the new model, this may get addressed since revenue-sharing of hydrocarbons would commence with the onset of production in the field.

5.7 Another important aspect of the new model is the sharing with the Government of economic rents arising in the form of windfall profits, in the event of a hydrocarbon price surge or a geological surprise by way of a huge find.

5.8 There is said to be some relationship between the fiscal regime and prospectivity. However, the perception of prospectivity undergoes a change over time.

## **5.9 Prospectivity versus Fiscal Regime:**

5.9.1 A review of the history of exploration in any country / new basin / new play would demonstrate that new players flock a particular province once the geological risk is removed through efforts made by initial risk-takers through the latter's endeavour to search and establish oil and gas reserves. Such initial geological risks are normally borne by the host country through NOCs. As more

players / Operators enter the exploration arena, many factors, most importantly the attractiveness of the fiscal systems and the prospectivity perception about the province, become moot points for discussion.

5.9.2 Several criteria like (i) prospectivity, (ii) the costs that would be incurred for exploration and development, (iii) the amount of time it would take to move from exploration to production, (iv) the attractiveness of fiscal systems commensurate with prospectivity, and (v) strong rules of law and efficient regulations for energy development, are considered critical for an investment-friendly atmosphere.

5.9.3 It is a general perception that if prospectivity is considered to be very good then the fiscal systems would be pro-Government and *vice versa*. *In practice, governments are prone to underestimating the remaining potential of a province till such time as new geological concepts get tested and confirmed subsequently.* This has been a feature of the North Sea, the Gulf of Mexico, and many other hydrocarbon provinces. In this context it becomes pertinent to dwell upon the complex paradigm of prospectivity versus fiscal regimes in the Indian scenario in succeeding paragraphs.

5.9.4 It is a known fact that several multinationals had written off the Indian offshore sector in the late sixties and early seventies as having very poor prospectivity. With the determined efforts of ONGC and the Government, Bombay High was discovered in the year 1974. This was followed by many big discoveries like Panna, Mukta, Tapti, Neelam Heera, D-1 etc., which have totally changed the perception about the Western Offshore shelf.

5.9.5 Following the initiation of extensive exploration in the late 1950s, a resource-estimation exercise was carried out by ONGC in the 1990s for 15 sedimentary basins, which has now been adopted by DGH with a few minor modifications. Out of a total of 26 sedimentary basins, 15 Indian sedimentary basins are estimated to hold a hydrocarbon resource potential of 28 billion tonnes (O+OEG), against which in-place volumes of the order of 9.8 billion tonnes (O+OEG) have been established by ONGC, OIL and other (private) operators. The conversion factor, thus, is of the order of 35% .

5.9.6 The fiscal models of the pre-NELP rounds, wherein the NOCs were to pay the royalty on behalf of the consortium, can be construed as an acknowledgment of the underestimation of the prospectivity of Indian sedimentary basins.



5.9.7 An analysis of the response to the Notice Inviting Offers under NELP rounds VI-IX in Category-I basins reveals that the prospectivity perception is indeed high among various operators, which is evident from the fact that competition was very high for all the blocks, with companies bidding with very large work programme commitments and offering a high Government take. It is also a fact that multinational companies are operating deep-water acreage in the Western Offshore notwithstanding the generally lower prospectivity perception.

5.9.8 The recent finds by ONGC in the KG and Cauvery On-land Basins (like Malleswaram, Bantumilli South and Periyakudi) have brought new play perceptions to the fore. The discovery in Gujarat Kutch Offshore, Saurashtra Offshore and field growth of the D-1 field through a significant new discovery, D-6 discovery, and the discovery of hydrocarbons by CEIL in Cauvery deep-water have all reinforced the confidence in the prospectivity perception of Indian sedimentary basins.

5.9.9 The United States Geological Survey (USGS) regularly carries out a study for assessing the undiscovered oil and gas resources worldwide. USGS, in the year 2012, has published a study titled 'Assessment of Undiscovered Oil and Gas Resources of the Assam, Bombay, Cauvery, and Krishna Godavari Provinces, South Asia, 2011+'. Using a geology-based assessment methodology, the U.S. Geological Survey estimated volumes of undiscovered, technically recoverable, conventional petroleum resources for the Assam, Bombay, Cauvery and Krishna Godavari Provinces in South Asia. The respective total for these four provinces is 3.534 billion barrels of crude oil, 79.352 trillion cubic feet of natural gas, and 1.679 billion barrels of natural gas liquids. This indicates that there is a substantial yet-to-find potential and the prospectivity of Indian sedimentary basins is indeed good.

5.9.10 The trade-off between the Government take and investment, depending on the prospectivity perception, is complex and gets addressed by various host countries on a continuing basis. It is also pertinent to mention that the last word on exploration remains to be said.

## **5.10 Description of the Proposed Model, Based on Production Level & Price**

5.10.1 The proposed model is centred on a two-dimensional matrix, with an incremental production-based sliding scale combined with a fixed, price-sensitive scale. It proposes the production or the post-royalty value of the combined output of oil and gas to be shared between the Government and the Contractor. Under the proposed model, production-sharing between the Government and the Contractor will be linked to the average daily production and prevailing average of oil and gas prices in a well-defined period. A matrix has been designed, which incorporates both price bands and incremental production tranches, for computation of pre-tax production share between the Government and the Contractor. The indicative incremental production tranches with oil/gas price bands have been designed for various sectors, viz., on land, in shallow waters and in deep waters, separately for oil and gas. This has been done after duly taking into account relevant geo-technical and geo-economic factors and considering the anticipated production by studying the available historical data on Indian geological basins, size of reserves, productivity of wells, peak well-flow, etc. Oil/gas price tranches have been designed keeping in view the recent trends. However, the tranches suggested can be suitably modified or fine-tuned after due consideration.

5.10.2 The above would imply that for any given price situation which the Contractor faces in the market, Government's take should rise monotonically with rise in daily production, across incremental production tranches. Similarly for any given tranche of output per day, the government's share would rise monotonically with an increase in price as one moves across price-classes. The proportion of sharing should depend on the value of both the output per day and the price per unit of oil/gas. The formal presentation of the model of sharing centres around a two-dimensional matrix. The rows and columns of the matrix spanning the entire range of possible variation of price and output, divided into different classes representing different price and production tranches. Each production tranche specified in the table below paragraph 5.10.3 represents incremental production falling in the range of the tranche.

5.10.3 The production share for each combination of price-class and incremental production- tranche in the matrix would be biddable by the Contractor. As indicated above, the bid has to be progressive and incremental in terms of the Government take, i.e., the Government take will be in ascending order for corresponding increases in production and price. Thus, under the proposed system, Government take will be progressive with respect to both production and

prices. An indicative example for an offshore block is shown in the table below. By allowing companies the option of bidding the production share for different price classes and incremental production tranches, Government's take will get determined through a competitive bidding process.

SHALLOW WATER OFFSHORE BLOCK (OIL CASE)					
Daily Production  (Mbod)	Oil Price (\$/Bbl)				
	< or = 75	> 75 to < or = 90	> 90 to < or = 105	> 105 to < or = 120	> 120
	Government Take (%)				
< or = 10					
> 10 to < or = 30					
> 30 to < or = 50					

## 5.11 Description of Fiscal Terms

5.11.1 The proposed system will have the following fiscal components:

- i *Royalty*: Royalty will be paid to the Government from Gross Revenue. Fixed ad valorem rate of royalty is suggested for the proposed model. The present royalty structure for different categories of blocks may be continued.
- ii *Production Sharing*: Revenue, net of royalty, will be shared between the Contractor and the Government, based on the average daily production in a year/quarter, using a sliding scale calculation methodology. The Contractor will be required to bid the share in percentage terms payable to the Government as per the price-class and incremental production matrix. The average price for the quarter will be considered for determining the price for the calculation of Government's share of production.

- iii *Income Tax:* As per existing income tax laws, the Contractor will be required to pay income tax on his profit. Seven years tax holiday from the start of production is recommended for both oil and gas fields, except for ultra-deep water blocks (i.e., those blocks for which a significant part of the block is having a depth of more than 1500 metres).

5.11.2 The production share for each cell of the matrix will be biddable at the time of the submission of bid and the numbers specified in the winning bid will be agreed to in the PSC that will be signed between the Government and the Contractor.

5.11.3 Indicative production and price bands for on-land, shallow waters and deep waters, in case of both crude oil and natural gas, will be considered by the Government. However, Government would rather prefer competitive bidding and the profit split of the Government and Contractor's Take to be decided by competitive bids in the price-production matrix. Any abnormally low bid, especially in case of a single bid for a block, would require close scrutiny to safeguard the Government take.

5.11.4 In the proposed new model, no deductions will be allowed after the incidence of royalty and before the petroleum split between the Government and the Contractor. Thus, a major impact of the proposed model would be to provide the Contractor with the incentives for keeping costs down. Pegging the costs down will enhance the Contractor's profitability of operating the project.

## **6 Bidding Criteria and Bid Evaluation Criteria (BEC) in the Proposed System**

### **6.1 Bidding criteria in the proposed new system:**

- (i) Companies will be required to bid for the Government share of production, after royalty, as per the matrix provided. The bid has to be made separately for oil & gas cases.
- (ii) Bidding has to be progressive on Government take for each subsequent level of production as well as price tranche.
- (iii) Bidding in constant terms or fractional bidding will not be permitted.

### **6.2 Bid evaluation criteria (BEC):**

- (i) Government NPV @ 10% will be calculated for each price band separately for oil & gas only for the Government production share offered (excluding royalty and income tax) and summed up.
- (ii) Government NPV will be calculated on benchmarked production profile.
- (iii) Highest oil & gas price of each band and US \$ 140 / Bbl for oil and US \$ 12 / MMBtu for gas (as the case may be) for the highest tranche will be used for calculating Government NPV.
- (iv) Company offering highest NPV @ 10% combined for oil and gas can be awarded highest score on the fiscal package in the process for award of the block.

## **7 Technical Administration**

7.1 From the technical view-point, it will be important to monitor the production level in the proposed fiscal model as this will determine the tranche applicable for production-sharing between the Contractor and the Government. Based on the discovery-size, the production-profile generated by the Contractor for development of the discovery will require technical due diligence. Thus, approval of the Field Development Plan (FDP) will require meticulous consideration by the Management Committee (MC). Moreover, there may be instances of actual production level being different from the production level proposed to be achieved during FDP approvals.

7.2 The issue of reservoir management will also require careful technical consideration. Based on the production-sharing bid made by the Contractor, there may be a tendency to over-produce or under-produce for maximising commercial gains. It has to be technically ensured that the production levels approved or achieved are in accordance with the best technical practices. The rate of production should be sustainable and in accordance with the Good International Petroleum Industry Practices for such development projects, and excessive loss of reservoir pressure and rapid decline of production should not take place. The fundamentals of Petroleum Resource Management System (PRMS), developed by SPE, will be applicable for determining a specific project used to recover the reserves and %estimating+ the volume expected to be recovered from the project.

7.3 The Government will also ensure that production in the proposed model will be taken by the Contractor in a safe and workmanlike manner. The Government/DGH will retain the power to ensure that the reservoir is not flogged for short-term gains. Moreover, the Government will satisfy itself that all the equipment, materials, supplies, plant and installations comply with generally accepted practices and are kept by the Contractor in safe and working order.

7.4 Differences, disputes or claims arising out of or in connection with technical issues may be referred to a sole expert, who shall be an independent and impartial person of international standing, having relevant qualifications and experience, and appointed by mutual agreement between the Parties. However, the mechanism of Empowered Committee of Secretaries currently in place for NELP contracts may still be used as a first level forum to resolve contractual issues. A recommendation in this regard has been made separately in Section 15 in Chapter III.

7.5 Codification of Good International Petroleum Industry Practices (GIPIP) that are of relevance in the Indian geological set-up is required to be taken up at the earliest. This may resolve the issues facing the Contractors regarding ambiguities on technical and safety related aspects.

7.6 There may be graded penalties for various deviations/violations. There also has to be quantification of Liquidated Damages (LD).

## **8 Contractual Provisions**

### **8.1 Exploration period**

8.1.1 *Issues:* In the existing NELP PSC, the exploration period is restricted to seven/ eight years. Moreover, there is a timeline for commencing development of a gas discovery within ten years from the date of the first discovery well. Further, the issue of exploration in the Block/Field, beyond the exploration period stipulated in the PSC, is not clearly spelt out. For reasons of cost-recovery, it is perceived that Contractors may try to load the cost of further exploration on existing discoveries in the Block/Field thereby affecting the profit petroleum take of the Government.

8.1.2 *Proposed Changes:* Exploration period may be enhanced to ten years (with an initial period of six years, and a subsequent period of four years) in case of frontier, deep water blocks and ultra-deep water blocks. Moreover, due to the proposed basic shift in the fiscal model, any restriction on further exploration can be removed. Contractors may be allowed to carry out further exploration throughout the mining lease (ML) period in the area available to them under the ML. This will have a major impact on furthering hydrocarbon exploration.

### **8.2 Development of Discoveries in Deep Water and Frontier Areas**

8.2.1 *Issues:* (a) Development of these discoveries takes considerable time due to lack of infrastructure and cost-effective production technology. At times, a single discovery may not be techno-economically viable on stand-alone basis but may become economically viable on a cluster basis. (b) At times, proper technology may not be available at commercial rate to develop a discovery in frontier areas like ultra-deep waters. (c) In case the time taken for preparation and approval of the Field Development Plan (FDP) is long, little time is left for the Contractor to initiate development activities, particularly in case of offshore gas discoveries, within the timelines currently stipulated.



8.2.2 *Proposed Changes:* There may be contractual provisions for joint development of commercial discoveries made by the Contractor in adjoining blocks. In such cases, timeline for submission of a comprehensive development plan for more than one such discovery may be suitable to accommodate multiple discoveries with different dates. A suitable option may be the grant of Suspension of Operations to the Contractor on lines similar to what are applicable in the Gulf of Mexico.

### **8.3 Force Majeure**

8.3.1 *Issues:* (a) At present, *force majeure* notice has to be served by the Contractor within seven days of occurrence of the event.

8.3.2 *Proposed Changes:* (a) *Force majeure* notice period may be enhanced to thirty business days. (b) Article 3.5 may be made more specific with regard to turning down of an Operator's request for invocation of *force majeure*.

### **8.4 Appraisal Programme and Its Period**

8.4.1 *Issues:* (a) At present, the Contractor is not allowed to carry out any exploration during the appraisal period, even if additional exploration objectives are met at different stratigraphic levels in the appraisal area. (b) The Contractor is not allowed to integrate appraisal of contiguous discoveries made in similar geological set-up.

8.4.2 *Proposed Changes:* During implementation of the appraisal programme, the Contractor may be allowed to probe the potential of additional reservoirs, if any, through additional exploration activities for proper assessment of commercial viability within the Discovery Area. This would save time and money for probing hydrocarbon potential of such prospects by means of additional wells, at a later date.

### **8.5 Flexibility in Carrying Out Minimum Work Programme (MWP) Activities**

8.5.1 *Issues:* (a) In many cases, logistic, environmental, or other constraints make it difficult for the Contractor to achieve the committed MWP. This may

warrant change in planning of exploration inputs. (b) There are instances when in a given acreage, hydrocarbon occurrence is observed at shallower levels than envisaged earlier (with the deeper sequence turning out to be non-prospective) and there is a commitment for a specified number of deep wells. This requires the Contractor to pay Liquidated Damages (LD) for the remaining MWP wells, fixed on a per well cost basis for on-land (1 million US \$), shallow waters (3 million US \$) and deep waters (6 million US \$).

**8.5.2 Proposed Changes:** (a) The PSC may be made more flexible with regard to swapping MWP. Post award, if logistics and/or other constraints make a particular committed survey difficult, Government may consider carrying out an alternate survey, so long as state-of-the-art technology is utilised and the Contractor is spending equivalent or more money. (b) Provision may be introduced in the contract for permitting revision of target depth of wells, restructuring the MWP, and avoiding drilling of barren meterage.

## **8.6 Illogical Bidding in 'S' Type Blocks**

**8.6.1 Issues:** These blocks often witness bids with commitment of physical work programme defying technical logic. This is particularly so in case of a number of exploratory wells, as the Liquidated Damages (LD) for unfinished well in on-land block is only US \$ 1 million per well.

**8.6.2 Proposed Changes:** A clause for a minimum level of fulfilment of the work programme may be built in for qualifying for the requirement to pay LD before the contractor is allowed to quit the contract. This may be about 50% of the committed programme.

## **9 Role of the Government/DGH**

9.1 The most significant role of the Government/DGH in the proposed production-based sliding scale system will be to structure and design the field size distribution expectations within different areas (on-shore, shallow water and deep water) and across different basins. As exploration activity progresses, the field size expectations for oil & gas fields in on-shore, shallow water and deep water areas may undergo significant change which can be factored in for subsequent.

### **9.2 Management Committees:**

9.2.1 As there will be no element of cost recovery in the proposed new system, the functions of the Management Committee (MC) listed below, related to annual budgets, audited accounts and auditors may become redundant. Approvals related to these provisions are a major bone of contention between the Government and Contractors. Some of these functions, which no longer need to be done by the MC in the proposed new system, are:

- (i) annual budgets in respect of exploration operations and any revisions or modifications thereto;
- (ii) annual budgets in respect of the development operations and any revisions or modifications thereto;
- (iii) annual budgets in respect of the production operations and any revisions or modifications thereto;
- (iv) approval and adoption of audited accounts;
- (v) appointment of auditors; and
- (vi) procurement related issues.

9.2.2 Thus, in the proposed new system, routine business decision-making will be taken out of the purview of the MC, and Operators will have more freedom to carry out petroleum operations.

9.2.3 Monitoring under the new system will be limited to reservoir management, production volumes and safety aspects. The Government/DGH will essentially undertake roles related to technical/commercial supervision in the MC, such as:

- (i) review of proposal for an appraisal programme, or revisions or additions thereto;
- (ii) review of proposal for declaration of a discovery as a Commercial Discovery;
- (iii) approval of proposal of Development Plans, or modifications or revisions thereto;
- (iv) determination of a Development Area; and
- (v) collaboration with licensees and Contractors of other areas.

9.2.4 Although budgetary and cost-control related matters would be beyond the purview of MC and the State, the State/Government will have to ensure conservation and efficient inter-temporal use of resources through techno-economic appraisals and review of projects from time to time. Such appraisal would involve some budgetary or cost related issues at a normative level for defining the benchmark or reviewing a field development which are very site-specific. Reviewing is important for updating the normative benchmark, as necessitated by the dynamics of technology and that of performance due to learning by accumulation of operational experience. However, the jurisdiction of the MC in the appraisal or review need not mean approval of cost or investment by way of command and control. The purpose may be served by imposition of penalty or an appropriate market instrument.

9.2.5 Composition of the MC may remain the same as now, with two Government nominees and one member each to represent the companies constituting the Contractor. If the Contractor is a sole company, then such company shall have two members. One representative of the Government will be designated as the Chairman of the MC and another Government nominee will be designated as Deputy Chairman. The member designated by the Operator will be designated as the Secretary to the MC.

9.2.6 The MC shall not take any decisions without obtaining prior approval of the Government, where such approval is required under the PSC or any applicable law (including rules and regulations) of India. The MC shall obtain

such approval/decision, and convey the same to the Contractor with utmost expedition.

9.2.7 The MC, during the production phase, may at least meet once a quarter, as monitoring production levels becomes crucial from a commercial point of view. The new fiscal model being production and price driven, it will place a lot of emphasis on average production achieved during each month/quarter. However, meetings of the MC may be held more frequently at the request of any member. The Secretary, with the approval of the Chairman, will convene each meeting by notifying members in the manner prescribed in the current PSC.

9.3 *Pricing and Valuation of Petroleum:* Government will retain the rights stipulated in the existing PSC regarding pricing and valuation of the crude oil, natural gas and condensate. As sharing of profit petroleum will be based on a price and production matrix bid by the Contractor, pricing will become more important from the point of view of Government's revenue.

9.4 *Monitoring the Volume of Petroleum Produced:* As per the existing PSC, verification of the measurement of petroleum production is a function vested in the Government. As the sharing of the profit petroleum will be based on a price and production matrix bid by the Contractor, measuring production volumes will become more important from the point of view of Government's revenue. The provisions regarding petroleum produced and sold, and petroleum produced and permitted for internal consumption, will increasingly require monitoring by the Government.

9.5 *Other Contract Monitoring Provisions:* Several contract monitoring provisions, like Accounting Procedure, etc. will become superfluous as there will be no reimbursement of contract costs to Contractors. Thus, accounting procedures need not be monitored by the Government/DGH. This will facilitate Government/DGH in focussing better on monitoring of the technical aspects stipulated in the PSC provisions like those relating to reservoir monitoring, Recovery Factors (RF), tests to be accepted for oil & gas discoveries, etc.

## **10** Merits of the Proposed System

10.1 In the proposed system, PTIM and cost recovery mechanism is proposed to be dispensed with. This would address issues related to cost, if any, by the Operators and need for the Government to monitor the costs so as to safeguard own share of profit petroleum. Moreover, the share of profit petroleum to the Government will commence from the first day of production. In the existing fiscal model, profit petroleum to the Government may commence only when all contract costs have been recovered (in case of a 100% cost-recovery bid by the Contractor). The proposed changes will lead to a simple and transparent system with easy-to-monitor parameters of production and price. The proposed system, with no direct cost-recovery, is not directly sensitive to fluctuations in costs, unlike the existing system. It enhances the incentive for the Contractor to keep costs down. It is in line with the Government's broad objectives of efficiency in oil field operations and conserving scarce hydrocarbon resources.

10.2 The new model reduces efforts and time in examining and monitoring by the Management Committee (MC). It will enable greater concentration on monitoring of technical aspects for effective exploration and optimal exploitation of reservoirs. The proposed fiscal model also addresses the issue of windfall profits to the Contractor in case of a price surge. The proposed system will allow the development of smaller and marginal fields having low production rates.

10.3 Allowing companies the option of bidding the production share at various production levels and oil price tranches, should allow bidders to factor in the fiscal terms of contract as these will get determined by the marketplace. Moreover, to mitigate the risk of E&P companies, there is no minimum government share prescribed and the bidder is free to bid any non-zero share. The Contractor's cost recovery will be embodied in his share of production, which the Contractor will be free to bid.

10.4 The proposed system is much more flexible and investor-friendly in comparison to the systems obtaining in our neighbouring countries in Southeast Asia, like Myanmar and Indonesia. These countries, which have a cost-recovery mechanism, follow a more rigid and harsh fiscal regime. Myanmar, for example,

has cost-recovery, but also has signature, discovery and production bonuses, State participation, domestic market obligation, and various types of fees. Similarly, Indonesia has cost-recovery, and also signature bonus, three production bonuses, State participation, a very high percentage of royalty (20%), domestic market obligation, and a fixed percentage as government share. In contrast, the proposed system does not have any signature or production bonuses, State participation, or domestic market obligation, and has reduced royalty rates for certain areas and biddable share of production to the government, without any prescribed minimum government share. There should be no scope of collusion among bidders in a situation of scarcity turning the market into a supplier's one.

10.5 The proposed model is basically a royalty . tax regime, with production level payment. Government share arrived at through competitive bidding has to observe non-linearity with respect to marginal rate of appropriation, increasing with the output and shifting upwards for a price rise, for the government take to capture windfall gains on account of price rise. This model is being followed by a number of countries, with modifications. Columbia, for example, follows a royalty . tax regime, with a biddable %~~10~~+ factor, *i.e.*, additional biddable government participation in production, after royalty. It also levies an additional profit tax (windfall tax) linked to a base price, based on a formula. Many other countries follow a production linked or a production and price linked system with variations (like cost recovery, bonuses, State participation, windfall tax, and other levies). A few examples are Trinidad & Tobago, Tanzania, Ecuador, Equatorial Guinea, etc.

## 11

# Committee's Recommendations on ToRs (i) & (ii)

11.1 India has the experience of operating various E&P contractual and fiscal regimes since the onset of hydrocarbon exploration in the country. As the perception of hydrocarbon prospectivity in Indian hydrocarbon basins has evolved over the years, the tenets of fiscal and contractual models driving exploration and exploitation have also changed. While all the nomination acreages operated by National Oil Companies (NOCs) are under a Royalty . Tax regime, the Pre-NELP, Discovered Fields and NELP acreages are driven by the PSC regime.

11.2 As the PSCs progressed from the exploration stage to the development and production stage under successive NELP rounds, certain constraints have been observed in the working of the PSC contractual and fiscal model by both the Government and Contractors. These constraints are now increasingly overshadowing the basic Government objective of energy security through expeditious development of hydrocarbon resources available in the country. The extant fiscal model, with primary focus on recovery of upstream costs, has been found to be a major bottleneck in expediting exploratory work and is also lacking in incentive to keep costs down.

11.3 A new contractual system is being proposed to overcome the difficulties in managing the existing model based on the Pre-Tax Investment Multiple (PTIM) methodology and cost-recovery mechanism. The proposed model should overcome cost-related constraints in the existing PSC, which have led to delays in decision-making on exploration and development investments of the Contractor. The issue of cost-recovery in the existing PSC system and the concerns expressed by the industry and other stakeholders are inherent to the system. Therefore, a need was felt for a new system which does not have these difficulties and which will meet the Government's objective of promoting rapid exploration and development in this sector.



11.4 All the PSCs signed by the Government up to the ninth round of NELP will continue with the existing fiscal model, ensuring the sanctity of these contracts. Moreover, in the forthcoming rounds as well the PSC structure will be retained, albeit with a different fiscal model.

11.5 With the proposed model, gross production available from the field, whether oil or gas, will be shared between the Government and the Contractor on the basis of an incremental production-based sliding scale combined with the fixed, price-sensitive scale. The production tranches will be different for various sectors (on land, shallow water and deep water), and price bands will be based on historical and prevailing price trends. Production and price bands will be suitably designed after due deliberation and considering available historical data for Indian geological basins. The level of technical support required for this exercise will be high and will need to be ensured.

11.6 The production share for each cell of the matrix will be biddable, and the winning bid will be determined on the basis of competitive bidding. The bid has to be progressive and incremental with respect to the Government take, *i.e.*, the Government take will be in an ascending order for increases in production and price. The NPV of Government's share in revenue, using benchmarked production profiles for the block, will be one of the deciding criteria for assessing a bid.

11.7 The Government may not introduce a mandatory minimum percentage share for the highest price/production cell of the matrix. The Government would prefer the production share of the Government's and Contractor's take to be decided by competitive bids in the price-production matrix. However, any abnormally low bid, in case of a single bid for a block, which may be the result of cartelisation or information asymmetry, would require close scrutiny to safeguard government take.

11.8 The overall bidding parameters of the Minimum Work Programme (MWP) commitment and the fiscal package will remain the same as at present. Technical capability will also continue to have the same treatment as it obtains currently. Only the Bid Evaluation Criteria (BEC) for the fiscal package will change with the proposed changes in the fiscal model, although its weight in the overall bid may remain the same.

11.9 The model so proposed will be applicable for all future contracts, including Coal-Bed Methane (CBM) contracts. Only the production tranches will be changed, depending on historical data available at the time of award of CBM blocks.

11.10 As there will be no element of cost-recovery in the proposed system, the role of the MC or of the Government nominees on the MC will be largely related to monitoring and control of technical aspects. The functions pertaining to approval of annual budgets, audited accounts and auditors will not be required.

11.11 The new regime is expected to help overcome uncertainty with regard to the time involved in securing various categories of approvals from the MC.

11.12 In the existing model, the sharing of profit petroleum and the associated economic rent to the Government may be delayed as a result of the pattern of costs and investments by the contractors. However, in the proposed system, the Government will be able to capture economic rent in the form of royalty and revenue share of hydrocarbons, with the onset of production.

11.13 The Government will also be able to share the windfall profits in the event of a price surge or a geological surprise by way of a huge hydrocarbon find.

11.14 Other contractual bottlenecks for exploration and exploitation of hydrocarbons may be addressed with suitable amendments in the provisions for the exploration period, flexibility in carrying out the appraisal programme, development of discoveries in deep-water and frontier areas, *force majeure*, etc. (cf. paragraphs 8.1.2, 8.2.2, 8.3.2, 8.4.2, 8.5.2 and 8.6.2)

11.15 A major impact of the proposed model in the interest of hydrocarbon exploration will be that Contractors can be allowed to carry out further exploration throughout the Mining Lease (ML) period in the ML area.

11.16 It is perceived that prospectivity in offshore blocks along the Eastern and Western coastline is high and there is enthusiastic response from global majors. These blocks are in ultra-deep waters, which can be anywhere beyond 1,500 metres in depth. Further, along the Eastern coastline, reservoirs are

characterised by high pressure and high temperatures. The monsoon vagaries limit the weather window effectively to four months. Hence, the exploration and development of these blocks is costlier than shallow blocks. It needs to be compensated by a suitable fiscal package other than the existing seven-year tax holiday and biddable fiscal parameters. The committee recommends that the tax holiday can be extended to ten years from the date of first production in such ultra-deep water blocks.

11.17 Since the proposed fiscal regime would be new in the Indian context, the regime may be reviewed after five years.

## **Chapter III**

# **Managing the Contract Implementation of PSCs (ToR iii)**

## 12

## **Description of Contract Management by the Management Committee**

### **12.1 Constitution of the Management Committee**

12.1.1 A Management Committee (MC), consisting of the representatives of the Government and the Contractor, has been established under the Production Sharing Contract. The MC is chaired by the representative of the Government. In case of contracts signed for Pre-NELP exploration blocks and Medium Sized fields offered under development offers, the MC is chaired by the representative of the National Oil Company as being Licensee (ONGC/OIL) and a representative from DGH acts as 2<sup>nd</sup> Government Nominee. Director General, Directorate General of Hydrocarbons (DGH) chairs the MC for contracts signed under New Exploration Licensing Policy (NELP) and the representative from Ministry of Petroleum and Natural Gas has been nominated as 2<sup>nd</sup> Government nominee, and is the Deputy Chairman of MC. The representative from Integrated Finance Division (IFD), Ministry of Petroleum and Natural Gas participates in the MC as a Special Invitee. The member designated by the operator is Secretary of the Committee.

### **12.2 Functions of the Management Committee**

12.2.1 Under the NELP PSC, the MC has advisory and approval functions. The advisory functions of the MC during the Exploration Period covers, among other things, the Annual Work Programmes and Budgets in respect of Exploration Operations, proposals for surrender or relinquishment of any part of the Contract Area by the contractor, proposals for Appraisal Programme and the declaration of a Discovery as a Commercial Discovery and any other matter required by the terms of the Contract / which the Contractor decides to submit to MC for its review and advice. The matters which are submitted for approval of the MC include, inter alia, Annual Work Programmes and budgets in respect of development and production operations, proposals for approval of Development Plans (DP) or modification or revision thereof, determination of Development Area (DA), appointment of auditors, approval and adoption of audited accounts, etc., and any other matter required by the terms of the Contract to be submitted

for approval, or any other matter which the Contractor decides to submit to the MC, and any matters which the Government may refer to the MC for its consideration.

### **12.3 Procedures of the Management Committee**

12.3.1 The decision-making process, the frequency of MC meetings, and the venue of the meetings are specified in the contract. Unless agreed upon otherwise by the MC, the MC shall meet at least once every six months during the Exploration Period and thereafter at least once every three months or more frequently at the request of any member. The MC meeting is convened by the Secretary with the approval of the Chairman by notifying the members 28 days prior to such meeting. The Chairman or Deputy Chairman presides over the meetings of the MC and in their absence, any other member representing the Government present presides over the meetings. Secretary to the Management Committee is responsible, inter alia, for preparation of minutes. The meetings of the MC are required to be held in India, unless otherwise mutually agreed by the members of MC. All matters requiring the approval of the MC is generally approved by a unanimous vote of the members of MC. The MC may appoint legal, financial or technical subcommittee agreed by MC to consider any matter requiring approval or decision of the MC.

### **12.4 International examples on Supervision of Operations**

12.4.1 In Indonesia or Indonesian style contracts supervision is called management. The National Oil Company or State party is responsible for the management of the operations and the contractor is responsible for execution of the operations.

12.4.2 The contractor remains the operator where the contract provides for creation of a management committee. Such a management committee is intended either as an advisory committee or as a supervisory committee. When a management committee acts as an advisory committee its task is to discuss and review proposals prepared by the operator before they are submitted to the supervisory body, i.e. the State party for approval.

12.4.3 There is an elaborate system of supervision and cooperation between the State party and the Contractor prevalent in some of the international contracts which are similar to the system followed in respect of contracts signed from Fourth to Eighth round of bidding and Joint Venture Exploration Programme-1995. In such a system a joint management committee is established in which the State party and the Contractor are equally represented and decisions of the committee are taken unanimously. The annual work programmes and budgets are reviewed by the committee before it is submitted by the contractor to the State party for approval. For the plan of development, the committee submits the same to the State party and in turn the State party submits the plan to the ministry for approval. The joint management committee also has the responsibility of approving the acquisition of goods and services within the limits of approved budget.

## **13 Issues in the Existing Contract Management**

13.1 Directorate General of Hydrocarbons (DGH) has been entrusted with the responsibility for monitoring of PSCs awarded under Pre-NELP and NELP and field bidding rounds on behalf of Government of India. These PSCs require monitoring of exploration work commitment during exploration phase, and further monitoring of appraisal work and approval of development work, in case of any hydrocarbon discovery. During the course of implementation of various contracts, it has been observed that there are certain issues where clarity is required in order to avoid delays.

13.2 Issues have arisen during the course of PSC implementation and monitoring. These have arisen due to ambiguity in the interpretation of PSC clauses, rigid timelines for some petroleum operations, in some cases relaxation of good industry practices/standards and, delay in grant of statutory clearances.

13.3 The PSC provides for timelines for carrying out various petroleum operations during the course of implementation of the PSC for the Contractor and the Management Committee to adhere to. It has been observed that some of the periods provided for carrying out petroleum operations under NELP contracts have become rigid and inflexible. The duration for various operations in respect of NELP contracts were fixed by the Government keeping in view the need to expedite exploration, development and production activities in the country.

### **13.4 Difficulties in Implementation of the PSC**

13.4.1 DGH has stated that while carrying out the functions of monitoring, several difficulties have been faced in PSCs as the PSC is silent on some issues or there is ambiguity in interpreting some of the provisions. The monitoring of each PSC involves coordinating various Technical, Contractual and Financial matters. With limited manpower, managing various PSCs is becoming very difficult. Additionally, ambiguity in interpretation of some of the PSC provisions is adding to existing work load and inevitably leads to arbitration and court cases.



13.4.2 The issues with the existing contract management, as observed by DGH, basically fall into three categories:

- (i) Policy related issues
- (ii) Management/administrative issues
- (iii) Contractual issues

### **13.5 Policy Related Issues**

#### **13.5.1 Reduction of MWP in cases of blocks overlapping with SEZs, reserve forests, naval exercise areas, DRDO danger zones, National Parks, urban areas, firing ranges of Police, Armed Forces, etc.**

Exploration blocks are offered for bidding after securing clearance from various agencies. Subsequently, after the grant of Petroleum Exploration Licence (PEL), some of the agencies like Ministry of Defence, Ministry of Environment and Forests, state governments, etc. later deny permissions to carry out the work in these areas. There is no provision in the PSC for reduction in the MWP if a part of or the whole block is not available for operations.

#### **13.5.2 Longer Exploration Period in the North East and Other Troubled Areas**

- (a) Operators face several problems in the blocks of the North Eastern states due to natural calamities like floods and landslides, other problems like insurgency, or any local issues. Further, lack of required infrastructure like roads and bridges, non-availability of resources/services for E&P industry in the near vicinity also adds to the problems in carrying out the exploration work programme. These hurdles makes the exploration period of 7 to 8 years insufficient, and requests are often received from operators for extension in the duration of the exploration phase.
- (b) Problems like natural calamities, such as floods and landslides, are covered under the *force majeure* provisions of the PSC. However, problems arising due to lack of infrastructure, such as roads and

bridges, and non-availability of resources/services in the E&P sector cannot be addressed by the existing mechanism.

### **13.5.3 Drilling of Exploratory Wells / Appraisal Wells in the Mining Lease Area after Expiry of the Exploration Period**

- (a) Subsequent to approval of the Field Development Plan (FDP) Mining Lease (ML) is granted for commercial production of oil & gas from the ML area, as approved in the FDP. Contractors sometimes come with proposals to drill more exploratory wells in the designated ML area, with the objective of targeting new horizons.
- (b) The issue of drilling exploratory wells in the ML area after once the exploration period is already over is not clearly resolved in the PSC. In this regard, the relevant PSC provisions are cited below.
- (c) Article 11.3 of PSC (Mining Lease):

“Where a Development Plan has been approved pursuant to Article 10 and the Contractor has complied with the terms and conditions of the License and this Contract and is not in breach of any of the terms thereof, or the provisions of any law and subject to normal Government clearances/ approvals being obtained by the contractor as applicable before grant/ issues of the Mining Lease, the Government shall grant to the Contractor a Lease over the Development Area as agreed, subject to Article 11.4 to enable the Contractor to carry out Petroleum Operations in the Development Area in accordance with the Development Plan.”

This clause therefore, appears to bar the contractor from drilling exploratory wells in ML areas as these did not form part of the Field Development Plan.

### **13.5.4 Time for appraisal of discovery for on-land frontier blocks**

For deep-water blocks, time for appraisal of discovery is 30 months whereas for on-land frontier blocks it is 18 months only. The duration shall be extended to 30 months if requested by the contractor and recommended by the Directorate General of Hydrocarbons with the approval of its Director General for consideration of the Ministry.

### **13.6 Management / Administration Related Issues**

#### **13.6.1 Completion of the well under drilling**

At the end of final phase of exploration after completion of 7/8 years period, if drilling of a well under the Minimum Work Programme (MWP) is in progress, there is no provision in the PSC/policy for extension of the exploration period for completion of the on-going drilling and testing of the well. (Article 3.1, 3.6, & 3.7 and B.1 of the extension policy) In absence of any such provision in the PSC allowing the completion of drilling of the well, the Contractor may have to abandon the drilling and pay the cost of unfinished Work Programme as per Article 5.7 of the PSC, which will be detrimental to the overall exploration objective.

#### **13.6.2 Extension of time period for submission of Declaration of Commerciality (DoC) in respect of Hydrocarbon Discovery**

The PSC provides for stipulated time period for submission of Declaration of Commerciality (DOC), report for hydrocarbon discovery after implementation of Appraisal Work Programme. The time period for submission of DOC is mentioned vide Articles 10 & 21. Due to various reasons, proposals are received from Contractors for extension of DOC submission period. In absence of any provision in the PSC for extension of such time period on account of late submission, the DOC is not accepted, resulting in non-commercialization of the hydrocarbon discovery. This is also the case with submission of Development Plans.

#### **13.6.3 Waiver of reprocessing of 2D seismic data as per MWP, in the absence of availability of sufficient 2D legacy data**

Reprocessing of seismic data is one of the biddable parameters and the quantum committed by the bidder while bidding becomes the committed MWP under the PSC. The Contractor bids the quantum, based on data availability mentioned in the bid documents. DGH collects seismic data from the previous Operator and provides the same to the contractor to enable him take up reprocessing. In some cases, part of the data provided to the Contractor is not retrievable/available, and the Contractor only reprocesses the part of the data which is retrievable/available.

#### **13.6.4 Change in status of the company as a result of merger or amalgamation**

Whenever there is change in status of company, due to a change of name or amalgamation due to court orders etc., there is no provision in the PSC to regularize such change, with immediate effect. Government procedures for approval take time. Documents submitted, relating to statutory levies and other contractual obligations like Bank Guarantee (BG), are not valid till amendments are made to the PSC after Government approval.

#### **13.6.5 Swapping of 2D and 3D seismic Minimum Work Programme**

There is no provision to swap one work programme of MWP with another, in case the Operator fails to carry out a particular committed work programme, even in case of technical merit; for example, in case of swapping of 2D seismic MWP with 3D seismic MWP.

#### **13.6.6 Entry into subsequent exploration phases, after paying cost of unfinished work programme of the previous phase**

If the committed minimum work programme of an exploration phase is not completed, the Contractor has to pay the cost of the unfinished work programme to the Government, as per Article 5.7 of the PSC. However, the PSC is silent about whether or not after paying the cost of the unfinished work, the Contractor can enter the next phase.

**13.6.7 Condoning delay in the submission of Bank Guarantee, requests for extension (Article 3.5), submission of Appraisal Work Programme and budget, Declaration of Commerciality (DoC), Field Development Plan (FDP) etc.**

It is observed that, at times, an Operator submits the Bank Guarantee, request for extension (Article 3.5), Appraisal Work Programme and budget, Declaration of Commerciality (DOC), Field Development Plan (FDP) etc. after the expiry of timelines stipulated in the PSC. There is no provision in the PSC for condoning such delay, even if the delay is of a very short duration.

**13.6.8 Drilling of Appraisal Wells after submission of Declaration of Commerciality (DoC)**

- (a) DOC is submitted by the Contractor after carrying out the Appraisal Work Programme, which includes the drilling of Appraisal Wells. In some of the discoveries, it is observed that the Contractor carries out drilling of additional Appraisal Wells even after submission of the DOC report.
- (b) Drilling of additional Appraisal Wells is not allowed as the Contractor has already carried out drilling of Appraisal Wells as per the reviewed appraisal programme and has already submitted the DOC report based on the said work.

**13.6.9 Probing additional reservoirs during the appraisal programme**

- (a) During implementation of the Appraisal Programme, the Contractor should be allowed to probe the potential of additional reservoirs, if any, through additional exploration activities for proper assessment of commercial viability within the Discovery Area.
- (b) DGH has suggested that during implementation of the Appraisal Programme, the Contractor should be allowed to probe the potential of additional reservoirs, if any, through additional exploration activities for proper assessment of commercial viability within the Discovery Area. The Contractor may be permitted to probe additional reservoirs while carrying out appraisal

programme, subject to ring-fencing the cost of exploration till commerciality is proved to DGH's satisfaction.

### **13.7 Contractual Issues**

#### **13.7.1 Cost Petroleum: Concerns regarding inflating of costs, gold-plating and cost inefficiency; possibility of misuse of any discretion**

- (a) Profit is shared between the Government and the Contractor as per the provisions of Article 16. Expenditure incurred in petroleum operations is treated as allowable Contract Cost under Article 15. Audited accounts are approved by the Management Committee under Article 6. Audit is done by auditors appointed by the Management Committee, followed by Government audit.
- (b) DGH is required to maintain a database for each item of cost of the activities carried out by the Contractor during petroleum operations in the block. This database may be generated activity-wise for each block/basin in order to benchmark. Cost recovery needs to be examined on the basis of benchmarked cost.

#### **13.7.2 Limits on Exploration Cost under Article 15.13**

The PSC envisages allowing recovery of actual expenditure without any limit in respect of petroleum operations. Limiting cost in respect of the Minimum Work Programme will only add to administrative procedure, without value addition, since the Contractor may be able to secure Government approval by demonstrating the underlying cash flow. The purpose of this provision is to prevent bidders from underestimating the cost of the Minimum Work Programme in order to reduce their net worth requirement for bidding for the award of PSC under NELP.

#### **13.7.3 Government Take as a basis for evaluation of development plan and annual work programme budget**

- (a) Prior to development operations, the Management Committee approves a long term development plan based on a detailed

proposal from the Contractor for the construction, establishment and operation of all facilities and services for and incidental to the recovery, storage and transportation of petroleum from the proposed Development Area to the Delivery Point, together with all data and supporting information (Article 10.7).

- (b) On an annual basis, as soon as possible after the Effective Date, and thereafter within ninety (90) days before commencement of each succeeding year, the Contractor shall submit to the Management Committee the Work Programmes and the budgets relating to petroleum operations to be carried out during the relevant year (Article 5.9). Work Programme and budgets, and any modifications or revisions thereto, relating to exploration operations shall be submitted to the Management Committee for review and advice. Work Programmes and budgets related to development and production operations, and any modifications or revisions thereto, shall be submitted to the Management Committee for approval (Article 5.11).

#### **13.7.4 Issue: Cost of unfinished work programme**

- (a) As per the PSC, if the Contractor fails to complete the committed Work Programme during the exploration phase, he is required to pay compensation to the Government equivalent to the cost of the committed Work Programme.
- (b) The cost of work programme not done is notional, and its estimation is subjective. Investigating agencies have questioned the computations and the issue remains inconclusive.

#### **13.7.5 Compliance with the PSC procedure by the Operator for procurement of goods & services**

- (a) Appendix-F of the Accounting Procedure provides for procedures to be adopted by the Operator for the acquisition of goods and services for carrying out petroleum operations in a block. For the purpose of value of the materials charged to the accounts under the Contract, these costs for procuring goods and services shall

not exceed those currently prevailing in normal arms length transactions in the open market.

- (b) The PSC does not envisage any role for the Management Committee (MC) in procurement to be carried out by the Contractor. As per the provisions of the PSC, it is the Contractor who has to adhere to the procurement procedure laid down in the PSC. Hence, checking or certifying transactions made by the Contractor towards procurement of goods and services is not possible on the part of DGH.

#### **13.7.6 Issue: Consequence of *Force Majeure***

In the existing PSCs, notice is to be served within 7 days of occurrence of the event. There is no clarity with regard to statutory payments, including BG, in case *force majeure* is prolonged for over a year.



## **14 Stakeholder Views on Contract Management**

14.1 The Association of Oil & Gas Operators (AOGO) stated that Management Committees (MC) should focus on taking decisions of a more strategic nature so as to maximize E&P activities with optimal investments. Moreover, MC approvals should only be required for Field Development Plan (FDP) and non-exploration related Work Programme and budget (WP & B). Before the FDP stage, the role of the MC may be advisory in nature and not that of an approving body. AOGO also stressed the need for codification of best practices, with regular updates, strengthening of the dispute resolution mechanism, and establishment of a brainstorming group.

14.2 BG India (BG) recommended ensuring technical oversight over decisions taken in Management Committees (MC). The MC may review development plans, capex projections and production profiles, and may allow a flexible approach on technical merits. BG also requested for providing a single-window clearance to avoid procedural delay.

14.3 British Petroleum (BP) emphasized the need for expediting resolution of issues and clearly defining the roles and responsibilities of the Ministry, DGH and the Contractor.

14.4 FICCI recommended provision of an independent and technically competent forum to facilitate decision-making, holding meetings of the MC in a timely manner, simplifying contract administration, and introducing a speedy dispute resolution mechanism.

14.5 GEECL stated that it does not have any major contractual issues with the Government in its CBM contracts.

14.6 HOEC suggested that the MC should focus on strategic issues with a mandate to accelerate exploration initiatives, reduce time to commence oil / gas

production from a discovery, and maximize recovery of reserves. For emergency / exigent issues, the MC should be able to consider proposals through circulation of resolutions. Annual review meetings may be convened by MoP&NG to monitor progress and the performance for blocks, based on a financial materiality threshold.

14.7 JTI stressed upon the need for having a Technical Expert Panel (TEP) to resolve technical disputes. The Government and the Operator may nominate one expert each to the TEP, who together will select the third expert. Decisions taken by the TEP should be binding on both parties.

14.8 ONGC recommended timely holding of MC meetings, coupled with approval/review of proposals within the timelines provided in the PSC.

14.9 RIL averred that the PSC recognizes complexities of the project management cycle and, therefore, authorizes the Operator (not the MC or the Government) to conduct petroleum operations on behalf of the Contractor.

## 15

# Committee's Recommendations on ToR (iii)

### 15.1 Policy Related Issues: Constitution of an Inter-Ministerial Committee

15.1.1 As many contract management issues hampering execution of subsisting PSCs are policy related, the committee recommends the constitution of an Inter-Ministerial Committee to suggest policy solutions to these issues to the Ministry of Petroleum & Natural Gas (MoP&NG), which may obtain CCEA's approval.

15.1.2 This Inter-Ministerial Committee may have representatives from the Ministries of Petroleum & Natural Gas, Environment & Forests (MoEF), Defence, Finance, and Law & Justice. For issues pertaining to Coal-Bed Methane (CBM), a representative from the Ministry of Coal may be co-opted.

### 15.2 Issues concerning Contract Management and the Fiscal Regime

15.2.1 There is frequent criticism that presence of Government nominees on the Management Committee (MC) results in a conflict of interest between regulation and proprietorship. However, a similar situation prevails in many sectors of the economy, including the banking sector. Government, as the owner of petroleum and natural gas, engages contractors as per the terms of an agreement to explore, extract and monetise these resources. Hence, the MC should be seen as a joint effort to optimise the results for the owner and the contractor. However, as the owner of the resources, the responsibility of their management rests with the Government.

15.2.2 To facilitate smooth functioning of the MC, both the representatives of the Government on the MC may devise an internal mechanism to act collectively in the decision-making process and address the issues jointly, in a firm manner. DGH and MoP&NG should firm up Government's stand before the MC meeting.

15.2.3 Decisions of the MC should be quick, as per contractual provisions, and, as far as possible, MC resolutions should be signed on the date of meeting itself.

MC meetings may always include Action Taken Notes / Action-points from the last meeting as the first agenda item. Approval/review of any decisions taken by the Contractor in between two MC meetings should also be an agenda item. It may also be ensured that the periodicity of MC meetings under PSC provisions is adhered to.

15.2.4 In any case, if unanimity between the Government nominees on any particular item on the MC agenda cannot be achieved within a reasonable period of time, the issue may be referred to the Empowered Committee of Secretaries (ECS), as recommended below.

### **15.3 Empowered Committee Mechanism**

15.3.1 An analysis of pending issues indicates that most of them are due to minor deviations from the PSC framework. A majority of these concern timelines prescribed in the PSC. There are also issues which can be resolved by a constructive reading of the PSC. Government needs to allow certain flexibility on issues which do not affect its interest adversely. The timelines for various activities is one major issue on which Government can be lenient to a certain extent. The need for this was accepted and a policy framework for condoning delays during exploration was proposed by an Empowered Committee of Secretaries (ECS) and approved by CCEA in 2006. This system is working well as it set up a system of incentives and disincentives to encourage quick exploration. However, no such policy was devised for later phases of appraisal, development and production as there were very few NELP blocks in later phases of contract at that time.

15.3.2 There is an existing mechanism of Empowered Committee of Secretaries (ECS) approved vide Cabinet Committee of Economic Affairs (CCEA) Resolution dated 2<sup>nd</sup> December, 2003 to consider extension in the exploration period beyond the timelines stipulated in the PSC, depending upon the exigencies prevailing in the Block. The CCEA Resolution empowers the ECS for extension of exploration periods in Pre-NELP and NELP Blocks. The same ECS can be invested with powers to consider extension of other timelines prescribed in the PSC pertaining to appraisal, submission of the commerciality, Field Development Plan submission, etc. As the Ministries of Law and Finance are represented on this committee, a comprehensive government view can emerge. This

arrangement can resolve the anxieties of government staff dealing with the contract and ease decision-making. Further, this committee may also be empowered to reconcile and resolve minor technical disputes by including experts on the subject as special invitees. Selection of these experts may be done from the Government, regulatory organisations, and national scientific and technological organisations, while ensuring that no conflict of interest exists for such persons. Whenever such dispute resolution is being resorted to, specific consent of the Contractor should be obtained.

15.3.3 The committee recommends that all such issues raised during the entire period of implementation of existing contracts may be considered by the ECS, which has certain delegated powers under NELP. The ECS would operate in a time-bound manner.

#### **15.4 Codification of Good International Petroleum Industry Practices (GIPI)**

15.4.1 On technical and safety related issues the committee recommends that, DGH may undertake codification of Good International Petroleum Industry Practices (GIPI) that are of relevance to the Indian geological set-up. This may be done by a Working Group under the chairpersonship of Director General, Hydrocarbons and having experts from the Directorate General of Hydrocarbons, with nominees from MoP&NG, MoEF, Defence Research and Development Organization (DRDO) and other expert agencies. In case of ambiguities on technical and safety related aspects, the Contractor may refer the issues to this Working Group.

15.4.2 The Directorate General of Hydrocarbons (DGH) may be strengthened to render independent technical advice to the Government. DGH may recruit independent experts (who shall not be entrusted with representing the Government on the MC) for its core functions of reservoir, safety and other technical aspects of contract management.

# **Chapter IV**

## **Monitoring and Audit of Government Take**

### **(ToR iv)**

## **16 Audit of Accounts under the PSC**

**16.1 Article 25 of the PSC (Annexure C):** This provides for Government Audit in line with the Accounting Procedure provided in the contract. The objective of the Accounting Procedure is to ensure proper control over the flow of expenditure and the booking of costs in accordance with Generally Accepted Accounting Principles (GAAP).

**16.2** Accounting Procedures set out principles and procedures of accounting:

- i. to classify costs, expenditures and income, and to define which costs and expenditures shall be allowable for cost recovery and profit sharing.
- ii. to specify the manner in which the Contractor's accounts shall be prepared and approved; and
- iii. to address numerous other accounting related matters.

**16.3 Audit Controls:** There are two levels of audit prescribed under Article 25 of the PSC which enables the Government of India to conduct audit, the first-level audit being by the auditor appointed by the Management Committee for the PSC, and the second-level audit being by the Government either through its own representatives or through a qualified firm of recognized chartered accountants.

**16.4 Background of Audit by CAG:** In November 2007, the Ministry of Petroleum & Natural Gas requested CAG to conduct a special audit of Production Sharing Contracts for eight blocks from where substantial revenues were being generated in the form of royalty and profit petroleum. Pursuant to this request, CAG initiated audit of four oil & gas producing blocks (KG-DWN-98/3, Panna-Mukta, Mid & South Tapti and RJ-ON-90/1) for the financial years 2006-07 and 2007-08. In addition, CAG also carried out audit of PSC records available in DGH/MoP&NG in respect of 16 blocks shortlisted by CAG. CAG submitted its report in August 2011, which is under examination by the Public Accounts Committee. In this report, CAG indicated that it will audit these blocks in the coming years also.

In May 2012, it was decided that CAG would undertake audit of KG-DWN-98/3 for the years 2008-09 to 2011-12 and of Panna Mukta PSC and Mid and South Tapti PSC for the years 2006-07 to 2011-12. The Contractors were informed accordingly. CAG also commenced audit of RJ-ON-90/1 for the years 2008-09 to 2011-12 and audit of Kharsang PSC, CY-OS-90/1 (PY-3), PY-1 and CB-ON-7 for the years 2007-08 and 2008-09.

**16.5 Issues Raised by Contractors:** In pursuance of CAG's audit programme, the Contractors were asked by the Ministry of Petroleum & Natural Gas to provide access to all relevant information, documents, and accounts to the CAG. However, the Contractors contested this and made the following demands:

- (a) The audit should not be a Performance Audit and should only be an accounting audit restricted to PSC provisions.
- (b) The Audit report should be kept confidential and should not be subjected to scrutiny by any third party.
- (c) Any information obtained during the audit of contract records should not be used or associated with any other audit conducted by the CAG.
- (d) Audit for the period beyond two years should be only as per Contractor's consent as there are no exceptional circumstances to cover it within the scope of the Accounting Procedure under the PSC.

16.6 In this context, CAG clarified that audit of profit petroleum, which is in the nature of non-tax revenue, is a statutorily mandated duty of CAG (Section 16 of CAG Act, 1971). It also informed that all audit reports of CAG will be placed before Parliament, as per Article 151 of the Constitution of India.



## **17** Audit by the CAG

### **A. PROVISIONS FOR AUDIT IN PUBLIC INTEREST BY THE CAG**

17.1 The provisions for audit in public interest are given in section 20 of the Comptroller and Auditor General's (Duties, Powers and Conditions of Service) Act (DPC Act), and these are as under:

Section 20 (1): "Save as otherwise provided in section 19, where the audit of the accounts of any body or authority has not been entrusted to the Comptroller and Auditor-General by or under any law made by Parliament, he shall, if requested so to do by the President, or the Governor of a State or the Administrator of a Union territory having a Legislative Assembly, as the case may be, undertake the audit of the accounts of such body or authority on such terms and conditions as may be agreed upon between him and the concerned Government and shall have, for the purposes of such audit, right of access to the books and accounts of that body or authority.

Provided that no such request shall be made except after consultation with the Comptroller and Auditor-General."

Section 20(2): "The Comptroller and Auditor-General may propose to the President or the Governor of a State or the Administrator of a Union territory having a Legislative Assembly, as the case may be, that he may be authorised to undertake the audit of accounts of any body or authority, the audit of the account of which has not been entrusted to him by law, if he is of opinion that such audit is necessary because a substantial amount has been invested in, or advanced to, such body or authority by the Central or State Government or by the Government of a Union territory having a Legislative Assembly, and on such request being made, the President or the Governor or, the Administrator, as the case may be, may empower the Comptroller and Auditor-General to undertake the audit of the accounts of such body or authority."

Section 20(3): “The audit referred to in sub-section (1) or sub-section (2) shall not be entrusted to the Comptroller and Auditor-General except where the President or the Governor of a State or the Administrator of a Union territory having a Legislative Assembly, as the case may be, is satisfied that it is expedient so to do in the public-interest and except after giving a reasonable opportunity to the concerned body or authority to make representations with regard to the proposal for such audit.”

## **B. AUDIT OF PSC ACCOUNTS BY CAG**

17.2 The parameters under which the audit of Production Sharing contract (PSC) can be undertaken by the CAG are detailed in succeeding sub-paragraphs:-

17.2.1 Under Section 16 of the DPC Act , % shall be the duty of the Comptroller and Auditor-General to audit all receipts which are payable into the Consolidated Fund of India and of each State and of each Union territory having a Legislative Assembly and to satisfy himself that the rules and procedures in that behalf are designed to secure an effective check on the assessment, collection and proper allocation of revenue and are being duly observed and to make for this purpose such examination of the accounts as he thinks fit and report thereon.+As Profit Petroleum is a non-tax revenue payable into the Consolidated Fund of India, CAG is constitutionally mandated to audit the same under Section 16 of the DPC Act.

17.2.2 For the purpose of the PSC, a separate audit needs to be done under Section 1.9 of the Accounting Procedure given in the Production Sharing Contract. Such audit can be entrusted to CAG, as provided for in Section 20 of the DPC Act. Such an audit is to be an audit as set out in the preamble to the Accounting Procedures. The PSC clearly enunciates the purpose of the accounting procedure in--

- Section 1.1: “Generally, the purpose of this Accounting Procedure is to set out principles and procedures of accounting which will enable the Government of India to monitor effectively the Contractor’s costs, expenditures, production and income so that the Government’s

entitlement to Profit Petroleum can be accurately determined pursuant to the terms of the contract.”

- Section 1.9.1: “The Government shall have the right to inspect and audit all the record and documents supporting costs, expenditures, expenses, receipts and income, such as Contractor’s accounts books, records, invoices, cash vouchers, debit notes, price lists or similar documentation with respect to petroleum operations conducted hereunder....”
- Section 1.9.3: “The Government or its auditors shall be entitled to examine and verify all charges and credits relating to the Contractor’s activities under the contract and all books of account, accounting entries, material records and inventories vouchers, payrolls, invoices and any other documents, correspondence and records considered necessary to audit and verify the charges and credits.”

Thus, the scope of audit by the Government through its representatives is very wide and is aimed at fulfilling the purpose set out in Section 1.1, viz., accurate determination of Government’s entitlement to Profit Petroleum. The CAG, consequently, while doing the audit under the provisions of the Production Sharing Contract (PSC), shall have the right to conduct the audit to fulfil the purpose mentioned above.

17.3 The PSC is a contract between the Union of India and the Contractor. The Union of India consists of the Parliament, the Executive and the Judiciary. Any audit report produced by the CAG or any other auditor appointed by the Government under the provisions of the Production Sharing Contract shall be accessible to all the wings of the Union of India. The confidentiality clause provided under Article 26.4 of the PSC is applicable only against a third party for the contract and not against the Parliament and other wings of the Government, including the CAG.

17.4 While the audit under Section 1.9 of the Production Sharing Contract has a fixed timeline, which bars the extension of this timeline save under exceptional circumstances (section 1.9.1 of the Accounting Procedure in the PSC), audit under Section 16 / Section 20 of the DPC Act has no time limit and any irregularities found such audit is actionable under the relevant laws.

17.5 It is essential that audit under Section 1.9 of PSC's Accounting Procedure be conducted by CAG either concurrently with or prior to audit of the Ministry with respect to the PSC concerned. This will ensure that decision-making processes in determining profit and cost petroleum by Government are not impeded.

## **18 Recommendations on ToR (iv)**

18.1 Out of a total of 228 active PSCs, entered into up to Round IX of NELP, for which audit is to be conducted, audit by CAG is essential for PSC blocks where there are petroleum discoveries as correctness of cost recovery would be more relevant only in these blocks. Audit of blocks where no exist discoveries may be conducted by engaging qualified accounting firms. PSCs may be categorized as follows for the purpose of audit:

- a) **Exploration phase PSCs:** Audit of selected blocks to be carried out by CAG, with the remaining to be carried out by CAG-empanelled auditors.
- b) **Development phase PSCs:** Audit to be conducted by CAG in all important and financially critical blocks. Such audit can be done once in two years (in line with the timelines suggested in the PSC) for the selected blocks by CAG, while in all other years this task can be performed by audit firms empanelled by CAG. Audit of the remaining blocks can be entrusted to auditors empanelled with CAG, with their audit reports being reviewed by CAG.
- c) **Production phase PSC:** Audit of selected blocks to be carried out by CAG, with the remaining blocks to be carried out by CAG-empanelled auditors.

18.2 Audit may be carried out by the office of CAG in accordance with financial materiality. The concept of materiality is a convention within auditing and accounting relating to the importance/significance of an amount, transaction, or discrepancy. The objective of an audit of financial statements is to enable the auditor to express an opinion whether the financial statements are prepared, in all material respects, in conformity with an identified financial reporting framework. For this, accounts of blocks would be sent to the CAG, for selection of blocks for audit by CAG. Periodicity of audit for various blocks may be decided by the CAG keeping in view the timelines suggested in the PSC. This will become a regular feature. As such, there would be no requirement for requesting CAG for a special audit every time.

18.3 The audit criteria adopted by the CAG can be shared with auditors carrying out audit under the PSC for them to follow while auditing those blocks that are not being audited by CAG.

18.4 As the element of cost recovery is not applicable to CBM blocks and nominated blocks, CAG audit for such blocks may not be required, and production monitoring through field surveillance may be considered adequate. Similarly, in the case of the new fiscal regime recommended in relation to the committee's terms of reference (i) and (ii), audit by CAG would not be necessary.

18.5 Audit by CAG may be carried out within a period of two years of the financial year under audit, as specified in PSCs. This will resolve many issues relating to exploration and production activities. Further, where investment is huge (a \$1 billion threshold may be adopted), a suitable mechanism of concurrent audit may be considered.

18.6 Audit by CAG under Section 1.9 of the PSC should be prior to performance audit of the Ministry so that corrective actions emerging from CAG audit could be taken up by the Government in order to protect the Government revenue. The CAG audit is to be carried out strictly as per the provisions of the PSCs. Performance audit, normally done by CAG for the Ministry, can address other concerns of the auditor.

## **Chapter V**

### **Gas Pricing Mechanism**

**(ToR v)**

## 19 Structure of the Indian Gas Market

19.1 The Indian gas market is predominantly monopolistic in its operation due to a huge demand & supply gap. There are only a few producers whereas the number of consumers is large and they have a huge demand. Price is administratively determined for each source of supply. The gas market is still in a growing phase and it will be many years before the demand-supply gap is bridged.

19.2 Over the 12<sup>th</sup> Five-Year Plan period, a major proportion of growth in demand is likely to come from the power and fertilizer sectors. Power sector consumption, which is currently at 61 mmcmd, is projected to translate into a demand of 207 mmcmd by 2016-17, while the current fertilizer consumption of 37 mmcmd is projected to translate into a demand of 106 mmcmd by 2014-15 and stay at that level thereafter. These demand projections are highly price-sensitive. Other sectors, which are relatively price-insensitive and which currently consume around 68 mmcmd, will translate into a demand of 153 mmcmd by 2016-17. The total demand is likely to grow from 166 mmcmd currently to 466 mmcmd in 2016-17, with a compound annual growth rate of 18.75%.

### Sector-wise Demand of Gas during the 12<sup>th</sup> Five-Year Plan

Sector	2012-13	2013-14	2014-15	2015-16	2016-17
Power*	135	153	171	189	207
Fertilizer**	55	61	106	106	106
Demand (Price-Elastic) - Sub-Total	190	214	277	295	313
City Gas***	15	19	24	39	46
Industrial***	20	20	22	25	27



Petrochemicals / Refineries / Internal Consumption***	54	61	67	72	72
Sponge Iron / Steel***	7	8	8	8	8
Demand (Relatively Price-Inelastic) - Sub-Total	96	108	121	144	153
<b>Total Demand</b>	<b>286</b>	<b>322</b>	<b>398</b>	<b>439</b>	<b>466</b>

Source: (\*) Ministry of Power

(\*\*) Ministry of Finance

(\*\*\*) Report of the Sub-Group on Demand Estimates for Petroleum Products -- 12<sup>th</sup> & 13<sup>th</sup> Plans

Note: The above demand projections assume price inelasticity.

19.3 That there is a significant demand-supply gap is evident from the above demand projections coupled with the gas availability projections for the same period, which are as under:

**Total Projected Gas Availability during the 12<sup>th</sup> Five-Year Plan Period**

<b>12th Five-Year Plan (Figures in mmscmd)</b>					
	<b>2012-13</b>	<b>2013-14</b>	<b>2014-15</b>	<b>2015-16</b>	<b>2016-17</b>
Domestic Availability	124	149	170	177	209
Imports . LNG	63	87	87	129	150
<b>Expected Total Availability</b>	<b>187</b>	<b>236</b>	<b>257</b>	<b>306</b>	<b>359</b>

19.4 Domestic gas is sourced primarily from nomination fields of ONGC and OIL and the joint venture (JV) fields operated by RIL (KG-D6), British Gas (Panna-Mukta & Tapti), Cairn Energy (Ravva), NIKO Resources, etc. The

balance demand is met through imports of Regasified LNG (RLNG) by Petronet LNG Limited (PLL) and GAIL. The supply of gas from all sources during 2011-12 was as under:

<b>Source</b>	<b>Quantity (mmscmd)</b>
APM (from nomination fields)	50.64
Non-APM (from nomination fields)	7.45
NELP	42.41
Other Domestic JV Gas	14.01
RLNG	39.62
Coal-Bed Methane (CBM)	0.20
<b>Total</b>	<b>154.43</b>

The company/field-wise distribution is as under:

<b>Sl. No.</b>	<b>Source</b>	<b>Selling Price of Gas</b>	<b>Average supply during 2011-12 (mmscmd)</b>
1	NOCsqAPM Gas	\$2.52 - \$ 5.25/mmbtu	50.70
2	NOCsqNon-APM Gas	\$4.2/mmbtu	7.45
3	PMT#	\$ 4.2 - \$ 5.73/mmbtu	11.03
4	Ravva*	\$ 4.2/mmbtu	0.53
5	Ravva Satellite	\$ 4.3/mmbtu	0.97
6	KG-D6	\$ 4.2/mmbtu	42.32
7	Niko-Hazira	\$ 2.673 - \$ 5.346/mcf	0.48
8	CB-OS/2	\$ 4.75 - \$ 6.22/mmbtu	0.52

9	CB-ONN-2000/2	\$ 6.6/mcf	0.08
10	Hermac	Rs. 9.02 - Rs. 11.67/scm	0.01
11	Joshi Technologies (Dholka)	Rs. 4.80/scm	0.02
12	CBM	\$ 5.1 - \$6.79/mmbtu	0.20
13	Focus Energy (RJ-ON/6)	\$ 4.11/mmbtu	0.17
14	HOEC (PY-1)	\$ 3.63/mmbtu	0.38
15	Term R-LNG**	\$ 6.97 - \$ 9.06/mmbtu	25.51
16	Spot R-LNG**	\$ 12.52 - \$ 17.44/mmbtu	14.11
<b>Total</b>			<b>154.48</b>

mmscmd: Million standard cubic metres per day

mmbtu: Million British Thermal Units

mcf: Thousand cubic feet

scm: Standard cubic metre

# Purchase price of Panna Mukta Gas is \$ 5.73/mmbtu & of Mid Tapti is \$ 5.57/mmbtu.

\* Purchase price of Ravva Gas is \$ 3.5/mmbtu.

\*\*R-LNG prices are ex terminal prices, exclusive of regasification charges

19.5 It is pertinent that there does not seem to be any scope for increasing the supply of gas in India in the short term, due to infrastructural constraints in the gas sector which include:

- I. Inadequate capacity of RLNG terminals for importing gas

- II. Long gestation periods of projects in the pipeline:. The KG-D6 discovery was developed in a record time of 5.5 years. It is not likely that other discoveries would be developed in such a short time because there are inherent difficulties in developing fields in ultra-deep waters, which require highly strategic planning for technology and geological complexities.

19.6 Hence, it is quite likely that over the next five to seven years the Indian gas market will move towards becoming oligopolistic, where the market will be distributed amongst a few sellers, with a huge demand-supply gap persisting.

## **20** Current Gas Pricing Formation in India

20.1 There are broadly two pricing regimes for gas in the country . one for the gas priced under the Administered Pricing Mechanism (APM), and the other for the non-APM or free-market gas. The price of APM gas is set by the Government principally on a cost-plus basis. As regards non-APM/free-market gas, this could also be broadly divided into two categories, namely, (i) imported Liquefied Natural Gas (LNG), and (ii) domestically produced gas from New Exploration Licensing Policy (NELP) and pre-NELP fields.

### **20.2 Administered Pricing Mechanism (APM)**

20.2.1 Gas produced from existing fields of the nominated blocks of NOCs, viz., OIL & ONGC, is being supplied predominantly to fertilizer plants, power plants, court-mandated customers, and customers having a requirement of less than 50,000 standard cubic metres per day at APM rates. The Government fixed APM gas price in the country, with effect from 1.6.2010, is \$ 4.2/mmbtu (inclusive of royalty), excepting in the Northeast, where the APM price is \$ 2.52/mmbtu, which is 60% of the APM price elsewhere, the balance 40% being paid to NOCs as subsidy from the Government Budget.

20.2.2 These gas-producing blocks were allotted to National Oil Companies on a nomination basis, under the tax-royalty regime. As most of the gas produced is going towards heavily subsidized sectors like fertilizer, power and small and medium buyers, the impact of price variations is borne by NOCs. However, NOCs producing such gas are deprived of increases in gas prices. This affects their investment in exploration and production.

20.2.3 Owing to existing supply linkages and operational requirements, it was decided to have a Gas Pool Account mechanism, with inflows coming from the sale of APM gas to consumers not entitled for APM gas at market price and outflows being for the purchase of non-APM gas to customers entitled for gas at APM price.

20.2.4 The price of APM gas supplied to customers not entitled for APM gas is being notified by the Ministry of Petroleum and Natural Gas from time to time. The market-driven price, effective from 1.7.2010, is as below:

<b>Area/Zone</b>	<b>Price (\$/mmbtu)</b>
Western & Northern Zones (covering Maharashtra, Gujarat and other States covered by HVJ/ DVPL, viz., Rajasthan, M.P., U.P., Haryana & Delhi)	5.25
Southern Zone -- KG Basin	4.5
Southern Zone -- Cauvery Basin	4.75
North-East	4.2
Identified onshore fields in Gujarat & Rajasthan	5.0

### **20.3 Non-APM Gas produced by NOCs from Nominated Fields**

20.3.1 National Oil Companies (NOCs), viz., ONGC & OIL, are in principle free to charge a market-determined price for gas produced from new fields in their existing nominated blocks. However, Government has issued a pricing schedule & guidelines for commercial utilization of non-APM gas produced by NOCs from their nominated blocks. Four supply zones have been identified in the guidelines and the prices of non-APM gas sold by NOCs in these zones are as follows:-

<b>Area/Zone</b>	<b>Price (\$/mmbtu)</b>
Western & Northern Zones	5
Southern Zone -- KG Basin	4.5
Southern Zone -- Cauvery Basin	4.75
North-East	4.2

20.3.2 Further, a premium of \$ 0.25/mmbtu for production of non-APM gas from offshore fields has been provided, as higher investment is required for development of and production from offshore fields. National Oil Companies suffer a loss of profitability for reasons similar to those discussed in respect of APM gas.

## **20.4 Pre-NELP Gas**

### **Pricing under Pre-NELP Discovered Fields**

20.4.1 Certain blocks where discoveries were made by NOCs were auctioned to private sector E&P companies to overcome funding constraints and lack of advanced technologies. Under these PSCs, viz., Panna-Mukta, Tapti (PMT) and Ravva, the gas produced has to be sold to the GOI nominee (viz., GAIL), as per the price formula specified in the PSC. Hence, the entire gas produced from these fields is being purchased by GAIL. The PSCs for Panna-Mukta & Tapti were executed on December 12, 1994 and that of Ravva on October 28, 1994. In case of Panna-Mukta & Tapti PSCs, the price formula for gas is linked with an internationally traded fuel oil basket, with a specified floor and ceiling price of US\$ 2.11/mmbtu and US\$ 3.11/mmbtu respectively. These PSCs further have a provision to revise the ceiling price after 7 years from the date of first supply, to 150% of 90% of the fuel oil basket (average of the preceding 18 months). With this revision, the revised ceiling price in case of Panna-Mukta gas is US\$ 5.73/mmbtu and in case of Tapti, it is US\$ 5.57/mmbtu. GAIL, as the Government nominee, is buying gas from the PMT JV at this rate. Out of the total allocation 17.3 mmscmd, 5 mmscmd of PMT gas has been allocated to power & fertilizers sectors, which is being supplied at the APM rate to consumers. The difference in price is recovered from the gas pool account.

20.4.2 As regards Ravva & Ravva satellite fields, under the provisions of their PSC, on expiry of five years from the date of first delivery of gas, the JV and the Government are required to enter into good-faith negotiations to determine the basis for calculation of the purchase price, taking into account all reasonably relevant factors. The present price of the Ravva field is US\$ 3.5/mmbtu and that of Ravva satellite is US\$ 4.3/mmbtu. Revision of the prices is due, and GAIL & the JV are in negotiations. The gas from Ravva field is being supplied at the APM rate to consumers and the difference in price is being recovered from the gas pool account.

## **20.5 Pricing under Small-sized Discovered Fields & Pre-NELP Exploratory Blocks**

20.5.1 24 small-sized discovered fields and 28 pre-NELP exploratory blocks (of which 17 are in operation) have been signed with private E&P companies (viz. Hazira, RJ-ON-90/1 etc.). These provide for the sale of gas in the domestic market at prices obtained as per the arms length principle, in case the gas is sold other than to the Government nominee. There is no price formula specified under the PSCs and the price formula does not require prior approval of the Government before sale of gas by the Contractor, unlike under NELP.

## **20.6 Pricing under NELP**

20.6.1 The Production Sharing Contracts (PSC) signed under New Exploration Licensing Policy (NELP) provide for approval of the price formula / basis by the Government, before the sale of natural gas by the Contractor. Under Article 21 of the PSC, the Contractor is required to sell the gas in the domestic market in accordance with the Gas Utilization Policy of the Government. Further, Article 21.6 of the PSC provides for sale of gas at competitive, arms length price, to the benefit of parties to the Contract and it also provides that the gas price formula/basis have approval of the Government prior to the sale of natural gas to consumers/buyers.

20.6.2 The following provisions of the PSC are relevant in the context of sale of natural gas and the price to be adopted for valuation purposes to calculate cost petroleum, profit petroleum share and royalty:

***"Article 1.8 "Arms Length Sales"*** means sales made freely in the open market, in freely convertible currencies, between willing and unrelated sellers and buyers and in which such buyers and sellers have no contractual or other relationship, directly or indirectly, or any common or joint interest as is reasonably likely to influence selling prices and shall, inter alia, exclude sales (whether direct or indirect, through brokers or otherwise) involving Affiliates, sales between Companies which are Parties to this Contract, sales between governments and government-owned entities, counter trades, restricted or distress sales, sales involving barter arrangements and generally any transactions motivated in whole or in part by considerations other than normal commercial practices.



**Articles 21.6 Valuation of Natural Gas**

21.6.1 The Contractor shall endeavour to sell all Natural Gas produced and saved from the Contract Area at arm's length prices to the benefits of Parties to the Contract.

21.6.2 Notwithstanding the provision of Article 21.6.1, Natural Gas produced from the Contract Area shall be valued for the purposes of this Contract as follows:

- (a) Gas which is used as per Article 21.2 or flared with the approval of the Government or re-injected or sold to the Government pursuant to Article 21.4.5 shall be ascribed a zero value;
- (b) Gas which is sold to the Government or any other Government nominee shall be valued at the prices actually obtained; and
- (c) Gas which is sold or disposed of otherwise than in accordance with paragraph (a) or (b) shall be valued on the basis of competitive arm's length sales in the region for similar sales under similar conditions.

21.6.3 The formula or basis on which the prices shall be determined pursuant to Article 21.6.2 (b) or (c) shall be approved by the Government prior to the sale of Natural Gas to consumers/buyers. For granting this approval, Government shall take into account the prevailing policy, if any, on pricing of Natural Gas, including any linkages with traded liquid fuels, and it may delegate or assign this function to a regulatory authority as and when such an authority is in existence.

20.7 From the above provisions, the following principles apply for approval of the price formula for valuation of natural gas:

- a) The valuation of gas sold to any party will be as per Article 21.6.2 (c), which provides that gas be valued on the basis of competitive arm's length sales in the region, for similar sales under similar conditions.
- b) As per Article 21.6.1, the Contractor shall endeavour to sell all natural gas produced and saved from the Contract Area at arm's length prices, to the benefit of the parties to the Contract.

- c) As per Article 21.6.3 of the PSC, the formula or the basis on which the prices shall be determined pursuant to Article 21.6.2 shall be approved by the Government prior to the sale of the natural gas to the consumers / buyers.

20.8 Under NELP, gas pricing has formally been approved only in case of RIL's KG Basin discovery. A proposal of RIL in 2006 to approve the price of US\$ 2.34/MMBTU, which was the contractual price with RNRL, was rejected by the Government on the ground that the price was not derived on the basis of competitive arm's length sales in the region for similar sales under similar conditions. Government of India set up a committee to arrive at valuation of natural gas when price discovery is not possible through market mechanism. The committee had extensive consultations with various stakeholders, including producer and consumer groups, besides expert agencies. The committee recommended, inter alia, the following:

- (a) In all situations where price discovery through competitive bidding is possible, there should be no need to apply any other principle for valuation of gas, and the Government should not interfere.
- (b) However, in the absence of market-determined price through a transparent bidding process, where valuation has to be necessarily done by the Government, it may be done based on the most recent, competitively determined price in the region duly indexed to the present. The indexation is to be done as per the provisions of market-determined contracts as each market-determined price has a contract which sets out various terms and conditions of supply, including the price-review mechanism.
- (c) Typically, all long-term gas contracts have a clause for periodic gas price review. The committee recommended that if price is reviewed as per the contract, that price may become the new reference price and, for the interim period, it may be linked to percentage increase in price of furnace oil. Furnace oil is not only the cheapest liquid fuel, but has shown the least price-volatility in recent years.
- (d) The committee further recommended that above valuation methodology may be applied in cases where actual supply has commenced but price could not be discovered through the market mechanism. However, if the actual price at which any producer

supplies to any consumer happens to be higher than the one arrived at by above methodology, then the higher price shall be reckoned for the Government take.

20.9 Subsequently, in May 2007, the Contractor of KG-DWN-98/3 block, viz., RIL, submitted a revised proposal of price formula/basis for approval by the Government. In the proposal, the price formula was benchmarked to international crude price, with a floor and a ceiling price, and also with a constant factor  $\text{C}$  to take care of bidding. The price formula proposed was as under:

$$\text{SP (Rs./mmbtu)} = 112.5 * K + (\text{CP}-25)^{0.15} * \text{ER} + \text{C}$$

Where

SP is the sale price of gas in Rs/mmbtu.

CP is the annual average Brent crude price for the previous financial year, with a cap of \$ 65/bbl and a floor of \$ 25/bbl.

ER is the average \$/Rs. exchange rate for the previous financial year.

K is 1 for ER between 25 and 65, or ER/25 when ER is less than 25 or ER/65 when ER is more than 65.

C is the premium quoted by the customer.

20.10 RIL, in its proposal, stated that bids were received from 10 customers (5 each from the power and fertilizer sectors), and based on the bids received, at a value of  $\text{C}=4$ , most of the gas stood picked up by the bidders.

20.11 The above price proposal was initially considered by the Economic Advisory Council to the Prime Minister (EAC), chaired by Dr Rangarajan, which examined the pricing formula and made important recommendations. The Government also constituted a Committee of Secretaries (COS) under the Cabinet Secretary to consider the gas supply and pricing issues. This committee recommended that the Government may consider framing a Gas Pricing and Gas Utilization Policy, before considering the price proposal. Submissions made by various stakeholders which were taken into account by both these committees while giving their report. Finally, the matter was considered by an Empowered Group of Ministers (EGoM), headed by the then Minister for External Affairs, Shri Pranab Mukherjee, constituted on 13<sup>th</sup> August 2007 to examine and decide issues relating to gas pricing and commercial utilization of gas under the New Exploration & Licensing Policy (NELP). The EGoM, after

taking into account the reports submitted by the said two committees and representations made by various stakeholders, at its meeting held on 12<sup>th</sup> September 2007, recommended the following:

- (a) The price basis / formula submitted by M/s. Reliance Industries Limited (RIL) and Niko Resources Limited (NRL), may be accepted with modifications as per the recommendations of the EAC, including denomination of the entire formula in US dollars. For all NELP-I to NELP-VI contracts, for natural gas price calculation, the constant will be pegged at US \$ 2.50/mmbtu. The EGoM observed that since  $\text{£q}$  was the only biddable component in the formula submitted, assigning a value of zero to this would address the transparency aspect of the bidding process. In this context, it may be relevant to mention that M/s. RIL had proposed the value of  $\text{£q}$  at Rs. 4/mmbtu whereas fertilizer units had bid low at Rs. 1/mmbtu for  $\text{£q}$ .
- (b) The cap for the price of crude oil in the variable portion of the formula would be frozen at US\$ 60/barrel, instead of US\$ 65/barrel, as proposed by M/s. RIL-NRL. This would, in turn, translate into a lower consumer price by reduction in the ceiling of the crude price.
- (c) This price basis / formula will be valid for five years from the date of commencement of first commercial production and supply.
- (d) The price discovery process on arms length basis will be adopted in future NELP contracts only after the approval of the price basis / formula by the Government. The price discovered through this process would be applicable uniformly to all sectors.
- (e) The decisions taken at the EGoM meeting will be without prejudice to the NTPC vs. RIL and RNRL vs. RIL Court cases, which are at present sub-judice.

The price formula finally approved by the EGoM was as under:

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

Where,

SP is the sales price in \$/mmbtu (on Net Heating Value / NHV basis) at the delivery point at Kakinada.

CP is the average price of Brent crude oil in US\$/barrel for the previous financial year, based on the annual average of the daily high and low quotations of the FOB price of dated Brent quotations as published by Platts Crude Oil Marketwire. CP is capped at US \$ 60/bbl, with a floor of US\$ 25/bbl. CP is fixed for each contract year and is based on the CP for the preceding financial year.

FY means the financial year, which commences each year on 1<sup>st</sup> April and ends on the following 31<sup>st</sup> March.

20.12 The selling price comes to US\$ 4.2/mmbtu for crude price greater than or equal to US\$ 60/barrel. This is equivalent to Rs. 7,500/mscm at an exchange rate of US\$ 1 = Rs. 45. The price basis/formula is valid for five years from the date of commencement of supply, i.e., till March 2014.

20.13 Important features of the formula approved are:

- (i) Setting a floor for the gas price, to ensure that the Contractor is able to recover the cost of production;
- (ii) Dampening the volatility in prices by raising the upswing in crude prices to 0.15; and
- (iii) Fixing a ceiling of \$ 60/bbl of crude price to ensure that speculative increase in crude price does not impact the competitiveness of Indian industry.

#### **20.14 Regasified LNG (RLNG):**

##### **Sources of RLNG in India**

20.14.1 At present, RLNG is imported by Petronet LNG Limited (PLL), Gujarat State Petroleum Corporation (GSPC), GAIL and Hazira LNG Private Limited (HLPL) from countries such as Qatar, Oman, Nigeria, Norway, Malaysia, Trinidad & Tobago, Egypt, Algeria etc. During 2011-12, such imports were as under:

Company	Quantity (million metric tonnes)	Country/Source
Petronet LNG Ltd. (PLL)	9.350	Qatar, Oman, Nigeria, Norway, Malaysia, Trinidad & Tobago
GSPC	0.561	Australia, USA, Egypt, Nigeria, Qatar
GAIL	0.900	Oman, Egypt, Qatar, Nigeria, Algeria, Trinidad & Tobago
HLPL (Shell)	2.532	Nigeria, Qatar, Yemen, Egypt, Abu Dhabi
<b>Total</b>	<b>13.343</b>	

### 20.15 Qatar Gas:

20.15.1 A contract was signed with RasGas, Qatar for supply of 7.5 mmtpa LNG (equivalent to about 28 mmscmd) by Petronet LNG Limited (PLL). Supply of 5 mmtpa commenced from April 2004, while supply of the remaining 2.5 mmtpa commenced in January 2010. The price for LNG has been linked to JCC (Japanese Custom Cleared) crude oil under an agreed formula. The long-term RLNG price changes every month. The formula agreed between PLL & RasGas, Qatar for import of term LNG is as follows:

$$\text{FOB} = P_o * \text{JCC}_t / \$15$$

Where:

$P_o = \$ 1.90/\text{mmbtu}$

JCC<sub>t</sub> is the 12 month\$ average of the JCC price

t is the month for which price is being calculated

JCC<sub>t</sub> shall have following floor and cap:

Cap =  $[(60 - N)*20 + (N*A_{60})]/60 + 4$

Floor =  $[(60 - N)*20 + (N*A_{60})]/60 - 4$

Where N = 1 for January 2009, and increases by 1 every month thereafter, till December 2013, after which it shall remain 60.

$A_{60}$  = 60 month\$ average of the JCC price

20.15.2 The liquefaction cost is in-built in the above price. There is no separate cost for liquefaction. Other relevant costs are the costs of shipping, insurance, freight and regasification. The average cost of these components is as under:

- Shipping cost is dependent on distance. For Qatar and India, it is \$ 0.30/mmbtu. Import duty is 5.15%.
- Insurance cost is negligible, at around \$ .0025/mmbtu.
- Regasification cost: The cost of installing a regasification plant is US\$ 1 billion with a capacity to produce 5 mmtpa of gas. The cost of regasification charged from the customers is a negotiated charge and is in the range of \$ 0.70/mmbtu. The price of RLNG applicable for the month of June 2012 is as under:

	<b>\$/mmbtu</b>
FOB price	- 9.00
Shipping cost	- 0.30
Insurance	- 0.0017
Total	- 9.3017
Custom duty	- 0.50
Regasification cost	- 0.64
<b>Total Cost</b>	<b>10.44</b>

## 20.16 Gorgon Gas:

20.16.1 PLL has signed another contract with EXXON-MOBIL for import of 1.44 mmtpa of LNG from its Gorgon venture in Australia. The project is scheduled to be commissioned at the beginning of 2015. The price formula under this contract is linked with JCC as under:

$$\text{FOB} = 14.5\% * \text{JCC}$$

The FOB cost includes liquefaction cost. Transportation cost is \$ 0.75/mmbtu for shipping from Australia. Other costs are the same as in the case of Qatar gas. At a JCC price of \$ 80/bbl, the average cost of gas shall be as under:

	<b>\$/mmbtu</b>
FOB Price	- 11.60
Shipping cost	- 0.75
Insurance	- 0.0017

Total	-	12.3517
Custom duty	-	0.636
Re-gasification cost-		0.64
<b>Total Cost</b>		<b>13.6277</b>



## **21 International Gas Pricing**

### **21.1 Systems of Gas Pricing Mechanism**

21.1.1 As per International Gas Union (IGU) Whole Sale Gas Price Formation June-2011 Report, prevailing prices of gas can be categorised into the following:

- “ Gas-on-gas competition
- “ Oil price escalation
- “ Bilateral monopoly
- “ Netback from final product
- “ Regulation on a cost-of-service basis
- “ Regulation on a social and political basis
- “ Regulation below cost
- “ No pricing

### **21.2 Gas-on-gas competition**

21.2.1 Gas-on-gas competition is the dominant pricing mechanism in the US and the UK. It means that the gas price is determined by the interplay of gas supply and demand over a variety of different periods (daily, weekly, monthly, quarterly, seasonally, annually or longer). Trading takes place at physical hubs, such as Henry Hub, or notional hubs, such as the National Balancing Point (NBP) in the UK. Trading is likely to be supported by developed futures markets (such as New York Mercantile Exchange or Intercontinental Exchange) and online commodity exchanges (Intercontinental Exchange or Online Capital Markets Limited). Not all gas is bought and sold on a short-term, fixed price basis . there are longer term contracts too, but these rely on gas price indices rather than competing fuel indices for, e.g., monthly price determination. Gas-on-gas competition does not mean that competing fuel prices play no role in determining the gas price. Key groups of gas consumers can switch between gas and oil products, or between gas and coal, in response to price signals. This substitutability of gas means that the prices of gas oil, Heavy Furnace Oil (HFO) and . at the low-end . coal typically frame the range within which gas prices may move. However, this

market link (as opposed to contractual link) between the prices of different fuels is neither stable over time and nor is it able to prevent the movement of gas prices outside their prescribed corridor for long periods of time.

### **21.3 Oil price escalation**

21.3.1 Oil price escalation is the dominant pricing mechanism in Continental Europe and Asia. It means that gas price is contractually linked, usually through a base price and an escalation clause, to the price(s) of one or more competing fuels, the linked competing fuel in Europe typically being gas oil and/or fuel oil, and that in Asia typically being crude oil. Occasionally, coal prices too are part of the escalation clause, as are electricity prices. The escalation clause ensures that when an escalator value changes, the gas price is adjusted by a fraction of the escalator value change, depending on a so-called pass-through factor. In addition to the link to the prices of competing fuels, it is common to include a link to inflation in the escalation clause. Oil price escalation does not mean that gas supply and demand play no role in determining the gas price. If Continental European or Asian buyers see the oil-linked prices they pay for long-term gas or LNG falling out of line with the supply and demand-driven prices on the gas exchanges that are emerging, or on the global spot LNG market, customers will switch to short-term gas to the extent they can, with contract price adjustments as a possible result.

(Source: International Gas Union's Wholesale Gas Price Formation June-2011 Report)

### **21.4 Bilateral monopoly**

21.4.1 Bilateral monopoly negotiations were the dominant pricing mechanism in interstate gas dealings in the former Eastern Blocq including the former Soviet Union (FSU) and Central and Eastern Europe. Gas price was determined for a period of time . typically one year . through bilateral negotiations at the government level. There were often elements of barter, with buyers paying for portions of their gas supply in transit services or by participating in field development and pipeline building projects. The underlying valuation of the gas, the capital goods and the services that changed hands in the intra-Eastern Blocq gas trade was opaque, with politics playing a major role alongside economics. Examples of gas pricing based on bilateral negotiations may still be found in countries where one dominant supplier, e.g., the national oil company, faces one

or a couple of dominant buyers, say, the state owned power company and maybe one or two large industrial companies. A number of immature developing country gas markets have this structure.

(Source: International Gas Union's Wholesale Gas Price Formation June-2011 Report)

## **21.5 Netback from final product**

21.5.1 Netback from final product means that the price received by the gas supplier reflects the price received by the buyer for his final product. For instance, the price received by the gas supplier from the power sector may be set in relation to, and allowed to fluctuate with, the price of electricity. Netback based pricing is also common where the gas is used as a feedstock for chemical production, such as ammonia or methanol, and represents the major variable cost in producing the product.

(Source: International Gas Union's Wholesale Gas Price Formation June-2011 Report)

## **21.6 Regulation on a cost-of-service basis**

21.6.1 Under cost-of-service based regulation the price is determined or approved by a regulatory authority, or a Ministry, so as to cover the ~~cost~~ cost of service~~+~~, including the recovery of investment and a reasonable rate of return, in the same way as pipeline service tariffs are regulated in the US. Normally, cost-of-service based prices are published by the regulatory authority. Pakistan provides an example of cost-of-service based prices, with the wellhead price being the target.

(Source: International Gas Union's Wholesale Gas Price Formation June-2011 Report)

## **21.7 Regulation on a social and political basis**

21.7.1 Prices may also be regulated on an irregular social and political basis, reflecting the regulator's perceptions of social needs and/or gas supply cost developments, or possibly as a revenue-raising exercise for the Government. In all probability, the gas company would be state-owned.

(Source: International Gas Union's Wholesale Gas Price Formation June-2011 Report)

## **21.8 Regulation below cost**

21.8.1 Many non-OECD countries still practice below-cost regulation, meaning that the gas price is knowingly set below the sum of production and transportation costs as a form of state subsidy to the population. Again, the gas company would be state-owned.

(Source: International Gas Union's Wholesale Gas Price Formation June-2011 Report)

## **21.9 No pricing**

21.9.1 In some countries where a substantial proportion of indigenous gas supply comes from oil fields with gas caps or gas-condensate fields, the marginal cost of producing such gas may be close to zero and, as such, it could be sold at a very low wholesale price and still be profitable. However, to the extent it is sold below the average cost of production and transportation it would still be included in the regulation below cost category. An extreme form of below-cost regulation is to provide the gas free-of-charge to the population and the industry, e.g., as a feedstock for chemical and fertilizer plants. Free gas is typically associated gas treated as a by-product with the liquids covering the costs of bringing the gas to the wellhead. The gas supplier must somehow finance transportation and distribution costs, cross-subsidising local gas supply from his oil or gas export revenues, or the Government must provide funding from its budget.

(Source: International Gas Union's Wholesale Gas Price Formation June-2011 Report)

**22**

## **Pricing Formations Prevalent in Various Countries**

22.1 Natural gas markets are evolving differently in important geographical markets. There is no single global market for natural gas. This can be due to difficulties in large-scale transportation over long distances. As technologies evolve, it is likely that these regional markets get integrated. Major regional markets for natural gas are the US, continental Europe, the UK, countries that were once a part of the former Soviet Union (FSU), the Asia-Pacific and the Middle East. Each of these markets has its own supply-demand dynamics. The subject merits a brief discussion as it provides valuable inputs for pricing policy in India.

22.2 **North America:** Rapid expansion of the pipeline network and well-head price regulation characterized two decades of rapid growth after the Second World War. While inter-state trades were governed by regulation, intra-state gas market was mostly deregulated. Later, even inter-state trading was regulated on a cost-plus pricing basis, leading to severe shortages in importing states. During the mid-eighties, the gas market was totally deregulated, allowing customers to directly contract purchases with the producers. These regulatory measures created a highly vibrant gas market in the US, which operated through various hubs. Trading in both physical and paper forms happens at these hubs and most of them are now linked to Henry Hub (located near the Mexican Gulf), which is the most liquid market. Henry Hub is also the reference for New York Mercantile Exchange Futures. It is also noted that deregulation in the US happened over a period of three decades and was facilitated by substantial domestic production, saturation coverage of the country by a pipeline network, and other infrastructure, including LNG plants.

22.3 **UK:** Till 1986, British Gas Corporation was the sole buyer, transmitter and distributor of gas in the UK. It also had substantial upstream business. Thus it was able to negotiate a favourable price using its monopoly status and knowledge of upstream cost. The monopoly of British Gas was slowly diluted during the eighties, and in the nineties regulations allowed customers to directly

buy gas from producers, bypassing British Gas. This paved the way for the wholesale gas market hub, called the National Balancing Point, which is the most liquid and mature gas market in Europe. The UK gas market is connected to Continental Europe through two gas lines.

## **Continental Europe**

22.4 Initial development of the European market was solely the handiwork of the Dutch Government, which was trying to market Groningen gas. They developed the netback-from-consumer method, in place of cost-plus pricing for natural gas. They also initiated the replacement-fuel-value principle in several long-term contracts with Germany, as gas was replacing HFO and gas oil. These two principles governed European market till the nineties, when the development of spot gas markets began in a modest fashion. This was brought about mainly by liquidity generated by NBP through its physical connection with Europe and development of several hubs like TTF, Zeebrugge, PEG NORD, NCG and GPL. By 2009, these hubs significantly improved liquidity in Europe and made gas-on-gas price formation a reality in Europe.

22.5 The other dominant index in Europe is the German Border Price [Source : *'Natural Gas Pricing and it's Future : Europe as the Battleground'* (Page 31)], which is an average of the oil-indexed contracts that comprise 90% of German gas supplies and spot supplies at hub prices. As the spot market develops further, most of the German contracts are getting partially indexed to hub prices.

22.6 Continental European buyers have signed medium/long-term contracts for an estimated 350 billion cubic metres of gas a year, and although a high share of these contracts presently are of the standard oil-linked type, annual commitments will start declining from around 2015.

22.7 In 2008, existing medium/long-term contracts corresponded to more than 80% of Continental Europe's gas consumption (with the rest being short-term purchases). Going forward, this share will, of course, decline. In line with the average annual growth rate between 1987 and 2007, the contracted supply will meet around two-thirds of Continental Europe's gas demand by 2015 and less than a quarter of the demand by 2025.

22.8 There is a definite trend among gas-sellers and buyers to get rid of the oil-link, and incumbents on both sides of the table seem to be slowly dispensing with oil indexation.

### **Former Soviet Union (FSU)**

22.9 FSU countries have to rely on Russian gas and have had to take major price adjustments. More recently, FSU countries had to cope up with sea changes in the pricing of Russian gas, although different countries have been granted different transition periods and were paying significantly different prices in 2008.

22.10 The Russian-Ukrainian dispute over gas prices, transit tariffs and payment arrears has received special attention in the past due to Ukraine's role as a transit country for nearly two-thirds of Russia's gas exports to Europe. The financial stand-off between Russia and Ukraine has lowered Russia's oil-linked export prices.

22.11 Russia's gas company, Gazprom continues to adjust existing agreements with FSU countries step-by-step, in order to move to contractual terms and conditions and pricing mechanisms similar to those effective in the European countries beginning from 2011.

22.12 The Central Asian Republics have been aggressively pricing their gas sales to Russia. Back in 2000, Gazprom typically paid a border price of around US\$ 1.10/mmbtu for Turkmeni and other Central Asian gas. In the first half of 2008, Turkmenistan received US\$ 3.59/mmbtu for its gas. At the same time, the heads of Turkmenistan's, Kazakhstan's and Uzbekistan's state oil and gas companies announced that from 2009 on Gazprom would need to pay the price of gas on Europe's Eastern border, netted back to the delivery points for Central Asian gas on Russia's Southern border.

### **Asia-Pacific**

22.13 The Asia-Pacific gas market is dominated by Japan, which has a 33% share of the global LNG market. Japanese power companies rely mainly on oil as their fuel. Natural gas replaces oil in power generation, fuel oil in industries,

and kerosene for heating. Hence Japanese buyers agreed readily for oil indexation. Currently, most of Japanese Contracts are weighted average price of oil imported into Japan (JCC) as the index. The price formula generally followed is.

$$SP = A * (JCC/Barrel) + B$$

Bqsets the floor price to ensure break-even for producers and suppliers in case of oil price collapse. Aqby reducing JCC to 80 to 90% reduces volatility. The upsurge in oil prices and recession in the world economy are forcing Japan to delink gas prices from oil indexation and seek fairer, market-determined pricing. It is likely that Japan may transit into indexation to hub prices of the US and the UK over the next few years.

22.14 Other countries in the region, like Indonesia, Malaysia and Australia, export their production on oil-price-indexed contracts to Japan and other countries of the region.

22.15 **China:** China is not one integrated gas market. China has multiple regional markets that have traditionally received supply from different production areas at different costs, and with different prices as a result. These characteristics are gradually giving way to those of a more integrated market. Rapid construction of new long-distance pipelines will give sellers access to a bigger variety of buyers, and the buyers access to a bigger range of sellers. In China, as in other centrally planned economies, gas prices were historically used for accounting purposes rather than for resource allocation. Gas produced under the national plan was priced differently from the gas produced outside the national plan. End-user prices differed not only by region but also by consumption sector; thus the fertilizer industry paid less than other industry. Neither the complexity, nor the rigidity of the gas price structure, nor the fact that many prices did not cover supply costs, encouraged gas exploration and development. On the other hand, gas was much more expensive in energy equivalence terms than coal. This prevented gas penetration into the power sector and other sectors where coal was an option. Cost-plus pricing is still the rule, although procedures are being streamlined and standardised. Also, an element of competitive pricing has been introduced. Wholesale buyers are allowed to negotiate directly with suppliers. Currently, ex plant prices are set by



China's National Development and Reform Commission (NDRC). Suppliers and purchasers of the ex plant natural gas may negotiate a purchase and sale price no higher than 10 per cent of the guide price (or any price lower than the NDRC guide price). The ex plant prices are adjusted annually, and the adjustment factors take into account the average prices of crude oil, liquefied petroleum gas (LPG) and coal in the last five years, with a weighted percentage of 40 per cent for crude oil, 20 per cent for LPG, and 40 per cent for coal. Any year-on-year adjustment should not be more than 8 per cent. The ex plant prices are set according to usage: thus natural gas is to be used for fertilizer plants, direct industrial customers, and city gas. In late December 2011, the NDRC issued a notice announcing a natural gas price reform pilot scheme. According to the notice, the pilot scheme will be implemented in Guangdong province and the Guangxi Autonomous Region. The pricing mechanism is to be changed from a %production cost+ base to a %market net return+ base. The new pricing mechanism applies to gas produced at onshore gas fields in China and imported pipeline gas. The new city-gate prices will be linked to the import price of two types of substitute fuels: fuel oil (given a 60 per cent weight in the final prices) for power generation, and LPG (having a 40 per cent weight in the final prices) for cooking in Shanghai, and the prices of these substitute fuels are to be used as a starting point by the government to derive a benchmark price in Shanghai. This benchmark price will, in turn, be used to calculate gas prices for Guangdong and Guangxi, which are the two regions initially subject to the scheme. The city-gate prices are adjusted, initially annually, then semi-annually or quarterly, according to the change in prices for the aforementioned substitute fuels.

(Source: International Gas Union's report on Wholesale Gas Price Formation June-2011 Report)

## Latin America

22.16 In Latin America, cost-based pricing was the rule until the early 1990s.

22.17 **Argentina:** Argentina, in the early 1990s, de-controlled wellhead prices, with the regulator (Enargas) continuing to regulate transmission and distribution tariffs. These were originally set to ensure a fair return on investments in pipelines and other facilities, but emergency legislation passed in the wake of Argentina's economic crisis in the early 2000s authorised the government to re-impose price and exchange controls, with the result that tariffs and prices in dollar terms dropped significantly. In 2004, Argentinean authorities and the

country's main gas producers agreed on a schedule for partially lifting the price freeze, but progress has been limited, although more recently producers and large industrial and power sector end-users have been free to negotiate prices. Producers receive only about US\$ 1.50/mmbtu for indigenous gas. This low price reflects decisions made in the wake of the Argentinean economic crisis at the turn of the century. It is about one-fifth of what Argentina pays for Bolivian gas and is not encouraging gas exploration and development, which is one reason why Argentinean gas production has stagnated and shortages have emerged. In March 2008, the Government authorised higher prices for gas produced from new, remote or tight fields with above-normal development costs. But this so-called *gas-plus* plan does not introduce new pricing principles; it only amounts to a modernisation of the cost-plus approach.

(Source: International Gas Union's Wholesale Gas Price Formation June-2011 Report)

**22.18 Brazil:** Brazil, in 2002, liberalised gas prices but continues to regulate prices to qualifying gas power plants. Regulator (National Agency of Petroleum, Natural Gas and Biofuels, or Agência Nacional do Petróleo, Gás Natural e Biocombustíveis . ANP) sets transportation tariffs on a cost-of-service basis. Petrobras's dominating role in the upstream and continued hold on the transmission link limits the role of competition in gas price formation, with wholesale gas prices now increasingly following oil prices. Gas prices in nominal US\$ terms increased significantly in 2003 and again in 2005. The price of locally produced gas jumped from about US\$ 3/mmbtu by mid-2004 to US\$ 10/mmbtu by late 2008.

(Source: International Gas Union's Wholesale Gas Price Formation June-2011 Report)

**22.19 Venezuela:** In Venezuela, private producers have been allowed since 2001 to sell gas directly to end-users, bypassing Petróleos de Venezuela (Petroleum of Venezuela) S.A. or PdVSA, the Venezuelan state-owned oil and natural gas company. But because of limited access to PdVSA's pipelines, the state company remains the main market for private gas. Moreover, the Ministry of Energy and Petroleum caps prices at levels supposedly reflecting Anaco or Lake Maracaibo hub costs and transportation costs but clearly reflecting other, political and social considerations as well. As importantly, maximum prices are quoted in Bolivars, and provisions exist for adjusting them in response to inflation and changes in the exchange rate.

(Source: International Gas Union's Wholesale Gas Price Formation June-2011 Report)

## Gulf Countries

22.20 **Iran:** Iran began harnessing associated gas in the 1960s, and Saudi Arabia followed suit with the construction of the Master Gas System in the late 1970s. Both these countries, and eventually others in the region, funded gas infrastructure investments from their oil export revenues. The rulers' main motivation was to contain the growth in domestic oil consumption. This could have been done in different ways, probably most efficiently by raising domestic oil product prices. Oil price reform could, however, have triggered political and social unrest. Positive price and availability incentives to switch to gas appeared much safer. Though Iranian gas use (net of reinjection) increased by 10.5% a year between 1991 and 2006, domestic oil consumption growth continued to outpace oil production growth. The country's position as a major oil exporter came under increasing pressure. Therefore, since the 1990s, Iranian rulers have intensified efforts to make fuel users switch from oil products to gas, by providing for continuous growth in the gas grid and keeping domestic gas prices at very low levels.

(Source: International Gas Union's Wholesale Gas Price Formation June-2011 Report)

22.21 **Saudi Arabia:** Saudi Arabia too has maintained domestic gas price at a very low level for a very long time. Between 2001 and 2008, no material adjustments have taken place. Saudi Arabia has come under pressure internationally for its highly subsidized prices. Trade partners have protested that the country, now a full member of the WTO, is unfairly supporting Saudi industries and utilities. In an attempt to address the main distortions in the domestic gas sector, Saudi Arabia recently adopted a new pricing policy that could herald real price reform. In 2006, the local Eastern Gas Company was awarded a two-year contract to become Aramco's gas distributor to consumers in the Dhahran industrial area.

22.22 According to industry reports, its purchase price from Aramco will be US\$ 1.12/mmbtu and its sale price US\$ 1.34/mmbtu. In Riyadh, the Natural Gas Distribution Company was granted a license to supply small-scale manufacturing plants under a similar pricing structure. For the time being, the price for foreign investors and other consumers remains unchanged.

(Source: International Gas Union's Wholesale Gas Price Formation June-2011 Report)

## Africa

22.23 In **Algeria** and **Libya**, Sonatrach and National Oil Corporation respectively provide gas to big industrial and power sector customers at prices that are not publicly available but which apparently are low by international standards. Algeria also has a significant number of smaller scale, residential and commercial customers, and in 2006 Sonelgaz, a state-owned utility in charge of electricity and gas distribution in Algeria, supplied these customers at a fraction of what Mediterranean European residential and commercial gas consumers pay. In Egypt, Egypt's state-owned Egyptian Natural Gas Holding Company (EGAS) purchases gas from various upstream consortia at a price linked to oil but until recently capped at a low oil price; for the 2006 licensing round EGAS put the maximum gas price at US\$ 2.57 per thousand cubic feet for oil prices at or above US\$ 22/bbl. However, warnings from key upstream players that EGAS needed to pay more to enable companies to cover escalating costs and sustain exploration and development in 2007 brought results with British Petroleum and RWE (a German electricity and gas utility company) managing to negotiate a ceiling of US\$ 4.84 per thousand cubic feet. At the same time, hikes in select end-user gas prices were announced, reflecting government worries about its fuel subsidy burden as well as the sustainability of the pace of growth of domestic gas use. In **Nigeria**, as yet the only significant gas producer south of the Sahara, select industrial customers reportedly pay prices that cover supply costs, but the country's biggest gas user, the state power utility PHCN, reportedly paid only 11 US cents per mmbtu in 2005.

(Source: International Gas Union's Wholesale Gas Price Formation June-2011 Report)

22.24 **South Africa:** The price of natural gas is regulated by the National Energy Regulator of South Africa. The maximum prices of gas in South Africa, proposed by an applicant or licensee, are reviewed for purposes of approval by the Energy Regulator, based on the following formula:

$$GE = w1 CL + w2 DE + w3 EL + w4 HFO + w5 LPG$$

where:

**GE** = Maximum price for gas energy (ZAR/GJ) at the point of its first entry into the piped-gas transmission/distribution system;

**CL** = indicator of equivalent price of coal;

**DE** = indicator of equivalent price of diesel;  
**EL** = indicator of equivalent price of electricity;  
**HFO** = indicator of equivalent price of heavy fuel oil;  
**LPG** = indicator of equivalent price of liquefied petroleum gas;  
**wn** = weighting of the 'n<sup>th</sup>' indicator in the basket (where,  $w_1 + w_2 + w_3 + w_4 + w_5 = 100\%$ ).

22.25 The Energy Regulator determines these weights by using the total South African secondary energy sources (i.e., excluding the volume of coal used by Eskom for electricity generation). The South African Department of Energy's latest annual publication of *The Digest of South African Energy Statistics* is used to determine the relative weights of consumption of these individual energy indicators as a share of total consumption.

(Source: 1. National Energy Regulator South Africa (NERSA) Methodology to Approve Maximum Prices of Piped-Gas in South Africa October-2011

2. IGU's Report on Wholesale Gas Price Formation . A Global Review of Drivers and Regional Trends)

## **23 Stakeholder Views on Gas Pricing**

23.1 The Association of Oil & Gas Operators (AOGO) stated that the arm's length based gas price discovery, as provided for in the PSC, should be the basis. Government need to align the Gas Utilization Policy with its commitment given under the PSCs for free arm's length pricing. Differentiated policies for oil and gas should be done away with and sub-market pricing encourages inefficient consumption and shift of E&P investment outside India.

23.2 British Petroleum (BP) highlighted that arm's length, market determined pricing is mutually beneficial and market linked price results in increased government take. It was further stated that a substitute liquid fuel linked price is the best proxy for a gas market price. It enables immediate development of around 10 trillion cubic feet of discovered gas and creates the right economic climate to encourage investment in E&P sector. It ensures platform to transition to gas-on-gas competition.

23.3 CII highlighted that domestic gas prices have stayed constant for last four years making deep-water exploration unviable at current input costs.

23.4 GEECL stated that it does not have any major contract issues with the Government in CBM contracts.

23.5 FICCI recommended price discovery through a competitive, transparent bidding process by the Contractors. The price discovery process should be independent of the Government's policy for allocation and utilization of natural gas. All categories of buyers of natural gas should participate in the price discovery process. Access to natural gas may be allowed to all sectors. Sale of natural gas to constituents of the contractors or any of their affiliates should be allowed only at discovered arm's length price.

23.6 HOEC suggested that as per the PSC, arm's length based gas price discovery process may be pursued to determine price of domestic gas. A uniform transparent competitive bidding process may be followed to establish arm's length

price. Guidelines for the uniform bidding process may be framed by an independent, international advisory firm with experience in gas pricing and trading.

23.7 RIL presented that since 1991, market price for gas has been the cardinal principle for all PSCs. Various committees have recommended pricing of natural gas based on fuel oil parity, including for APM gas. Marketing freedom and market determined pricing are fundamental to NELP PSCs. Transparent price discovery is the preferred method for determination of arm's length price under the PSC. However, the Gas Utilization Policy precludes transparent market price discovery, as it restricts marketing freedom, necessitating a normative approach based on import parity. RIL proposed import parity pricing on the same principles as adopted for crude under the PSC and petroleum products generally.

23.8 Reliance Power presented its view on market-determined price for domestically produced gas from blocks awarded under NELP. It stated that market price of gas in India can be linked to price of imported LNG excluding the cost of components in the liquefaction price which are not incurred in production of domestic gas. It also proposed that a certain proportion of domestic gas be sold through competitive bidding.

## 24

## Recommendations on ToR (v)

### 24.1 Relevance of Different Price Formations

24.1.1 Gas pricing mechanism in India is presently driven by sectoral prioritization, administered gas allocation and pricing, apart from huge supply-side constraints. While short-term demand changes in international demand due to weather-related causes are quite frequent, the Indian gas market has not seen such volatility in demand in the short-term. This is mainly due to the fact that gas consumption is concentrated in the fertilizer, power and LPG sectors. Other factors resulting in short-term volatility, like business cycles and supply interruptions are also not relevant here. However, all these factors impact international gas price in the spot market and may impact profitability of Indian industry substantially.

24.1.2 Public sector companies producing gas have a highly regulated pricing system in place. Gas prices in India can, in principle, incentivize investment in the Indian upstream sector, so that production in India reaches optimum levels and all exploitable reserves put to production expeditiously. India also needs to ensure that producers don't cartelise as there is a huge unmet demand. The twin objectives of expediting production and avoiding cartelisation can be achieved by ensuring that producers in India get at least the average price of what producers elsewhere are getting.

24.1.3 Long-term prices in competitive markets in the US, the UK, continental Europe and the Asia-Pacific depend on the marginal supply cost curve, the efficiency of monetization of reserves, demand side factors like economic growth, energy intensity of major countries, ability of consumers to switch between fuels, and technological progress. However, there is no global competitive gas market. There are several regional markets in operation, all of which are heavily constrained by infrastructural, tariff and policy barriers.

24.1.4 An attempt is made below to contextualize internationally prevalent gas pricing mechanisms to the Indian market.



24.1.4.1 Gas-on-gas competition is the soundest of all mechanisms when free trade prevails in the gas market. The supply side in India is dominated by two large players, NOCs and RIL. Together they control the entire domestic production. RLNG supplies are again dominated by two entities, PLL and GAIL. The greatest constraint, however, is the lack of infrastructure for importing gas. All these result in a seller's market, with pricing power, which can lead to undue benefits. The consumption side is again dominated by PSU fertilizer units and power sector utilities, which are heavily subsidized by the Union and State Governments. Further, both these sectors have been encouraged through state policy to adopt gas-based technologies and they constitute a huge stranded market vulnerable to exploitation by gas suppliers. Thus, the supply curve at present is almost vertical and demand is highly price inelastic. Therefore, pure gas-on-gas competition will remain an aspiration till supply constraints are remedied substantially.

However, there are suggestions from several market players that sector-wise price discovery may still be possible in India. This idea merits a brief elaboration. Government of India has prioritized fertilizer, LPG, power and city gas distribution sectors for gas allocation. Proponents of this limited gas-on-gas competition model suggest that entities in each of these sectors can compete among themselves for allocation on price basis. Any such process will have two stages: the first stage being allocation of gas produced from the field to different sectors as per the Gas Utilization Policy (GUP), and the second being sector-wise price discovery of gas. For example, if a certain portion of the gas produced from a field is being allocated to the urea producing plants, the producer is supposed to invite bids from all urea producing plants ready to produce urea as on date of gas supply commencement and discover the market price on market-clearing basis and the bids received. All bids from related parties need to be discarded. This has to be repeated for all the sectors. However, this approach may result in two scenarios. In the first scenario, the demand in a particular sector may be high due to investments getting locked into gas-based technology. In such a scenario, price discovery may result in driving up prices to unviable levels. In the second scenario, consumers may cartelise to drive down prices. The process is likely to get deadlocked unless a very elaborate mechanism with checks and balances is set up.

Gas-on-gas competition for price discovery will become feasible once import infrastructure is ramped up and domestic production and transportation infrastructure grow. Therefore, Government may consider reviewing the situation after five years to examine the feasibility of its introduction.

24.1.4.2 Oil price escalation is one of the mechanisms suggested by several stakeholders. This is also in operation in a few long-term contracts for import to India. An EGoM has already approved one such formula for the gas produced in KG Basin by a consortium of RIL, NIKO and British Petroleum. All formulae have a base price for crude, a ceiling, and a factor to dampen volatility. The main reason for adoption of oil price escalation formula in the Asia-Pacific and in continental Europe is that gas replaces oil as fuel for domestic and industrial purposes. The share of gas sold globally under an oil price escalation formula is gradually coming down, from 22% in 2005 to 20% in 2007. For indigenous production, such a linkage is available in only 5% of the 2,048 billion cubic metres of gas produced globally in 2007.

24.1.5 Domestic production, consumed in the country of production, accounted for approx. 2,000 billion cubic metres in 2005, around 70% of total world consumption. The two largest price formation categories were gas-on-gas and regulation below cost, with gas-on-gas accounting for approx. 35% of world consumption (mainly in North America, the UK and Australia) and the regulation below cost accounting for 34% of world consumption (mainly in the former Soviet Union, the Middle East and Africa). Regulation on social and political basis, at 16% of world consumption, is spread across all regions. Regulation on cost of-service basis, at 4% of world consumption, is principally in Africa and Asia, while bilateral monopoly pricing at 5% of world consumption is mainly in the former Soviet Union and the Asia-Pacific.

24.1.6 The Government of India has mandated that fertilizer and power sectors get priority in allocation of domestically produced gas. In both these sectors, oil is not the alternative fuel to gas. In the power sector, as gas is mainly replacing coal as a fuel, oil price linkage to indigenously produced gas may not be the most relevant factor. 81% of the existing capacity of urea plants is based on natural gas, while 9% is naphtha-based and 10% is based on fuel oil. Here too replacing gas with oil is not a viable option as urea consumption is highly price-

elastic. Any increase in gas price for urea plants will certainly lead to a huge increase in costs affecting food security.

24.1.7 Further, oil price indexation works on import parity and replacement fuel principle. While it is clear that replacement fuel principle does not apply fully to the Indian market, import parity also has its limitations. Landed price of LNG includes customs duty, shipping, pipeline tariff, liquefaction costs, handling etc. These costs are extraneous to the producing activity and have no relevance to domestic producers. The competitiveness of domestic production will not be affected by the inclusion or exclusion of that component of the price which does not accrue to the producer at the well-head. Hence, %import parity+ will give a huge monetary benefit to domestic producers.

24.1.8 Planning Commission has correctly observed that high prices prevalent in LNG trade in the Asia-Pacific region can potentially ~~kill~~ the goose that lays the golden eggs<sup>1</sup>. It is neither in the producers' interest nor in the national interest to take natural gas to unviable levels by linking to crude prices. It is to be borne in mind that fertilizer companies in India were actively encouraged by GOI to convert to gas-based technology, with the expectation of domestic production at cheaper rates, thereby creating a stranded market for gas supplies. Similar promises and gas sales agreements were also entered into with power plants for domestic supply. If the new price becomes unviable to these two sectors, the demand for gas may slump drastically, as happened in 2005 in the US, and this would be against the common interests of producers and consumers alike, apart from not being in the national interest.

24.1.9 Further, oil-linked prices are mainly followed in Brazil and Thailand, for domestic production and consumption. In Brazil, Petrobras, which is a Government of Brazil company, is a major producer and the sole supplier and transmitter of natural gas. The benefit of higher prices directly accrues to the Government of Brazil in substantial proportion, which in turn subsidizes other important sectors. Even in Brazil, power companies get natural gas at regulated prices. Production and consumption in Thailand is too miniscule to serve as a viable model for India. On the other hand, Japan is a major importer of LNG, with large volumes linked to oil prices. Japan has recently decided to delink oil prices

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<sup>1</sup> Planning Commission Report of the Inter Ministerial Committee on Policy for Pooling of Natural Gas Prices and Pool Operating Guidelines (page 32)

from gas import prices. Russian export contracts too are increasingly indexed to European hub prices. Gas markets are consistently evolving away from oil price indexation and towards gas-on-gas competition.

24.1.10 **Netback from final product** mechanism works where the final product is traded freely. Fertilizer and power sectors are still subject to an administered price mechanism and hence this mechanism may not be relevant in India.

India has consciously moved away from below-cost pricing and cost-of-service based regulation under NELP.

## **24.2 An Approach to Gas Pricing Till Such Time When Gas-on-Gas Competition Becomes Feasible**

24.2.1 As discussed above, it may not be feasible to introduce gas-on-gas competition at this juncture. Therefore, a policy for pricing natural gas, till such time when gas-on-gas competition becomes feasible, is discussed below. However, it is recommended that Government review the situation after five years to examine the feasibility of introduction of gas-on-gas competition.

24.2.2 In the light of the discussion in § 24.1, a policy on pricing of natural gas for India is proposed. Since a competitive domestic price for gas does not currently exist and may not be expected to come about for several more years, the policy will have to be based on searching out from global trade transactions of gas the competitive price of gas at the global level. As the global market is not fully integrated in terms of physical flows and is also not everywhere liquid enough, it is proposed to combine two methods of search for such prices.

24.2.3 First, the netback price of Indian LNG import at the wellhead of the exporting countries should be estimated. Since there may be several sources of gas imports, the average of such netback of import prices at the wellheads would represent the average global price for Indian imports. It may be assumed that each gas exporting country also faces competition and, therefore, there is no reason to suppose that India faces any bias of being over-charged or under-charged vis-à-vis other competing buyers in the global gas market constructed through such aggregation for averaging. Such a netback average price may be

interpreted as the arm's length competitive price applicable for India, and such price may be estimated on the basis of recent historical transactions.

24.2.4 A second method of searching for a competitive price for India is to take the average of pricing prevailing at trading points of transactions . i.e., the hubs or balancing points of the major markets of continents. Currently, as per British Petroleum statistics, total natural gas consumption across the globe stands at 3.2 trillion cubic metres in the year 2011, of which North America, Europe & Eurasia, and Japan consumed around 65%. The average prices of natural gas consumed in these regions are also publicly available (British Petroleum Statistics / World Energy Intelligence Report, Platts etc.). Therefore, the weighted average of natural gas prices in these three major markets can be used for arriving at the price for domestic gas produced in India. For this, (a) the hub price (at the Henry Hub) in the US (for North America), (b) the price at the National Balancing Point of the UK (for Europe)<sup>2</sup>, and (c) the netback price at the sources of supply for Japan (a big buyer treated in the Asia-Pacific region as setting a benchmark for the region) may be taken as the prices most relevant for the purpose of approximating India's average price for producers at their supply points across continents. Such a global average price may also be interpreted as an arm's length competitive price for India.

24.2.5 Finally, the average of the prices arrived at through the aforementioned two methods may be taken. Such an overall average of global prices, derived on the basis of netback and hub / balancing point pricing principles, can be taken as the economically appropriate estimates of the arm's length competitive prices applicable for India. While the formulae detailed in this section directly or indirectly take into account the data of a wide range of transactions including those with India, the methodology neutralizes any bias for India and ensures the arm's length aspect of pricing, as best as possible.

24.2.6 The approach outlined in this section could be formulated into a Policy for Pricing of Natural Gas in India. The necessary steps for determining the two averages discussed above are presented in § 24.3.

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<sup>2</sup> According to International Gas Union (IGU) Report, 2011, the UK and Continental Europe are physically connected by pipelines and prices in European hubs are following NBP very closely. Hence, NBP is a good proxy for entire Europe including UK.

24.2.7 Before that, certain aspects having a bearing on the merits of the recommended pricing formula are discussed below.

24.2.8 Viewed from an investment perspective, it may be noted that the weighted average for gas production at well-head prices of North America, Europe and the exports to the Asia-Pacific shall indicate, by and large, what global gas players are getting from their investments. Hence, from an investment perspective as well, such a price may be considered as an appropriate reference price for domestic gas pricing in India.

24.2.9 It may be noted that although hub prices of natural gas in the US and Europe are slightly higher than well-head prices, since they include pipeline tariffs up to the hub, since such hub prices are readily available from standard sources, these may serve as better benchmarks.

24.2.10 The US and European markets have large volumes contributed by conventional/non-conventional gas sources and they also represent geological situations present in India. Further, the UK, continental Europe and FSU are developing into one single marketplace and hence need not be treated as stranded markets. FSU countries continue to have, by and large, a regulated price lower than the market price, much of the quantity consumed in FSU being below the European hub prices. While using European hub prices for FSU consumption will result in a slightly higher average price, it may be noted that even in FSUs, there is a distinct trend towards alignment of gas prices with European hub prices.

24.2.11 Indian imports of LNG are likely to grow rapidly over the next few years as domestic production is declining and new discoveries are yet to be commercialized. Hence, the netback to producers of LNG from such imports to India (both spot and term) can be used as a basis for deciding domestic gas prices in India. While currently a majority of Indian LNG imports are from the Middle East (mainly Qatar), the LNG import prices may not be a true representation of global gas prices. Since India's LNG imports from international markets are set to grow with time and become a well-diversified portfolio with supplies coming from all parts of the world (the US, Africa, Europe, Middle East and Australia), the recommended methodology of netback pricing may be more suitable.

## 24.3 Steps for arriving at the recommended pricing

24.3.1 While calculating netback to producers, the following components are deducted from the FOB price as they do not accrue due to production activity:

$$\text{Netback Price, } N = A - B - C. \quad (I)$$

$$P_{IAV} = (N_1 * V_1 + N_2 * V_2 + \dots) / (V_1 + V_2 + V_3 + \dots) \quad (II)$$

Where:

A = Imported LNG Price on Netback FOB available from World Energy Intelligence

B = Liquefaction costs at the respective loading port (source)

C = Transportation and treatment costs of natural gas from wellhead to liquefaction plant

$N_1, N_2$  are Producers' Netback, calculated as per Formula (I).

$V_1, V_2$  are volumes applicable to  $N_1, N_2$  Available from World Energy Intelligence or Platts

$P_{IAV}$  = Average Producer Net Back for Indian Imports for trailing 12 months

$V_1, V_2, V_3$  and A shall be for trailing 12 months period.

All imports, including term contracts, shall be included in the calculation.

Prices and volumes in the above calculation shall be for trailing 12 months, and  $P_{IAV}$  shall be arrived at for every month.

24.3.2 The average price of liquefaction costs with older plants is of the order of \$ 2.5/mmbtu<sup>3</sup>. For plants which started deliveries in 2010 or after, the liquefaction cost is of the order of \$ 3.5 to 4.0/mmbtu. A recent contract signed by GAIL with the Sabine Pass facility in United States of America for supplies to commence in the year 2016 from a brownfield project is around \$ 3.0/mmbtu.

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<sup>3</sup> Planning Commission Report of the Inter-Ministerial Committee on Policy for Pooling of Natural Gas Prices and Pool Operating Guidelines

Hence, it is recommended that an average of \$ 2.5/mmbtu may be adopted as the liquefaction cost while calculating the average producer netback for Indian imports and the weighted average price to producers in the global markets for older plants, and \$ 3.5/mmbtu for exports from plants starting deliveries after 2010. These figures may be reviewed after five years.

The trend of liquefaction costs can be ascertained from the data available from the reports of Facts Global LNG and Wood Mackenzie.

24.3.3 The transportation cost from the well-head to the liquefaction plant may be considered as around \$ 0.5/mmbtu. This includes handling charges and sweetening cost of gas.

$$P_{WAV} = (A_1 * P_{HH} + A_2 * P_{NBP} + A_3 * P_{JAV}) / (A_1 + A_2 + A_3) \quad (III)$$

$P_{WAV}$  = Weighted average price to producers in the global markets

$A_1$  = Total volume consumed in North America at average Henry Hub prices on yearly basis

$P_{HH}$  = Annual average of daily prices on Henry Hub for the relevant year

$A_2$  = Volume consumed through various hubs in Europe/Eurasia in the relevant year (entire consumption of Europe and FSU)

$P_{NBP}$  = Annual average of daily prices on National Balancing Point (NBP) in the UK for the relevant year

$A_3$  = Volume imported by Japan in the relevant year

$P_{JAV}$  = Yearly weighted average producers netback price of gas in Japan for the relevant year (weighted by the total volume of long term and spot imports)

$P_{JAV}$  shall also be calculated as  $P_{IAV}$  is calculated in Formula (I).

24.3.4 Prices and volumes used in this formula shall be for trailing 12 months period. It is recommended that  $P_{WAV}$  be calculated every month by the above formula.

24.3.5 The netback price of LNG to be delivered in Japan from various potential sources across the globe can be determined from the FOB price at the loading country. The netback FOB prices and volumes at those prices from various exporting countries are available from LNG Daily and World Energy Intelligence websites. The FOB price includes liquefaction costs of gas at the plant in the



producing country at the loading port, plus the transportation, including handling and sweetening charges of the gas from the producing asset to the liquefaction plant. Thus,

**Producer's Netback for LNG Import**

$$= \text{Netback FOB Price} - \text{Liquefaction Cost} - \text{Transportation Cost (including Sweetening and Handling Charges)} \quad \text{(IV)}$$

The formulae for  $P_{IAV}$  and  $P_{WAV}$  give an average price which producers across the world are realizing through production of natural gas.  $P_{IAV}$  is specific to India as it is calculated from Indian imports. Hence, an average of  $P_{IAV}$  and  $P_{WAV}$  will represent the recommended appropriate price  $P_{AV}$  for domestic producers:

$$P_{AV} = (P_{IAV} + P_{WAV}) / 2 \quad \text{(V)}$$

24.4 It is clarified that the proposed pricing formula would only apply prospectively and is not proposed for application to gas prices already approved.

24.5 The proposed pricing formula would apply to all sectors uniformly, while allocation of gas will be as per the prevailing Gas Utilization Policy (GUP) of the Government.

## **Chapter VI**

### **Summary of Recommendations**

## Summary of Recommendations

### **I. Committee's Recommendations on ToRs (i) & (ii)**

1.1 The committee recommends a new contractual system and fiscal regime based on a post-royalty-payment revenue-sharing to overcome the difficulties in managing the existing model based on the Pre-Tax Investment Multiple (PTIM) methodology and the cost-recovery mechanism. The extant fiscal model, with primary focus on upstream costs, has been found to be a major bottleneck in expeditious performance of exploratory work. The proposed model should overcome the constraints inherent to the cost-based monitoring mechanism of the existing PSC, and should meet the Government's objective of promoting rapid exploration and development in the oil and gas sector. *[Paragraph 11.3]*

1.2 The committee recommends that the proposed contractual model be based on a two-dimensional matrix. The proposed model envisages that the production or post-royalty value of the combined output of oil and gas be shared between the Government and the Contractor. Such a production sharing will be linked to the average daily production and prevailing average of oil and gas prices in a well-defined period. The committee notes that in the proposed system, the Government will be able to capture economic rent in the form of royalty and revenue share of hydrocarbons, right from the onset of production. The committee further recognises that the Government will be able to secure a share any windfall profits accruing on account of a price surge or a geological surprise by way of a huge hydrocarbon find. *[Paragraph 5.10.1]*

1.3 The production tranches will be different for various sectors (on land, shallow water and deep water), and price bands will be based on historical and prevailing price trends. Production and price bands will be suitably designed after due deliberation and considering available historical data for Indian geological basins. *[Paragraph 11.5]*

1.4 The production share for each cell of the matrix will be biddable, and the winning bid will be determined on the basis of competitive bidding. The bid has

to be progressive and incremental with respect to the Government take, *i.e.*, the Government take will be in an ascending order for increases in production and price. The NPV of Government's share in revenue, using the benchmarked production profile for the block, will be one of the deciding criteria for assessing a bid. *[Paragraph 11.6]*

1.5 The Government may not introduce a mandatory minimum percentage share for the highest price/production cell of the matrix. The Government would prefer the production share of the Government's and Contractor's take to be decided by competitive bids in the price-production matrix. However, any abnormally low bid, in case of a single bid for a block, which may be the result of cartelisation or information asymmetry, would require close scrutiny to safeguard government take. *[Paragraph 11.7]*

1.6 The overall bidding parameters of the Minimum Work Programme (MWP) commitment and the fiscal package will remain the same as at present. Technical capability will also continue to have the same treatment as it obtains currently. Only the bid evaluation criteria for the fiscal package will change with the proposed changes in the fiscal model, although its weight in the overall bid may remain the same. *[Paragraph 11.8]*

1.7 The model so proposed will be applicable for all future contracts, including Coal-Bed Methane (CBM) contracts. Only the production tranches will be changed, depending on historical data available at the time of award of CBM blocks. *[Paragraph 11.9]*

1.8 All the PSCs signed by the Government up to the ninth round of NELP will continue with the existing fiscal model, ensuring the sanctity of these contracts. Moreover, in the forthcoming rounds as well the PSC structure will be retained, albeit with a different fiscal model. *[Paragraph 11.4]*

1.9 As there will be no element of cost-recovery in the proposed system, the role of the MC or of the Government nominees on the MC will be largely related to monitoring and control of technical aspects. The functions pertaining to approval of annual budgets, audited accounts and auditors will not be required. The new regime is expected to help overcome uncertainty with regard to the time

involved in securing various categories of approvals from the MC. [Paragraphs 11.10 & 11.11]

1.10 A major impact of the proposed model in the interest of hydrocarbon exploration will be that Contractors can be allowed to carry out further exploration throughout the Mining Lease (ML) period in the ML area. [Paragraph 11.15]

1.11 Other contractual bottlenecks for exploration and exploitation of hydrocarbons may be addressed with suitable amendments in the provisions for the exploration period, flexibility in carrying out the appraisal programme, development of discoveries in deep-water and frontier areas, *force majeure*, etc. [Paragraph 11.14]

1.12 It is perceived that prospectivity in offshore blocks along the Eastern and Western coastline is very high and there is enthusiastic response from global majors. These blocks are in ultra-deep waters, which can be anywhere beyond 1,500 metres in depth. Further, along the Eastern coastline, reservoirs are characterised by high pressure and high temperatures. The monsoon vagaries limit the weather window effectively to four months. Hence, the exploration and development of these blocks is costlier than shallow blocks. It needs to be compensated by a suitable fiscal package other than the existing seven-year tax holiday and biddable fiscal parameters. The committee recommends that the tax holiday can be extended to ten years from the date of first production in such ultra-deep water blocks. [Paragraph 11.16]

1.13 Since the proposed fiscal regime would be new in the Indian context, the regime may be reviewed after five years. [Paragraph 11.17]

## **II. Committee's Recommendations on ToR (iii)**

**Policy Related Issues: Constitution of an Inter-Ministerial Committee [§ 15.1]**

2.1 As many contract management issues hampering execution of subsisting PSCs are policy related, the committee recommends the constitution of an Inter-

Ministerial Committee to suggest policy solutions to these issues to the Ministry of Petroleum & Natural Gas (MoP&NG), which may obtain CCEA's approval. *[Paragraph 15.1.1]*

2.2 This Inter-Ministerial Committee may have representatives from the Ministries of Petroleum & Natural Gas, Environment & Forests (MoEF), Defence, Finance, and Law & Justice. For issues pertaining to Coal-Bed Methane (CBM), a representative from the Ministry of Coal may be co-opted. *[Paragraph 15.1.2]*

### **Issues concerning Contract Management and the Fiscal Regime [§ 15.2]**

2.3 There is frequent criticism that presence of Government nominees on the Management Committee (MC) results in a conflict of interest between regulation and proprietorship. However, a similar situation prevails in many sectors of the economy, including the banking sector. Government, as the owner of petroleum and natural gas, engages contractors as per the terms of an agreement to explore, extract and monetise these resources. Hence, the MC should be seen as a joint effort to optimise the results for the owner and the contractor. However, as the owner of the resources, the responsibility of their management rests with the Government. *[Paragraph 15.2.1]*

2.4 To facilitate smooth functioning of the MC, both the representatives of the Government on the MC may devise an internal mechanism to act collectively in the decision-making process and address the issues jointly, in a firm manner. DGH and MoP&NG should firm up Government's stand before the MC meeting. *[Paragraph 15.2.2]*

2.5 Decisions of the MC should be quick, as per contractual provisions, and, as far as possible, MC resolutions should be signed on the date of meeting itself. MC meetings may always include Action Taken Notes / Action-points from the last meeting as the first agenda item. Approval/review of any decisions taken by the Contractor in between two MC meetings should also be an agenda item. It may also be ensured that the periodicity of MC meetings under PSC provisions is adhered to. *[Paragraph 15.2.3]*

2.6 In any case, if unanimity between the Government nominees on any particular item on the MC agenda cannot be achieved within a reasonable period

of time, the issue may be referred to the Empowered Committee of Secretaries (ECS), as recommended below. *[Paragraph 15.2.4]*

### **Empowered Committee Mechanism [§ 15.3]**

2.7 An analysis of pending issues indicates that most of them are due to minor deviations from the PSC framework. A majority of these concern timelines prescribed in the PSC. There are also issues which can be resolved by a constructive reading of the PSC. *[Paragraph 15.3.1]*

2.8 There is an existing mechanism of Empowered Committee of Secretaries (ECS) approved *vide* Cabinet Committee of Economic Affairs (CCEA) resolution dated 2<sup>nd</sup> December 2003 to consider extension in the exploration period beyond the timelines stipulated in the PSC, depending upon the exigencies prevailing in the Block. The CCEA Resolution empowers the ECS for extension of exploration periods in Pre-NELP and NELP Blocks. The same ECS can be invested with powers to consider extension of other timelines prescribed in the PSC pertaining to appraisal, submission of the commerciality, Field Development Plan submission, etc. As the Ministries of Law and Finance are represented on this committee, a comprehensive government view can emerge. This arrangement can resolve the anxieties of government staff dealing with the contract and ease decision-making. Further, this committee may also be empowered to reconcile and resolve minor technical disputes by including experts on the subject as special invitees. Selection of these experts may be done from the Government, regulatory organisations, and national scientific and technological organisations, while ensuring that no conflict of interest exists for such persons. Whenever such dispute resolution is being resorted to, specific consent of the Contractor should be obtained. *[Paragraph 15.3.2]*

2.9 The committee recommends that all such contractual issues raised during the entire period of implementation of existing contracts may be considered by the ECS, which has certain delegated powers under NELP. *[Paragraph 15.3.3]*

### **Codification of Good International Petroleum Industry Practices (GIPIP) [§ 15.4]**

2.10 On technical and safety related issues the committee recommends that, DGH may undertake codification of Good International Petroleum Industry Practices (GIPIP) that are of relevance to the Indian geological set-up. This may be done by a Working Group under the chairpersonship of Director General, Hydrocarbons and having experts from the Directorate General of Hydrocarbons, with nominees from MoP&NG, MoEF, Defence Research and Development Organization (DRDO) and other expert agencies. In case of ambiguities on technical and safety related aspects, the Contractor may refer the issues to this Working Group. *[Paragraph 15.4.1]*

2.11 The Directorate General of Hydrocarbons (DGH) may be strengthened to render independent technical advice to the Government. DGH may recruit independent experts (who shall not be entrusted with representing the Government on the MC) for its core functions of reservoir, safety and other technical aspects of contract management. *[Paragraph 15.4.2]*

### **III. Recommendations on ToR (iv)**

3.1 Out of a total of 228 active PSCs, entered into up to Round IX of NELP, for which audit is to be conducted, audit by CAG is essential for PSC blocks with discoveries as correctness of cost recovery would be relevant only in these blocks. Audit of blocks without any discoveries may be conducted by engaging qualified accounting firms. PSCs may be categorised as follows for the purpose of audit:

- a) **Exploration phase PSCs:** Audit of selected blocks to be carried out by CAG, with the remaining to be carried out by CAG-empanelled auditors.
- b) **Development phase PSCs:** Audit to be conducted by CAG in all important and financially critical blocks. Such audit can be done once in two years (in line with the timelines suggested in the PSC) for the selected blocks by CAG, while in all other years this task can be performed by audit firms empanelled by CAG. Audit of the remaining blocks can be entrusted to auditors empanelled with CAG, with their audit reports being reviewed by CAG.



- c) **Production phase PSCs:** Audit of selected blocks to be carried out by CAG, with the remaining blocks to be carried out by CAG-empanelled auditors.

*[Paragraph 18.1]*

3.2 Audit may be carried out by the office of CAG in accordance with financial materiality. For this, accounts of blocks would be sent to the CAG, for selection of blocks for audit by CAG. Periodicity of audit for various blocks may be decided by the office of CAG. This will become a regular feature. As such, there would be no requirement for requesting CAG for a special audit every time. *[Paragraph 18.2]*

3.3 The audit criteria adopted by the CAG can be shared with auditors carrying out audit under the PSC for them to follow while auditing those blocks that are not being audited by CAG. *[Paragraph 18.3]*

3.4 As the element of cost recovery is not applicable to CBM blocks and nominated blocks, CAG audit for such blocks may not be required, and production monitoring through field surveillance may be considered adequate. Similarly, in the case of the new fiscal regime recommended in relation to the committee's terms of reference (i) and (ii), audit by CAG would not be necessary. *[Paragraph 18.4]*

3.5 Audit by CAG may be carried out within a period of two years of the financial year under audit, as specified in PSCs. This will resolve many issues relating to exploration and production activities. Further, where investment is huge (a \$1 billion threshold may be adopted), a suitable mechanism of concurrent audit may be considered. *[Paragraph 18.5]*

3.6 Audit by CAG under Section 1.9 of the PSC should be prior to performance audit of the Ministry so that corrective actions emerging from CAG audit could be taken up by the Government in order to protect the Government revenue. The CAG audit is to be carried out strictly as per the provisions of the PSCs. Performance audit, normally done by CAG for the Ministry, can address other concerns of the auditor. *[Paragraph 18.6]*

## **IV. Recommendations on ToR (v)**

### **Relevance of Different Price Formations [§ 24.1]**

4.1 Public sector companies producing gas have a highly regulated pricing system in place. Gas prices in India can, in principle, incentivize investment in the Indian upstream sector, so that production in India reaches optimum levels and all exploitable reserves put to production expeditiously. India also needs to ensure that producers don't cartelise as there is a huge unmet demand. The twin objectives of expediting production and avoiding cartelisation can be achieved by ensuring that producers in India get at least the average price of what producers elsewhere are getting. *[Paragraph 24.1.2]*

4.2 Gas-on-gas competition for price discovery will become feasible once import infrastructure is ramped up and domestic production and transportation infrastructure grow. Therefore, Government may consider reviewing the situation after five years to examine the feasibility of its introduction. *[Paragraph 24.1.4.1]*

### **An Approach to Gas Pricing Till Such Time When Gas-on-Gas Competition Becomes Feasible [§ 24.2]**

4.3 As discussed above, it may not be feasible to introduce gas-on-gas competition at this juncture. Therefore, a policy for pricing natural gas, till such time when gas-on-gas competition becomes feasible, is discussed below. However, it is recommended that Government review the situation after five years to examine the feasibility of introduction of gas-on-gas competition. *[Paragraph 24.2.1]*

4.4 In the light of the discussion in § 24.1, a policy on pricing of natural gas for India is proposed. Since a competitive domestic price for gas does not currently exist and may not be expected to come about for several more years, the policy will have to be based on searching out from global trade transactions of gas the competitive price of gas at the global level. As the global market is not fully integrated in terms of physical flows and is also not everywhere liquid enough, it

is proposed to combine two methods of search for such prices. [Paragraph 24.2.2]

4.5 First, the netback price of Indian LNG import at the wellhead of the exporting countries should be estimated. Since there may be several sources of gas imports, the average of such netback of import prices at the wellheads would represent the average global price for Indian imports. It may be assumed that each gas exporting country also faces competition and, therefore, there is no reason to suppose that India faces any bias of being over-charged or under-charged vis-à-vis other competing buyers in the global gas market constructed through such aggregation for averaging. Such a netback average price may be interpreted as the arm's length competitive price applicable for India, and such price may be estimated on the basis of recent historical transactions. [Paragraph 24.2.3]

4.6 A second method of searching for a competitive price for India is to take the average of pricing prevailing at trading points of transactions . i.e., the hubs or balancing points of the major markets of continents. For this, (a) the hub price (at the Henry Hub) in the US (for North America), (b) the price at the National Balancing Point of the UK (for Europe), and (c) the netback price at the sources of supply for Japan (a big buyer treated in the Asia-Pacific region as setting a benchmark for the region) may be taken as the prices most relevant for the purpose of approximating India's average price for producers at their supply points across continents. Such a global average price may also be interpreted as an arm's length competitive price for India. [Paragraph 24.2.4]

4.7 Finally, the average of the prices arrived at through the aforementioned two methods may be taken. Such an overall average of global prices, derived on the basis of netback and hub / balancing point pricing principles, can be taken as the economically appropriate estimates of the arm's length competitive prices applicable for India. While the formulae detailed in this section directly or indirectly take into account the data of a wide range of transactions including those with India, the methodology neutralizes any bias for India and ensures the arm's length aspect of pricing, as best as possible. [Paragraph 24.2.5]

4.8 The approach outlined in this section could be formulated into a Policy for Pricing of Natural Gas in India. The necessary steps for determining the two averages discussed above are presented in § 24.3. *[Paragraph 24.2.6]*

4.9 It is clarified that the proposed pricing formula would only apply prospectively and is not proposed for application to gas prices already approved. *[Paragraph 24.4]*

4.10 The proposed pricing formula would apply to all sectors uniformly, while allocation of gas will be as per the prevailing Gas Utilization Policy (GUP) of the Government. *[Paragraph 24.5]*

## **ANNEXURE A**

### **PRIME MINISTER'S OFFICE**

South Block  
New Delhi-110011

Subject: - Review of profit sharing mechanism and PSCs in Hydrocarbon exploration.

Reference is invited to D.O. No.253/2012/MoPNG dated 30.03.2012 from Minister of P&NG to the Prime Minister on the above subject.

2. Prime Minister has approved the constitution of a Committee to review profit sharing mechanism and PSCs in Hydrocarbon exploration. The composition of the Committee is:

- (i) Dr. C. Rangarajan . Chairman, PM's Economic Advisory Council .  
Chairman
- (ii) Shri B.K. Chaturvedi . Member, Planning Commission
- (iii) Justice Shri Jagannadha Rao, Former Judge of the Supreme Court
- (iv) Prof. Ramprasad Sengupta
- (v) Shri JM Mauskar, former IAS officer
- (vi) Shri Joeman Thomas, MD, ONGC Videsh Ltd.

3. The Secretary, PM's Economic Advisory Council will be the convener of the Committee.

4. The following terms of reference for the Committee are approved:-

- (i) Modification necessary for the future PSCs after a review of the existing PSCs, including in respect of the current profit-sharing mechanism with the Pre-Tax Investment Multiple (PTIM) as the base parameter.
- (ii) Exploring various contract models with a view to minimize the monitoring of expenditure of the contractor without compromising,

firstly, on the hydrocarbons output across time and, secondly, on the Government's take.

- (iii) A suitable mechanism for managing the contract implementation of PSCs which is being handled at present by the representation of Regulator/Government nominee appointed to the Managing Committee.
- (iv) Suitable government mechanisms to monitor and to audit GOI Share of profit petroleum.
- (v) Structure and elements of the Guidelines for determining the basis or formula for the price of domestically produced gas, and for monitoring actual price fixation.
- (vi) Any other issues relating to PSCs.

5. A suitable officer of the rank of Director/DS, MoP&NG may be attached as Secretary for the Committee to handle all administrative matters as well as provide research assistance. MoP&NG will meet the expenditure on behalf of the Committee as well as provide all required support including meeting, travel and out of pocket expenses of the Committee members and remuneration/sitting fee, if any.

6. The Committee will submit its recommendation by 31.08.2012.

7. The undersigned is directed to request MoP&NG to issue necessary orders constituting the Committee as mentioned above.

-sd-

(Sanjay Lohiya)

Director

Tel: 2301 8876

Fax: 2301 6857 & 2301 9545

Secretary, Ministry of Petroleum & Natural Gas

PMO ID No.330/31/C/47/2011-ES.I

Dated: 04.12.2012

Copy to:

Secretary, Economic Advisory Council to the Prime Minister

## **ANNEXURE B**

### **History of the Search for Oil in India**

1. The search for oil commenced in India in 1866, following a hint of oil show detected by a fleet of elephants carrying logs, by Mr Goodenough of McKillop Stewart Company. The first discovery was made in 1889 at Digboi by Assam Railway and Trading Company (ARTC), a company registered in London. Burma Oil Company (BOC) entered into the Indian market in 1911 and entered into exploration in India in 1921 by taking over ARTC.
2. Seismic surveys were initiated in and a major ~~High~~located at Nahorkatiya in Assam. The first oil discovery was made in Nahorkatiya in 1953.
3. At the time of Independence, matters relating to oil were dealt with a Petroleum Division of the Department of Works, Mines and Power. With the intention of intensifying and spreading exploration to various parts of the country a separate Oil and Natural Gas Directorate (ONGD) was set up in 1955, as a subordinate office under the then Ministry of Natural Resources and Scientific Research. This was made into a Commission with enhanced powers in August 1956 and converted into a statutory body in 1959. ONGC spread the exploration efforts into various sedimentary basins and initiated exploratory drilling in the Himalayan foothills in 1957, with the drilling of the first well Jawalmukhi-1 in Himachal Pradesh which indicated hydrocarbon. ONGC's geo-scientific surveys and exploratory drilling activities were also extended to UP (1962), Bihar (1963), Tamil Nadu (1964), Rajasthan (1964), J&K (1970), Kutch (1972) and Andhra Pradesh (1978).
4. A major boost was the discovery of oil and gas in Cambay Basin in 1958. Oil was struck at Ankleshwar in Gujarat, at Rudrasagar in 1960, and at Geleki in Assam in 1968.

5. For providing greater impetus to exploration in the North-eastern part of India, Oil India Private Ltd. (OIL) was incorporated in February, 1959. It was registered as a Rupee Company, AOC/BOC owned two-thirds of the shares while Gol owned the remaining one-third. In 1961, the Government of India and BOC transformed OIL into a Joint Venture Company (JVC) with equal partnership.
6. ONGC started offshore seismic surveys in Gulf of Cambay in 1962 and followed this up with surveys carried out in the Bombay Offshore in 1972-73. This resulted in the identification of a large structure in Bombay Offshore which was taken up for drilling in 1974, leading to India's biggest commercial discovery, thereby establishing a new hydrocarbon province. Encouraged by the success at Bombay Offshore, number of structures were identified and exploration was spread to other offshore areas, both in the Western Offshore (resulting in significant discoveries at Bassein and Neelam) and in the Eastern Offshore (resulting in substantial accumulations at Ravva, PY-3 etc.).
7. After OIL became a wholly owned Government enterprise in 1981 with the Government taking over BOC's 50 per cent equity and the management of Digboi oilfields, OIL started expanding its exploration activities outside Northeast to Mahanadi Offshore in 1978, Mahanadi Onshore in 1981, North-East Coast Offshore in 1983, Rajasthan On-land in 1983, Saurashtra Offshore in 1989 and Ganga Valley areas in UP in 1990.
8. The requirement of meeting the growing demand of oil & gas prompted the Government to involve the private sector. Exploration bidding rounds started in 1979, and till 1995 nine exploration bidding rounds including one JV round were held. Even though these did not yield the desired results could succeed in generating some interest in the international oil industry about explorations in India. The discovered fields of ONGC viz. Ravva, Mid & South Tapti, Mukta and Panna fields were offered to private sector for development.
9. The public sector undertakings were also encouraged to acquire participating interest in blocks abroad. Accordingly ONGC set up a separate subsidiary, OVL.



10. As a major part of the sedimentary basins of India remained un-/under-explored and exploration bidding rounds did not have the desired results, Government of India conceptualized a new exploration policy, called the New Exploration Licensing Policy (NELP), during 1997-98 to provide an equal platform to both public and private sector companies in exploration and production of hydrocarbons, with Directorate General of Hydrocarbons (DGH) as the nodal agency for its implementation.
11. With the introduction of the New Exploration Licensing Policy (NELP), the induction of much-needed capital and state-of-the-art technology to explore the sector became possible. With India's policies and regulations becoming among some of the most transparent in the world, the NELP helped foster healthy competition between National Oil Companies and private (including multinational) companies. The development of the exploration sector has been significantly boosted through this policy, which effected a major liberalization in the sector and created pathways for private and foreign investment, and under which 100% Foreign Direct Investment (FDI) was allowed. Under NELP, which became effective in February 1999, a process of competitive bidding is followed, wherein acreages are offered to participating companies. By mid-2012, nine rounds of bidding have been concluded, along with four rounds for Coal Bed Methane (CBM) blocks.

### **E&P Regulatory Regime**

12. Post-Independence, the upstream petroleum sector evolved through three different regulatory regimes - Nomination, pre-NELP/ bidding rounds and NELP. Various blocks under operation have been awarded under one or the other of these three regulatory regimes.

### **Nomination Regime**

13. Until 1955, exploration activities were carried out by private oil companies and were mainly restricted to Assam. While framing the Industrial Policy Statement of 1948, the development of petroleum industry in the country was given top priority. In April 1956, the Gol adopted the Industrial Policy Resolution, which placed mineral oil industry among the schedule 'A'

industries, the future development of which was to be the sole and exclusive responsibility of the State. ONGD was set up in 1955 and became a commission in 1956. Oil India Private Limited was incorporated in February, 1959.

14. As per the policy, NOCs were eligible to venture into any part of the basins for exploration / production, with no competition from private/ foreign companies. Under this regime, exploration blocks were offered to national oil companies on nomination basis. The prioritization of inter- and intra-basin exploration programme was largely determined by the NOCs themselves. The exploration areas could be identified by NOCs and, on application, Petroleum Exploration Licenses (PELs) could be sought and awarded any time. There was no Minimum Work Programme (MWP) commitment or mandatory relinquishment. The PELs were awarded for 4 years initially and could be extended by two years. NOCs were required to pay full statutory levies, viz. royalty to the state government / central government for on-land/off-shore areas and cess to the central government. The combined burden of royalty and cess on the national oil companies was huge and was revised periodically. National oil companies pay customs duties in the nomination fields granted prior to 1.4.1999. ONGC and OIL have also incurred substantial exploration costs in discovering oil and gas in on-land and offshore areas. ONGC spread out to different sedimentary basins across India for its exploration activities, whereas OIL largely concentrated to the North-eastern part of India. Numbers of discoveries, including offshore discoveries, were made in seven basins. On discovery, Mining Lease for the area could be applied for. The produced hydrocarbons were sold under the Administered Price Mechanism (APM).

15. *Progress Achieved:* As a result of sustained exploration campaign by NOCs, exploration activities, which were in their infancy and limited to a small part of Assam, were spread into large parts of India, including offshore. A number of discoveries were made in different basins. The first such discovery outside Assam was in Cambay Basin in 1958. ONGC's geo-scientific surveys and exploratory drilling activities were also spread out to U P (1962), Bihar (1963), Tamil Nadu (1964), Rajasthan (1964), J&K (1970), Kutch (1972) and Andhra Pradesh (1978). A number of fields

were discovered, establishing different basins. In 1974 the offshore field at Bombay High was discovered off the west coast. The G-1 field was discovered in 1980 off the East coast. At the time of independence, India's domestic oil production was just 250,000 tonnes per annum. This grew to 34 million tons by 1989. This was no mean achievement, considering the fact that this was achieved by two companies under severe financial restrictions.

16. *Status:* After the introduction of NELP, no more acreage was offered under Nomination. However NOCs were allowed to continue with pre-existing acreages with certain accompanying conditions. This resulted in NOCs competing for acreages under NELP.
17. *Merits and demerits:* The Nomination policy provided the required support for the growth of the sector through a sustained campaign. While there was lot of pessimism about the prospectivity of Indian sedimentary basins, especially for international majors, the NOCs could reverse this perception. The intensive exploration resulted in a string of discoveries and up gradation of six basins into producing basins. The most important contribution of NOCs has been their self-reliance and the development of core competence in E&P activities at a globally competitive level. The Indian NOCs have established in-place volume of the order of 8 Billion Tonnes (O+OEG) and have contributed more than 80-85% of the cumulative production of oil & gas till now. Another significant factor was the APM for the produced hydrocarbon which protected the economy from crude oil price fluctuations. The constraints were the funding of capital investments by NOCs which resulted in large areas remaining un-/under-explored. This resulted in NOCs not meeting the requirements of growing demand for oil. The primary objection to the use of this regime for nominating private companies was that appropriate economic rent to be paid to the Government could not be discovered rent under market conditions.
18. *Pre-NELP bidding rounds:* The growing demand for oil & gas prompted the Government to involve the private sector. Exploration bidding rounds started in 1979. However, the early rounds were not successful. The first four rounds took 12 years to complete (1979-91). The next five rounds

came over a period of two years (1994-95) and succeeded in generating some interest in the international oil industry. An innovation was also introduced in the 9th round - known as the JV round - to reduce the risk for the private investors by associating ONGC/OIL as partners in these exploration ventures.

19. *Details:* The NOCs, while not participants in the bidding process, were the licensee on behalf of GoI. NOCs, as licensees, were required to bear the entire liability for payment of statutory levies, namely royalty and cess. However, exploration blocks were offered to various companies in order to attract private investments in exploration and production of oil. As per the PSCs under this regime, the share of the national oil companies could be up to a maximum of 40 per cent and the parties to the contract were to share profit oil and profit gas separately from each field on the basis of post-tax returns. This way, ONGC and OIL carried an additional burden of Royalty and Cess. The profit petroleum was made biddable. Payment of customs duties was exempted. However, Corporate Tax at the rate of 50% was levied on foreign Companies (56.375% for rounds 1 & 2).
20. *Progress Achieved:* The Government of India has signed PSCs for 28 exploration blocks under Pre-NELP rounds since 1993. Out of these, 11 blocks have been relinquished / surrendered. At present, 14 exploration blocks covering around 41,000 sq. km are under operation.
21. *Status:* Besides development of small and medium sized fields, significant discoveries were made in the Pre-NELP exploration blocks like Mangala, Aishwarya, Bhagyam, Shakti (by Cairn), PY-3 (by Hardy), Palej-Promoda (by HOEC) and Tarapur (by GSPC).
22. *Merits and demerits:* This policy provided a window of opportunity for private participation and was the basis for further evolution and opening up of the sector and the framing of the New Exploration Licensing Policy. The entry of foreign and private sector participants infused required capital into the sector, especially for developing discovered fields like Ravva along the east coast and Panna, Mukta and Tapti along the west coast. The main demerit of Pre-NELP regime was that while revenue to the Government was reduced as a result of incentives provided, payment

of all levies and statutory payments became the responsibility of the NOCs, being the licensee. Even though the discovered fields elicited much interest, the exploration rounds were not received well.

## **Discovered Field Policy**

### ***First Development Round (1992)***

23. For faster development of small and medium sized discovered fields of ONGC & OIL Government of India announced the First Round of bidding for development of small and medium sized oil and gas fields in 1992. A total of 31 small-sized discovered fields were offered, out of which 10 were offshore and 21 on-land. The offshore basins in which the offered fields were located included the Andaman, Krishna-Godavari, Cauvery and Bombay basins. On-land blocks were in the Gujarat and Assam basins.

24. Out of 12 medium-sized fields offered, 6 were offshore 6 were on-land, which were to be developed by the companies in joint venture with ONGC/OIL. Offshore fields offered included the Ravva, Panna, Mukta, Mid and South Tapti and the R-Series. On-land fields included fields in Arunachal Pradesh, Assam and Rajasthan.

### ***Development Round (1993)***

25. In 1993, the second development bidding was announced for development of medium sized and small sized oil & gas fields in India. Eight medium-sized and 33 small-sized fields were on offer. The medium-sized fields were to be developed as a joint venture between the companies and ONGC/OIL, while the small-sized fields were to be developed by companies on their own, with no participation from ONGC/OIL. Of the 33 small size fields, 4 were offshore, and the balance 29 on-land. Of the 8 medium sized fields, 2 were offshore (Ratna & R-Series and Bassein Oil Rim and 6 on land, located in the Cambay and the Upper Assam basins.

26. *Merits & Demerits:* Award of the fields led to infusion of CAPEX at a time when the country was facing a financial crisis. It also led to development of the fields and an increase in production. However, it is perceived that since ONGC had taken entire exploration risk, the system was unfair to ONGC and GOI.

### **New Exploration Licensing Policy (NELP)**

27. *Details:* New Exploration Licensing Policy (NELP) was formulated by the Government of India, during 1997-98, to provide a level playing field to both public and private sector companies in the exploration and production of hydrocarbons, with Directorate General of Hydrocarbons (DGH) as the nodal agency for its implementation. Government of India's commitment to the liberalization process is reflected in NELP, which has been conceptualized keeping in mind the immediate need for increasing domestic production.

28. *Status:* So far, GoI has concluded nine bidding rounds under NELP.

<b>NELP ROUND</b>	<b>TOTAL BLOCKS OFFERED</b>	<b>TOTAL BLOCKS PSC SIGNED</b>
NELP-I	<b>48</b>	<b>24</b>
NELP-II	<b>25</b>	<b>23</b>
NELP-III	<b>27</b>	<b>23</b>
NELP-IV	<b>24</b>	<b>20</b>
NELP-V	<b>20</b>	<b>20</b>
NELP-VI	<b>55</b>	<b>52</b>
NELP-VII	<b>57</b>	<b>41</b>
NELP-VIII	<b>70</b>	<b>31</b>
NELP-IX	<b>34</b>	<b>13</b>

29. A number of discoveries have been made, and the blocks are at various stages of exploration / appraisal / development, while one (NELP-I) block is on production.

30. *Merits & demerits:* To attract more investment for oil exploration and production, NELP has steered steadily towards a healthy spirit of competition between National Oil Companies and private companies. This has been a landmark event in the growth of the upstream oil sector in India. Foreign and Indian private companies are invited to supplement the efforts of National Oil Companies in the discovery of hydrocarbons. The development of E&P sector has been significantly boosted through this policy of Government of India, which effected major liberalization in the sector and opened up the E&P sector for private and foreign investment, and under which 100% Foreign Direct Investment (FDI) was allowed. Under NELP, which became effective in February 1999, acreage is offered to participating companies through a process of open, competitive bidding.

Some of the demerits are:

- Design of the fiscal terms could lead to late accrual of profit oil to the Government.
- Administration of the PSC calls for an in-depth monitoring mechanism by the regulatory authority
- The Contractors perceive Government's administrative efforts, taken with the larger public interest in mind, as micromanaging the oil & gas field operations through the Management Committees (MC). Management Committees (MC) often find themselves in a stalemate over consideration of such issues, especially financial issues related to budgets. Many of these issues remain unresolved for long, thereby adversely impacting achievement of the basic objectives of enhanced pace of hydrocarbon exploration and exploitation.

## ANNEXURE C

The relevant portions of Article 25 of the PSC that pertain to Government Audit are as follows:-

**Article 25.5** The Government shall have the right to audit the accounting records of the Contractor in respect of Petroleum Operations as provided in the Accounting Procedure.

**Article 25.6** The accounting and auditing provisions and procedures specified in this Contract are without prejudice to any other requirements imposed by any statute in India, including, without limitation, any specific requirements of the statutes relating to taxation of Companies.

**Article 25.7** For the purpose of any audit referred to in Articles 25.5, the contractor shall make available in original to the auditor all such books, records, accounts and other documents and information as may reasonably be required by the auditor during normal business hours.

The relevant portions of the Accounting Procedure regarding Government Audit are as follows:-

### **Section 1.9 Audit and Inspection Rights of the Government**

**1.9.1** Without prejudice to statutory rights, the Governments, upon at least twenty (20) Business days advance written notice to the Contractor, shall have the right to inspect and audit, during normal business hours, all records and documents supporting costs, expenditures, expenses, receipts and income, such as the Contractor's accounts, books, records, invoices, cash vouchers, debit notes, price lists or similar documentation with respect to the Petroleum Operations conducted hereunder in each Year, within two (2) years (or such longer period as may be required in exceptional circumstances) from the end of such Year.

**1.9.2** The Government may undertake the conduct of the audit either through its own representatives or through a qualified firm of recognized chartered accountants, registered in India or a reputed consulting firm,



appointed for the purpose by the Government and the costs of audit in case of Government auditor(s) shall be borne by the Government, whereas for outside auditor(s), this shall be borne by the Contractors as a General and Administrative Cost.

**1.9.3** In conducting the audit, the Government or its auditors shall be entitled to examine and verify, at reasonable times, all charges and credits relating to the Contractor's activities under the Contract and all books of account, accounting entries, material records and inventories, vouchers, payrolls, invoices and any other documents, correspondence and records considered necessary by the Governments to audit and verify the charges and credits. The auditors shall also have the right, in connection with such audit, to visit and inspect at reasonable times all sites plants, facilities, warehouses and offices of the Contractors directly or indirectly serving the Petroleum Operations, and to physically examine other property, facilities and stocks used in Petroleum Operations, wherever located and to question personnel associated with those operations. Where the Governments require verification of charges made by an Affiliate, the Governments shall have the rights to obtain certificate from an internationally recognized firm of public accountants acceptable to both the Government and the Contractor, which may be the Contractor's statutory auditors. Submission of the audit certificate shall in no way relieve or diminish the Contractor for the compliance with the obligations under the Contract.

**1.9.4** Any audit exceptions shall be made by the Government in writing and notified to the Contractor within one hundred and twenty (120) days following completion of the audit in question.

**1.9.5** The Contractor shall answer any notice of exception under Section 1.9.4 within one hundred and twenty (120) days of the receipt of such notice. Where the Contractor has, after the said one hundred and twenty (120) days, failed to answer a notice of exception, the exception shall prevail and deemed to have been agreed to by the Contractor.

**1.9.6** All agreed adjustments resulting from an audit and all adjustments required by prevailing exception under Section 1.9.5 shall be promptly

made in the Contractor's accounts and any consequential adjustments to the Government's entitlement to Petroleum shall be made within thirty (30) days there from.

**1.9.7** Notwithstanding any reference to a Sole Expert or Arbitration in accordance with the provisions of the Contract, in case any amount is claimed as due to the Government resulting from the audit exception but not accepted or settle by the Contractor, then the Contractor shall deposit such claimed amount in an escrow account to be opened with a financial institution, failing mutually agreed agreement with State Bank of India within thirty (30) days from the date when the amount is disputed by the Contractor. The amount escrow account along with any interest accumulated thereon shall be appropriated or adjusted in accordance with the decision or award of the Sole Expert or Arbitral Tribunal as may be or otherwise as mutually agreed to between the Parties.

**1.9.8** If the Contractor and the Government are unable to reach final agreements on proposed audit adjustments, either Party may refer any dispute thereon to a sole expert as provided for in the Contract. So long as any issues are outstanding with respect to an audit, the Contractor shall maintain the relevant documents and permit inspection thereof until the issue is resolved.