Report of the Committee

on

Roadmap for Reduction in Import Dependency in Hydrocarbon Sector by 2030

Part I

December, 2013
Acknowledgement

The Ministry of Petroleum & Natural Gas, Government of India, constituted this Committee to prepare a Roadmap for enhancing domestic oil & gas production and sustainable reduction in import dependency by 2030. The Committee was expected to complete this task by the end of November. The Committee met several times to discuss the Terms of Reference (ToRs). It also held discussions with various stakeholders including private and public sector E & P companies, Industry bodies, domain experts etc., before arriving at its recommendations.

During the interactions with various stakeholders, it has become apparent that there are a few issues which, in the Committee’s view, can be prioritized by the Government for early implementation in the immediate future. Accordingly, the Committee has prepared the Part-I of the Report containing recommendations on selected issues, so as to enable the Government to begin work on these recommendations early. The Committee will continue to work on the remaining ToRs and will submit the Final Report in the next few months.

I wish to place on record my sincere thanks to all the Committee Members and special invitees for their contribution in finalizing this report. All the Members, special invitees and stakeholders are renowned experts in their respective fields. The fact that they put in so much of their time and effort shows their commitment to the national cause of energy security. Last but not the least, I would like to place on record my appreciation for the efforts put in by the officers of the Directorate General of Hydrocarbons which enabled the smooth conduct of the proceedings of the Committee. I also convey my thanks to the Boston Consulting Group who have helped the Committee in preparing the Part-I of the Report.

(Dr. Vijay Kelkar)
Chairman
Executive Summary

The Committee felt that given the rather extensive nature of its ToR’s as well as the urgency for taking immediate action, it would be appropriate to give our reports in 2 parts. Part I in December 2013 and Part II in 2014. The Part I includes (i) a discussion of the economic foundations of Exploration and Production Contracts and (ii) an early action program drawn upon our analysis and inputs received from our wide ranging consultations with stakeholders. The Committee believes that these recommendations can be implemented quickly and will yield large near-term as well as longer term gains. These recommendations have been prioritized for consideration and action even as the committee continues to deliberate on the balance topics to complete the onerous task given to it, to its full satisfaction.

The Committee recognizes that for the framing of an appropriate policy for promoting the E&P Sector, it is vital that there is a correct appreciation of the underlying economic and commercial issues. In this the structure of the E&P Contracts gets a central place.

For accelerating E&P activities, the design implementation of production contracts holds a central place. Contractual arrangements have to offer E&P investors the ability to deliver higher than the hurdle rate of return to compensate for the inherent risks, and the right risk-reward balance to invest during exploration, development and production phases to ensure optimal recovery, recognizing the geological attractiveness of the country.

E&P contracts in India have evolved to offer a good risk-reward balance under the PSC framework. The Indian PSC is designed to encourage E&P activity in the interest of enhancing national energy security. The committee analysis shows that under PSC, the interests of the Government are aligned with the interests of the contractors. There is little incentive for the investor (i) to ‘gold-plate’ or (ii) for wilful under-production. Under the PSC, as the investor returns improve, the Government take also increases as it is designed to allow the Government to retain a fair share of the “upside.”

This report includes the following early action measures.

1. Kick start the Open Acreage Licensing Policy (OALP) and accelerate the building of a National Data Repository (NDR) to expedite the appraisal of Indian basins
   I. Adopt the Open Acreage Licensing Policy (OALP) using the existing data repositories of National Oil Companies (NOCs)
   II. Accelerate building of a National Data Repository (NDR)
       • Provide the required funds (estimated to be approximately USD700 million) in a phased manner over five years to collect data for prospective basin areas that are perceived to be of high risk, and that have so far attracted limited or no capital investments
A multi-client speculative survey model and enabling reforms should be formalized and rolled out at the earliest

2. Implement reforms to improve accessibility and transfer of data related to Indian basins
   I. Formulate guidelines for more simplified and seamless modes for data transfer, in line with global best practices
   II. Data residing in the NDR should be used for the OALP as well as for marketing to others

3. Implement reforms in tax policies and administration to ensure that Indian firms are competitive with global counterparts
   I. Tax reforms for domestic operations
      • An income tax holiday should be applicable to all forms of hydrocarbon in line with International best practices
      • A tax holiday for assets where production is inherently slow due to weather (e.g. monsoons) and other logistical issues (e.g. deepwater, ultra deepwater, North East, high temperature high pressure assets) should be extended to 12 years (from the current seven years) from the date of first production
      • Relax social security and provident-fund norms for expatriates to help Indian companies provide oil field services that require expatriate personnel in a cost effective manner and to reduce the expense burden on companies
      • Clarification should be issued reiterating the non-applicability of service tax levied on cash calls made by the operator to other partners in a consortium
      • PSC should be in effect and all conditions applicable as soon as it is signed and not till tabled in Parliament
   II. Tax reforms for international acreage acquisition and operations
      • Reduce the rate of dividend tax paid on income earned internationally by subsidiaries of Indian O&G companies. Under current tax laws in India, the remittance of dividends by an overseas subsidiary to its holding company is effectively taxed at a rate of 16.99% (including surcharge and cess).
      • Revise the tax regime to ensure that Indian firms are not disadvantaged when operating in host countries on production sharing contracts in cases where the host countries do not impose taxes on international players as the underlying PSCs already accounts for the government’s proceeds.

4. Implement reforms related to contract administration of existing Production Sharing Contracts (PSCs)
   Our analysis clearly shows that the current production sharing contracts align both the Government’s Oil Security interests, viz., (i) promote greater exploration efforts to find new fields (ii) maximize production from the existing fields through induction of latest
technology and (iii) obtain a fair share in the “upside” of the project economics and the interests of private sector, i.e., to receive returns commensurate with the underlying risks through the implementation of a stable, fair and transparent contract system. It is also important to recognize that, in principle.

I. ‘Government take’ in the context of Oil and Gas comprises of PEL/ML fees, royalty, cess, corporate tax and profit petroleum share. These collectively form the ‘fiscal interest’ of the government. In principle, the basis for computation of profit petroleum under the PSC is similar to the computation of taxable profit under the Income Tax Act. However, for computation and oversight of corporate tax, which is a part of government take, the government does not get involved in the day to day operations and business decisions of the firm. Given the alignment between the government's and contractors’ interests under the PSC system, prudential and fiduciary oversight of technical dimensions should be afforded more emphasis than the fiscal dimension. Thus, MoPNG/DGH should restrict its involvement only to the prudential and fiduciary oversight of the E&P operator. As provided in the PSCs, the Contractors are expected to adopt Good International Petroleum Industry Practices (GIPiP) while developing discoveries and the DGH should focus on ensuring such adherence. The fiscal dimensions, including computation of profit petroleum, should be under the purview of the revenue authorities.

II. To further enable the DGH to carry out best-in class technical feasibility assessments, the committee recommends the following

- The DGH should have the freedom to employ external agencies for carrying out technical feasibility assessment as required
- Bring the calculation of Profit Petroleum and profit sharing, as stipulated in the PSC, under the purview of the Income Tax Department, under the jurisdiction of MoF

III. Streamline the approval process and bring in transparency

- Standardize the clearance requirements as much as possible by creating a single window clearance system for O&G projects.
- Adopt a concurrent approach for statutory approvals to minimize the total time taken.
- Establish IT based workflow system and move to E-governance.

IV. Establish an inter-ministerial panel to whom the MOPNG may entrust the dispute resolution mechanism for a flexible dispensation depending on the circumstances to ensure timely resolution of issues concerning PSCs

5. Streamline the financial audit process with clearly defined policies

I. Any financial audits relating to PSC should be carried out based on accounting records and financial statements prepared under the provisions of the PSC in
accordance with the Accounting Standards and Audit Standards of the Institute of Chartered Accountants of India (ICAI).

II. The government may conduct the audit through firms of Chartered Accountants or through the Comptroller and Auditor General (CAG), or through international auditors with assistance from management consultants and other experts with relevant experience in auditing oil and gas operations. Such an audit – whether conducted by the CAG or others – should not include performance or efficiency auditing that lies beyond the scope stipulated by the ICAI.

III. In the event of any report of irregularities, the government may determine the need for a forensic or investigative audit in addition to the annual audit.

IV. The government shall make all efforts to complete the audit procedure in accordance with the timelines set out in the Accounting Procedure of PSC.

6. Encourage NOCs to adopt progressive small and marginal fields policies for rapid development of small and marginal fields
   I. NOCs should have the flexibility to bring in an experienced partner for IOR/EOR schemes to ensure implementation of the best practices
   II. NOCs should be allowed to put small and marginal fields out to global tender and form contracts with interested parties for the same purpose
   III. Small and marginal field projects should receive international prices of oil and gas, and not be subjected to contribution towards downstream under recoveries

7. Encourage development of unconventional oil and gas resources
   I. Put in place a policy for private players to permit them to explore shale oil and gas resources under the PSC regime. Current policy permits NOCs to explore shale oil and gas resources from onland blocks that were allotted to them on nomination basis.
   II. Coal India Limited (CIL) should seek to engage with private players and NOCs to develop capabilities in gas extraction, to exploit gas from CBM

8. Reduce the under-recovery burden of upstream oil companies. In principle, the upstream companies should not be required to subsidize under recovery of downstream companies. To make rapid progress towards easing of the under recovery burden of upstream companies, three possible solutions are suggested:
   I. Phase out regulation of diesel and kerosene prices in line with the recommendations of the Parikh committee, which could bring down the overall subsidy burden, thereby reducing the under-recovery of upstream companies
   II. If the government decides against deregulation, it should finance a higher proportion of the subsidies from its own revenue receipts
III. The Parikh committee recommendations should be adopted at the earliest for calculation of under-recoveries

9. Grant the E&P sector benefits similar to those granted to sectors that have been conferred infrastructure status

10. Strengthen DGH to ensure effective sector regulation
   I. OIDB cess should be used to fund strengthening of DGH, as needed
   II. The DGH needs to create an HR pool by hiring the best talents
   III. The DGH should have the freedom to recruit and or deploy international experts at global compensation levels as required

In addition to the early action measures, the tasks that will be completed by the Committee in its final report have been identified in the final chapter of this report.
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Chapter 1

Introduction and Context
1 Introduction and Context

1.1 Context and objective of this report

1.1.1 The Government of India constituted this committee under the chairmanship of Dr. Vijay Kelkar to prepare a roadmap for enhancing domestic production of oil and gas and sustainable reduction in import dependency by 2030.

1.1.2 The constitution of the committee is as follows:

1. Dr. Vijay Kelkar, Chairman
2. Dr. Ashok Ganguly, Member, Rajya Sabha
3. Shri Deepak Parekh, Chairman, HDFC
4. Shri R S Sharma, Ex-CMD, ONGC
5. Shri S V Rao, Ex-Director (Exploration), ONGC
6. Shri Vikram Mehta, Chairman, Brookings India
7. Dr Arindam Bhattacharya, The Boston Consulting Group
8. Shri Ajit Kapadia, Vice Chairman, Centre for Fuel Studies and Research
9. Shri Anil K. Jain, Advisor (Energy), Planning Commission
10. Shri R N Choubey, DG, DGH- Member Secretary

1.1.3 The Terms of Reference (ToR) of the committee are as follows:

1. Steps to be taken for enhancing Oil & Gas production from the unconventional as well as conventional energy sources
2. Institutional mechanism for appraisal of Indian sedimentary basins to the extent of 75% by 2015 and 100% by 2025
3. Utilization of Oil Industry Development Board (OIDB) cess and other innovative resource mobilization approaches for appraising the unexplored/partly explored acreages
4. Development and promotion of Indigenous service industry in E & P sector
5. Review of institutional mechanism to acquire acreages abroad for exploration and production as well as pursuing diplomatic and political initiatives for import of gas from neighboring and other countries with emphasis on transnational gas pipelines
6. Steps to be taken for ensuring adequacy of finances for R & D required for building knowledge infrastructure in E & P activities
7. Steps to be taken for development of gas transportation infrastructure for establishing countrywide marketplace
8. Roadmap for switching over to the market determined gas pricing at the end of 12th plan period
1.1.4 The committee met on 13 March, 9 April, 3 May, 31 May, 20 July, 14 August, 2 September, 5 October, 30 October, 25 November and 13 December 2013 and discussed all the topics that were relevant to its terms of reference. It also invited comments from the public at large. Representatives of E&P companies, industry associations and scholars were also offered an opportunity – in their individual capacity – to present their views to the committee. (Annexure A)

1.1.5 The committee took note of the views expressed and the submissions made before it, and arrived at its recommendations after due deliberation.

1.2 Call to action

1.2.1 The precarious nature of India's energy security, with increasing dependence on imported energy sources, has serious implications for the country. The limitations of domestic energy supplies are being exacerbated by the rapid and dynamic changes in the global hydrocarbon landscape. The Middle East hydrocarbon producers already feel threatened by the energy self-sufficiency scenario of the US and if the 'Arab Spring' becomes a chronic event, it may prolong and threaten the sources and routes for oil and gas imports for India. This continued regional instability and an emerging global energy landscape driven by technology, increases the challenges India faces in achieving energy security. And the pressures are likely to intensify. This means that without radical transformations that see India breaking away from traditional policies and practices, the lack of secure, sustainable energy supplies will have a widespread impact on the country, negatively affecting everything from economic growth and employment to agriculture and food security, and efforts to combat poverty.

1.2.2 There are six different ministries involved in formulating and implementing policies related to energy, thus resulting in coordination issues and lack of a concerted effort towards a national energy policy. Absence of a central executive authority responsible and accountable for the formulation and implementation of energy policy is a structural weakness that needs to be addressed. Given India's current energy landscape, the government's sole purpose must be to develop a national commitment to energy security and articulate an energy policy that would lay out the roadmap for achieving energy independence. The need of the hour is to implement transparent policies and processes that, while safeguarding sovereign rights, also make it attractive for companies to engage in E&P activities in the country.

1.2.3 The Supreme Court has recently reiterated that the country's oil and gas or hydrocarbons reserves are a national patrimony. Consequently, the Government will have to safeguard the owner's interest in designing and implementation of exploration and production policy. These owner's interests have essentially two dimensions, namely (i) "prudential and fiduciary oversight"
dimension, i.e. accelerated exploration and optimal exploitation, development and utilization of country’s exhaustible hydrocarbon resources in an environmentally sustainable manner and (ii) “fiscal” dimension to obtain a fair share in “economic rents” of the underlying natural resources. The Committee is of the view that the primary role of DGH will be to safeguard the owner’s interest in the “prudential and fiduciary oversight” dimension, while the “fiscal” dimension such as collection of royalty, cess, corporate tax and profit petroleum should be the responsibility of the Revenue Authorities.

1.2.4 India currently imports roughly 35% of its primary energy needs. While India imports close to 14% of its coal demand, the figure for oil and gas stand at a staggering 70% and 30% respectively. Today, India imports almost USD150 billion worth of energy. While this is already a serious issue, business as usual forecasts present an even bleaker picture. The US Energy Information Administration (EIA) estimates supply growth of all energy sources in India to be significantly below the rate of demand growth, widening the supply-demand gap to almost 50% of total primary energy demand by 2030. The cost (in current terms) of importing this energy is predicted to reach almost USD300 billion\(^1\) in 2030. If significant measures are not implemented urgently, it is estimated that India will need to import a cumulative amount of energy equivalent to USD3.6 trillion between now and 2030, more than twice the current gross domestic product (GDP). (Annexure C)

1.2.5 While India is not perceived as one of the most resource rich nations, it potentially possesses considerable amounts of hydrocarbon reserves that are largely unexplored and untapped. The 15 basins out of a total 26 sedimentary basins in India have prognosticated hydrocarbon resources of about 206\(^2\) Billion barrels of oil equivalent spread across onland, offshore and deepwater areas. Out of these, till date Hydrocarbon-In-Place volume to the tune of 80 Billion Barrels have been established through exploration activities by the NOCs and Private Companies, leaving behind a significant ‘yet to find’ hydrocarbon resources of about 126 Billion Barrels. Therefore, the need for accelerated and concerted exploration efforts is of utmost importance and should be given top priority by the Government.

1.2.6 Currently, the balance recoverable hydrocarbon reserves in the country are about 15 billion barrels of oil equivalent. However, only for the NOCs (ONGC & OIL), having a large number of mature and ageing fields, the figure is about 11 billion barrels of oil equivalent. To achieve output growth in the near to mid-term, it is critical to focus on (A) producing and mature

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\(^1\) Value for imported oil and gas is taken as USD100 per barrel of oil equivalent, for coal USD20 per barrel of oil equivalent is used

\(^2\) Source: DGH
fields for incremental output (approximately 1.5 to 2 billion BOE incremental production), (B) fields which are discovered but not yet developed (approximately 3 billion BOE) and (C) fields which are under development (less than 1 billion BOE). There is an immediate urgency to focus on all of the above categories of fields and specifically to expedite category C resources, as they offer immediate upside in the country's hydrocarbon production. The introduction of policy and process interventions that will expedite the discovery of new fields and accelerate production of resources that have already been discovered is therefore essential and urgent. If we are able to bring this 6 billion BOE to production over the next 15 years, it would result in ~ $40 billion per year savings in the import bill for the government.

1.2.7 Discussion of India's energy security would not be complete without addressing the role of coal. According to recent EIA estimates, India has 66.8 billion short tons of coal reserves, the fifth largest coal reserves in world. Yet the country faces a growing gap between demand and supply. Accelerated capacity addition in power generation and a decline in domestic coal production have resulted in increased imports of coal over the past few years. While demand has grown by more than 6.5% per year over the past decade, supply grew by a mere 5% resulting in import growth of more than 12% since 2001. Imports accounted for about 14% of total coal demand in 2012. Increasing coal production is fundamental to the goal of energy independence and merits urgent attention at the highest level. Improving the supply growth from the currently anticipated 4% to 5% from 2012-2030 will result in cumulative import savings of USD1.2 trillion during the same period. There is an urgent need to diversify from the policy of monopoly of public sector companies in coal production. Just in the same way as NELP ended ONGC's monopoly in the E&P sector, the time is ripe to formulate a policy to get private sector involvement in coal production in a significant way.

1.2.8 Despite the continuing importance of coal and the contribution of hydropower, nuclear energy and renewable power sources to India's energy security, the committee's recommendations will be limited to the Terms of Reference and focused on the oil and gas sector.

1.3 Approach

1.3.1 To ensure that government actions are aligned with the country's energy security goals, the committee has developed its recommendations guided by the following overarching principles:

- The government's objective should be to enhance energy security and maximise availability of resources to the economy.
Extraction and exploitation of non-renewable energy resources including its pricing should be based on a long-term sustainable strategy that takes into account inter-generational equity.

Any policy and contract between state and interested parties should reflect a balanced risk reward paradigm with due cognizance to India's prospectivity and materiality.

Clear and transparent sector governance and contract sanctity are essential in order to guarantee sustained investment interest in the sector.

Technology and adequate infrastructure are the sine qua non for the accelerated and sustainable development of the sector.
Chapter 2

'Centrality' of E&P contracts for Development of Oil and Gas Sector
2 'Centrality' of E&P contracts for Development of Oil and Gas Sector

Exploration and production (E&P) of oil and gas is an inherently risky business and needs an appropriate balance of risks and rewards to attract private capital. Higher the risk perceived by the investor in terms of country risk including contractual and legal track record, geology risk (e.g. ultra deep sea more risky than land) and level of prospectivity and data availability, higher is his reward threshold for investment. At the same time, the contractual framework needs to be designed to deliver the Government's policy objective of promoting national energy security in a competitive manner.

Selecting and designing the 'right' contractual model that keeps the country specific risk profile as perceived by private capital needs to be given serious consideration. Terms need to be offered that balance these risks with the rewards for the operator, while meeting the government objective of promoting national energy security by reducing import dependency. Thus this aspect remains central to the terms of reference set for the committee.

2.1 Current Situation on the Contractual Model

Production Sharing Contracts have provided the framework for exploration and production contracts between the Government and the Petroleum Companies for now nearly 2 decades. They were the basis for the contracts signed under the Pre NELP regime and then from 2000 they defined the framework for NELP. The two major discoveries in the Barmer basin of Rajasthan and the Krishna Godavari basin offshore East India were appraised, developed and put into production under this contract framework. All issues related to these discoveries including pricing and sales were handled competently by the administrative machinery of the management committee, the DGH and the MOPNG.

In 2007/08 there was debate and controversy over the price and allocation of the gas produced from KG D6 basin. Issues also arose over the terms of the PSC contract, capex, provisions of cost recovery and government take. The Government stepped in to resolve these issues and in 2008/9 it asked the CAG to carry out an audit of all the NELP blocks. The request was for a limited audit but the CAG reviewed all of the above issues for NELP blocks and also covered the discovered fields.

The CAG report accepted the role of the DGH as the regulatory custodian of all technical issues but at the same time it drew attention to several technical issues. It also focused on issues such as the procurement of technology and equipment, performance of the gas fields, gas price, gas utilisation, gold plating and government take. The CAG report triggered debate and discussion on the interface between the Government and the Contractor and also on provisions of the PSC such as Cost recovery and profit oil/gas.
The PSC format is a widely accepted contract model for balancing the risks of exploration with potential rewards. It was adopted by India in the late 90’s after a survey of alternative contract models and due consideration of India’s geologic prospectively and the need to accelerate the pace of exploration. It was adopted as the most effective model for encouraging investment in the countries high risk and geologically complex sedimentary basins. The contract framework has worked well for years and to an extent it has met its objective. The pace of exploration has intensified. However in recent years the PSC has come into the Public eye because of the controversies related to the KGD6 basin and the CAG report.

The PSC has worked smoothly for many years. The CAG has also given an audit endorsement for the Rajasthan contract and other PSCs. Whilst this does not mean that there is no requirement to review the terms to ensure they are competitive, given the evolving nature of business, public policy and technology, or that its administration must not be streamlined, however it does mean that one must not over react and undertake regressive measures to replace the contractual philosophy that has worked well for so many years simply because of certain disputes or the comments raised by the non technical CAG. The Committee felt that it is necessary to clear the miasma that now surrounds the E&P contracts in India as this has proved detrimental to our efforts to enhance country’s oil security. Hence, in this chapter we have provided deeper analysis of the economic issues assailing our current PSC System. This discussion aims to help choose wisely our policy approach towards exploration and production contracts.

The controversy over the KG Basin contracts has been fuelled by two ‘perceptions’ resulting from falling gas production:

1. The operator has ‘gold plated’ expenses to recover costs despite falling production
2. The operator has willfully under-produced for his future economic benefit

These perceptions have not just vitiated the environment of policy making and implementation but also vitiated the public discourse in the sector; they have called into question the choice of the current contractual model of PSCs and led to the selection of Revenue Sharing Model (RSM) as the model going forward.

Both these models and several others like PRRT (Petroleum rent rate tax) as prevalent in Australia, Windfall tax model as seen in countries like Venezuela, Columbia are legitimate E&P models adopted by different countries and come with their pros and cons. In this chapter we do NOT get into recommending the ‘right’ contractual model for India keeping in view the three criteria of (i) risk reward for the private capital, (ii) administrative challenges of implementing contracts and (iii) government objectives of energy security and reducing import dependency. The committee will do this in Part 2 of its report. We will limit the discussion to four specific themes/issues which will shape the recommendations both in Part 1 and 2 of this report:
2.2 Role of contracts in Effective Risk Management in E&P

E&P contracts are risk sharing contracts and their design reflects the risk inherent in the E&P business, where most variables that determine the production and returns from a reservoir are outside the control of the investors. A productive reservoir needs the confluence of probabilistic and variable geologic factors: a seal so that fluids cannot escape, enough thickness, areal extent and porosity to hold sufficient hydrocarbons and permeability so that hydrocarbons flow at an acceptable rate. Further, to develop such a reservoir needs access to technology and capital, ability to source and combine various equipment and services, and ability to manage the operations of this system.

Figure 1: Average government take for exporting countries

The government’s choice of a contract to offer to investors typically reflects the geologic risk-commercial return balance that would ensure investments to flow into the sector. Some of the most onerous contract choices and terms are made by hydrocarbon exporting countries (such as OPEC and major gas exporters); here the host governments have the confidence that investment
and technology will flow in to the sector. Hence, as shown in Figure 1, the average government take in exporting countries is 71%.

As a corollary, countries which are largely unexplored or have poorer geology (and hence are hydrocarbon importers), tend to offer contractual structures which offset the high geologic risk. In such countries, if this risk-reward balance is adversely altered, investment flow will inevitably decline. Tough contract terms with high geologic risk are a non-starter to increase production, especially for a hydrocarbon importing country. Hence, as shown in Figure 2, the average government take in importing countries is 52%, compared to the exporting country average of 71%.

*Figure 2: Average government take for importing countries*

**Exploration for hydrocarbons is a high risk activity with a recent track record in India of 1 in 10 exploration wells being successful. Further, activity in deepwater where most of India’s prospectivity lies is expensive with well costs between $80 to $120m. The investor also does not know with certainty whether the successful well will yield oil or gas and the size of the reservoir and its materiality.**
Figure 3 is a representation of the uncertainty around recoverable resources as a field progresses through its life cycle from exploration through to production. Typically, the range of uncertainty around the recoverable resources reduces but does not disappear as a field is appraised and developed. This uncertainty can result in unexpected production declines; some examples are listed below:

- **Ladyfern in Canada**: Despite the development being projected as a game changer for Canadian gas supplies, the field saw 96% decline in 8 years with the highest, unexpected declines in the first 2-3 years.
- **Bijupira-Salema in Brazil**: Peak production levels of 70 mb/d in 2004 did not materialize; actual production reached 40.5 mb/d in December 2004.
- **Golfinho in Brazil**: Actual production of 55 mb/d against an expected peak of 175 mb/d.
- **Seven Heads in GOM**: Actual production of 20 mmcf/d, against expected levels of 100 mmcf/d.
- **Neelam in India**: Actual production of 33 mb/d, against expected production of 90 mb/d.
- **Imperial Energy in Russia**: 15 mb/d of production against targeted production of 80 mb/d.

On the converse, there are several examples of increases in production and recoverable reserves globally besides India fields in Upper Assam and Gujarat:

- **Rokan in Indonesia**: PSC framework encouraged the world’s largest steam flood project with resultant recovery factors of ~50% compared to primary recovery factors of 5-10%.
• **Ghawar in Saudi Arabia**: This field accounts for 5-6% of world oil production with production rates of ~5 million b/d and ultimate recovery of ~75% has been based on technologies such as smart well systems, maximum reservoir contact wells, and high resolution reservoir simulation models and start of CO₂ injection in 2013

• **Prudhoe Bay in UK**: Additional exploration within the area helps in sustaining the production through new discoveries which utilise existing infrastructure. Recovery factors have increased from 30% to close to 50% since the 1970s due to application of enhanced oil recovery techniques and 4D seismic technologies.

• **Upper Zakum in UAE**: Development based on attracting foreign investment to achieve a targeted recovery factor of 70%

Advanced technological inputs and additional capital is often required during the production phase to ensure that recovery from a reservoir is optimised. It should also be noted that unlike their counterparts in other industries, due to unique nature of O&G sector, players face risk at both production and price fronts. Given these inherent risks persist through the life of a field, contractual arrangements have to offer E&P investors the ability to receive returns higher than the hurdle rate of return to compensate for these risks and the right risk-reward balance to invest during exploration, development and production phases to ensure optimal recovery.

2.3 **Are contractors incentivized to 'gold-plate' in PSC environment?**

Technically, ‘gold-plating’ is defined as spending additional capital or resources than required to produce the hydrocarbons. Gold-plating is different than accounting fraud (e.g. over/ under invoicing) – these are monitored through accounting audits and corporate tax compliance reviews, and investors found guilty of engaging in such malpractices should not be allowed to participate in the E&P activity set. In the Indian context, gold-plating is a concern in a cost-plus regime (seen in sectors such as fertilizer and power). Typically, an administered price regime for Fertilizer, Power Sector, etc., provides an assured rate of return on the capital employed. Such an assured rate of return tends to be higher than the market rate and thus providing an incentive for “gold-plating” as even a firm not minimizing capital cost can still get rewarded! But, this hardly is the case with the PSC where neither rate of return on capital employed is assured nor the output price as the price of oil or gas is linked to relevant international price.

The assumption that contractors in a PSC framework would not exercise cost discipline as they were assured cost recovery is not incentive-compatible as every dollar of unwarranted expenditure would need to be recovered from the project revenues, and which adversely impacts contractor returns.

An analysis of a typical Indian gas field under a PSC framework across a range of capital outcomes (Figure 4) shows that as the capital expenditure increases the NPV for both the investor and the government falls, but it falls more rapidly for the investor. As the investor puts up
the risk capital upfront, he is not incentivized to gold-plate and it is in his interest to minimize capital spend across all stages of field life.

At the highest stage of risk in the exploration phase, a contractor invests highest cost equity capital and would never overinvest or drill unnecessary, un-optimized wells. During the development or production stage, the investor is putting up large amounts of risk capital and as can be seen above has a disincentive to overinvest. The contractor does not have an incentive to gold plate as, for any given capital structure, higher the risk-adjusted capex, lower the returns for the contractor group.

Further, under NELP, a contractor arrives at the key terms of the PSC, via global competitive bidding. At the time of the bid, the investor has to take the risk of the price, costs and volumes – none of which are known with certainty leading to a high level of uncertainty on the profits. **In such a transparent process, any investor who assumes ‘gold-plating’ in his bid would not be able to offer competitive terms and will ab-initio not win. Hence there is no incentive for a profit maximising firm to gold-plate under a PSC framework.**

### 2.4 Willful under-production by O&G operators

One of the concerns related to the administration and oversight of PSC contracts is the possibility of O&G operators wilfully under-producing. The government is particularly apprehensive of under-production by O&G players as India imports a large share of O&G demand, and any such under-production would consequently impact the trade balance and CAD (current account
deficit). A rational assessment of the O&G environment in the country, along with the risk-return associated with under-production for the investor, indicates very limited economic rationale or incentive for the operator to indulge in such wilful acts on a going basis.

In fact, quite contrary to the risk of under-production, at most time the focus of governments is to ensure the operators do not engage in ‘flogging’ of wells to extract more resources early. Thus the adherence to GIPIP, which optimizes the extraction of underlying resources over the long term keeping in mind reservoir well being, are enforced to keep such ‘over-production’ in check.

Key factors which undermine the possibility of wilful under-production:

Volatility in oil prices:

As shown in Figure 5, historically the price of oil has been known to be highly volatile and unpredictable. Oil prices are influenced by multiple factors including commodity price speculation, world demand, geological limitations on increasing production, OPEC monopoly pricing, political developments in major oil producing companies and trade dynamics. Past research has been unable to predict future trends with any real certainty. Thus, for an operator to defer production on account of a viewpoint on future prices is fraught with excessive speculative risks.

It should also be noted that even if the operators were certain about their prediction regarding future crude prices, they would stand to gain more by taking positions in the financial market rather than changing the production schedule at producing fields.

**Figure 5: Monthly spot prices for crude oil for last 13 years**

<table>
<thead>
<tr>
<th>Dollar per barrel</th>
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<tr>
<td>150</td>
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<tr>
<td>100</td>
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<tr>
<td>50</td>
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Brent spot price
WTI spot price
Technical feasibility of higher production from existing fields

DGH approves a Field Development Plan (FDP) before actual production starts on any oil and gas field. An FDP is made on the basis of extensive study based on GIPIP and specific reservoir characteristics, flow rates to achieve optimal production over the long term. The actual production of each field is expected to be in line with the “declared” schedule. Limited flexibility is afforded to the operator over the expected production levels from the reservoir. Any adjournment of production can thus only be carried out to a limited extent on the basis of the pre-determined capacity of the field to produce beyond anticipated production levels. Thus the ability of an operator to wilfully under-produce at a given time and compensate for that through higher than anticipated production at a later time is technically limited. Given also the fact that the operator cannot go beyond contract period, such an action seems even less attractive.

Time value of deferred production

The graphs in Figure 6 and 7 represent indicative returns to an operator in the case of deferred revenue through wilful under-production. The case shows that even in an assured high price future scenario where prices increase by 50% after 10 years, the net return in terms of incremental NPV to investor through wilful under-production is negative. NPV has been considered as a parameter for evaluation as it is more appropriate than comparison of only absolute sum of profits across years. Let us take an illustrative case of a field producing 10kboe/day in steady state. We have considered two scenarios

1. Operators have no flexibility over projected production levels
2. Operators have 10-15% upside production flexibility on projected production levels

Under both the scenarios, if the production is deferred by 50% (i.e. only 5kboe/day) and we assume a 90% upside on the future price, the time value of money ensures a reduced NPV vis-à-vis “normal production” for the operator.

In scenario 1, given that Field Development Plans (FDPs) are designed in line with the expected level of production from a given reservoir, any under-production in the initial years can only be recovered towards the end of the field life, once the normal production level declines and frees up capacity. Figure-6 illustrates this point for a typical field, where the operator under-produces in the initial years and in return, is able to extend the ‘plateau’ of production profile in the later years. As can be seen, the financial impact of this under-production is significantly negative to the operator and rules out any incentive to under-produce. As shown in Figure 6, for a medium sized field (10 kboe/ day) the net down-side due to under-production to an investor amounts to ~80 million USD. With larger field sizes and production volumes, the losses would be of even higher magnitudes.
Thus, given the constraints on field characteristics as frozen at the time of FDP, the volatility of oil prices, and the inability of any operator to predict future rates with any certainty, the economic rationale for willful under-production is highly questionable.

**Figure 6: NPV comparison for normal & deferred production schedule assuming no flexibility**

![Figure 6](image1)

**Figure 7: NPV comparison for normal & deferred production schedule assuming 15% flexibility**

![Figure 7](image2)
2.5 Economic Analysis of PSCs and RSMs for both government and Operators

As articulated in several policy documents, to achieve energy security, it is important to

- Maximise Risk Capital to explore all potential resources
- Accelerate optimal development of discovered resources
- Optimise production and maximise recovery from discovered resources

The Government is seeking to move away from the current PSC mechanism to a Revenue Share mechanism linked to production and price for future E&P blocks. While several arguments have been presented for and against this recommendation, this move needs to be carefully evaluated on the likelihood of maximizing production, government revenues and risk capital.

Two different approaches were followed to create a 'real world' simulation comparing the new revenue share model and PSC model to understand the impact of the two models on three key parameters – Total production, Government revenues and Risk capital.

The committee thanks AOGO and BCG for sharing with the committee the workings of the detailed monte carlo simulation of Indian basins and data related to 1132 fields respectively. The analysis of the data and the findings are however carried out by the committee itself. All the related data for the analysis is available with the DGH for any further review and subsequent analysis as required.

**Approach A**

Probabilistic economic modeling (Monte Carlo simulation) was conducted on a broad based dataset of 20,000 fields covering the range of operating environments from the easiest (onshore oil and gas) to the most difficult (deep water oil and gas). A representative field distribution curve was attributed for each operating environments with representative cost and production profile assumptions used to arrive at an estimate of project, government and contractor value. Gas prices assumed were as per the Rangarajan Committee formula and oil prices close to current levels at $100/bbl. Further, it is assumed that higher volumes and project materiality leads to economies of scale. The detailed assumptions are listed in the (Annexure B). The results of the Monte Carlo simulation on the above parameters are as follows:
I. Implications for production efforts

Developing projects based on Revenue Share regime would require of higher Minimum Economic Volumes across all operating environments, from the easiest (onshore) to the most difficult (deep water), as shown in Figure 8. In effect, this could lead to larger number of fields to remain unexplored. Since the risk-reward balance would be more skewed under a Revenue Share as compared to a PSC, operators will need greater volumes to make the case for exploratory risk in Indian basins, and hence would need a higher minimum economic threshold of production to develop reserves. This behavior, when aggregated across all Indian basins, will lead to several fields remaining undeveloped. Hence production levels would be minimized under the Revenue Share regime (as compared to the PSC regime), leading to lesser energy security and hence, greater import dependence with further negative implications on macroeconomic parameters (current account deficit, fiscal deficit and exchange rates).
Further, for oilfields where operating cost intensive enhanced oil recovery (EOR) could add significant recoverable reserves, PSC regime provides stability and incentivizes EOR across varying field sizes (as shown in Figure 9, from 100 – 500 mmbbls). Revenue Share regime on the other hand, would fail to provide incentives for EOR (typical operating cost of $20/bbl in India) even at higher reserves.

Based on the analysis presented in case of undeveloped fields (in Figure 8) and developed, mature fields (in Figure 9), Revenue Share regime would lead to hydrocarbons remaining undeveloped and unproduced as the minimum economic thresholds are higher under the Revenue Share regime and high expenditure, material projects for EOR would negatively impact contractor project value. This would inevitably lead to a natural selection away from projects across operating environments and thereby, adversely impact government’s energy security objectives.

As there will be low levels of exploratory efforts to locate and produce from smaller fields, and also lower overall production levels across fields, it will not encourage fully the use of new technologies for enhanced oil recovery.
II. Impact on Government revenues

While revenue maximization is not the overwhelming criteria for an energy importing country, even on this objective, the PSC scores higher as by design project revenue upside goes to the government. As shown in Figure 10, Expected Government revenues are consistently higher across all operating environments, in a PSC as opposed to a Revenue Share. This is a corollary to the adverse impact on project selection and production, as more fields are incentivized to come onstream and enhance field recovery under the PSC regime.

Expected Government revenues are defined as the probability weighted average Government NPV₈ for reserve sizes above economic volume.
Further, the PSC is a more stable regime for government revenues in case there are changes from the “as bid” scenario. Post bidding, due to the probabilistic nature of the E&P business, there are invariably changes in reservoir understanding and/or costs which would translate into a +/- 30% impact on capital expenditures. As shown in Figure 11, across all operating environments, under this real world scenario of a movement away from bid assumptions, the PSC regime remains robust and government revenues are still higher or similar to those under the Revenue Share case. The Government also retains more of the upside in case of a reduction in capex due to the design of the PSC which enhances the stability of the contract.

III. Ability to Attract Risk capital

Figure 12: Changes from bid scenario: Impact on Minimum Economic Volume (MEV)
While the contractor faces higher minimum economic volumes as a threshold to invest, given the probabilistic nature of the E&P business, the risk-reward balance becomes more adverse for a contractor under the Revenue Share regime. In case there are adverse changes from the ‘as-bid scenario’, for example, the reservoir properties are poorer (difficult to predict at the bid stage even with modern/best technology), then the gap in minimum economic volumes between Revenue Share and PSC would increase. This would imply that contractor will face even more difficult economics under scenario of adverse changes (reservoir properties, market conditions etc.). Most contractors will factor this at the exploration stage or the bidding stage, and not invest. This would inevitably filter out significant risk capital, in favour of countries where the risk-reward balance is not as skewed and which offers the prospect for better returns, given similar field sizes and investment levels. With risk capital disincentivized to enter India, Indian basins run the heightened risk of remaining under-explored.

**Approach B**

The two contractual regimes PSC and revenue share are run through actual 1132 oil and gas fields in Indian basins for different price scenarios. The data is as per the Rystad global database, and also includes forecast data on fields which are currently not discovered. Hence the number of fields far exceeds the current count of fields under production in the country. Goal seek is done to identify the optimal parameters across the two contractual regimes for a constant government take. The cash flow per field is calculated to compare the impact on net present value (NPV) of government take and on net present value (NPV) of the investor take under PSC and revenue share. Field with negative NPV for investors clearly demonstrates low investor interest. The detailed assumptions are listed in Annexure B. The results of the simulation on actual fields on the above parameters are as follows:

*Figure 13: With similar government take, PSC would lead to an additional ~7 bn boe production with +ve NPV compared to rev share*
Developing projects on PSC regime would result in additional 7 billion BOE of production from positive NPV fields for investors compared to the revenue regime as shown in Figure 13. Evenly spreading out the 7 billion BOE over the next 80 years results in additional ~ 250 kbd of production, which is approximately 22% of the current production. If India had prolific hydrocarbon reserves then the production from fields with positive net present value would be comparable under the two regimes. However since most of India's undiscovered reserves lie in difficult terrain, the inherent risk is higher. The PSC regime is able to incentivize more investors which is seen by higher total NPV.

**Figure 14: Under all price scenarios, PSC maintains its dominance over revenue share**

The simulation is run under different price scenarios. The cumulative average growth rate (CAGR) for price increase from 2013-2100 is varied from 0%-6%. As per EIA, under the base price the oil price should grow at CAGR of 3%. This is close to the inflation rate (~2.5%) which is used to adjust the capital expenditure and operating expenditure over the years. Under all the price scenarios, PSC has higher production from fields with positive NPV compared to Revenue Share as shown in Figure 14.

**Conclusions**

Contractual arrangements have to offer E&P investors the ability to deliver higher than the hurdle rate of return to compensate for the inherent risks and the right risk-reward balance to invest during exploration, development and production phases to ensure optimal recovery, recognising the geological attractiveness of the country.

E&P contracts in India have evolved to offer a good risk-reward balance under the PSC framework. The analysis presented in this chapter shows that there is no incentive for the investor to ‘gold-plate’, and the interests of the investors under a PSC are aligned with the
Government. The PSC is designed to encourage E&P activity in the interest of promoting national energy security. As the investor returns improve under a PSC, the Government take increases with enhanced stability of the contractual regime, given it is designed to allow the Government to retain more of the upside.

Based on the simulation analysis undertaken of comparing the PSC and Revenue Share regimes, under similar bidding behavior by contractors, the PSC system appears to be the better regime to maximize production, government revenues and committed risk capital. The interest of both the Government and Contractor is fully aligned with Government getting a larger share in case of any upside, while sharing some amount of risk post production. Under the Revenue Share framework, the interests of the investor are not fully aligned with the Government, with the investor not likely to invest to optimise recovery from a field under some conditions. Further, as the upside is retained by the investor the contractual regime may be less stable in times of ‘windfall’ gains.

For India, which is currently only about 22% ‘medium-to-well’ explored and which is facing a rising energy import bill, the design of managing the hydrocarbon sector contracts should be chosen by the objectives that are required to be met. It is only if India attracts sufficient risk capital and production is maximized, that there is any chance of delivering the government’s energy security objective.

**Recommendations**

The committee feels that given the specific context of India (mentioned several times earlier) it is possible to improve on the PSC regime by replacing it with a tax and royalty type regime provided it is accompanied with a well designed mechanism of imposing “super profit tax” in addition to the normal corporate tax and making the “super profit tax” rate a biddable parameter. Such a framework will be necessary in order to (i) give the Government an equitable access to any “upside gains” of the project, (ii) provide contract stability by avoiding the “time-inconsistency” problem and (iii) further simplify implementation of the E & P contracts. There is a need to study this further so as to explore in-depth various possible mechanisms (Part 2 of the report).

Committee recommends that till any new contractual model is implemented, the current PSC model be further strengthened by both refining the decision criteria to eliminate some of the roadblocks and the simplifying procedures followed in its implementation. Further, the appropriate oversight on government's interest may be possible by prescribing a robust set of guidelines, checklists and accountability along with prudential and fiduciary oversight of the E&P operations. This is covered in the next chapter on 'early action measures'
Chapter 3

Early Action Measures
3 Early Action Measures

3.1 Policies to expedite the appraisal of Indian basins

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<tr>
<th>Recommendations of the Committee</th>
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<tr>
<td>1. Adopt the Open Acreage Licensing Policy (OALP) using the existing data repositories of National Oil Companies (NOCs)</td>
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<td>2. Accelerate building of a National Data Repository (NDR)</td>
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<tr>
<td>• Provide the required funds (estimated to be approximately USD700 million) in a phased manner over five years to collect data for prospective basin areas that are perceived to be of high risk, and that have so far attracted limited or no capital investments</td>
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<tr>
<td>• A multi-client speculative model and enabling reforms should be formalized and rolled out as soon as possible</td>
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3.1.1 Initiating the Open Acreage Licensing Policy (OALP) is a crucial step in accelerating production from domestic resources. As seen elsewhere, with Colombia being a prominent example, a well-administered OALP can be the key to attracting investor interest in basins that have historically enjoyed limited success. Given the successive drop in investor interest across the later New Exploration Licensing Policies (NELPs), it is therefore imperative for India to pursue urgently the launch of the OALP in a planned manner. During the transition phase OALP can run in parallel with NELP as we phase out NELP. At the same time, the committee does not see any reason to delay the launch of OALP, or to link the launch to completion of other ongoing initiatives such as the NDR. The committee strongly suggests launching the OALP immediately using the data available from NOC's till the National Data Repository (NDR) becomes fully operational.

3.1.1.1 The following are the proposed outline features of the OALP:

- Acreages for the exploration and production (E&P) of hydrocarbons should be on offer throughout the year.
- The sedimentary area, which is presently not under E&P activity, should be offered for open acreage. The area already under Mining Lease (ML), Petroleum Exploration License (PEL) and NELP-X (the tenth round of NELP) should be excluded from open acreage offer. Bidders should be able to choose the size and shape of the area before bidding. The government should divide Indian territory (the land area up to the international
boundary and the offshore area up to the Exclusive Economic Zone, or EEZ) into small zones and sectors that will form the basic units for bidding.

- Companies interested in a particular area could approach the government of India (GOI) to seek a grant for an exploration license for that area.
- The periodicity of opening OALP bids could initially be six months, which would give bidders enough time to select the OALP area and prepare their bids. This periodicity should be regularly reviewed based on the response/interest of the bidders.

3.1.2 A large proportion of India's undiscovered resources lie in difficult terrains such as frontier onland areas and ultra-deep water areas. This increases the business risk for the industry. The quality of most of the decisions taken by E&P companies depends directly upon the availability of sufficient and reliable data. Hence, good quality data is needed to reduce the business risks associated with exploration and to encourage more investors to explore Indian sedimentary basins. Completion of a world-class National Data Repository (NDR) is therefore a vital step in improving the rate of appraisal growth in India.

3.1.2.1 Given the importance of the NDR, the committee recommends that in order to accelerate the process of developing the repository, the following actions should be taken immediately:

- A large amount of data on relinquished fields that have not been re-awarded resides with operators such as the ONGC and OIL, and this should be made available to the NDR for the use of interested parties.
- The NOC's can be provided specifics of each acreage so that data packages and all G&G data are prepared by the NOC's to enable loading of the same.
- Existing non-proprietary data with private players should also be made available to the NDR for future use.

- The government should promotes multi-client speculative surveys and introduce reforms so that providing data to the NDR becomes a more attractive proposition for companies.
  - Any participating company should be given sufficient exclusivity period for its data, in line with global best practices, to enable it to benefit from data sales.
  - The government should play no role in determining the price for the sale of the data to interested third parties or in approving funding for exploration. The reforms proposed are in line with those suggested by the Directorate General of Hydrocarbons (DGH).

- Provide the required funds (estimated to be approximately USD700 million) in a phased manner over five years to collect data for prospective basin areas that are perceived to be of high risk, and that have so far attracted limited or no capital investments.
3.2 Reforms to improve accessibility and transfer of data related to Indian basins

**Recommendations of the Committee**

1. Formulate guidelines for more simplified and seamless modes for data transfer, in line with global best practices
2. Data residing in the NDR should be used for the OALP as well as for marketing to others

3.2.1 As greater proportions of Indian basins are appraised, aided by new and modern technologies, the amount of information generated is expected to be significant. However, the storage and transfer of such information by ministries, operators and others remains outdated. While ensuring the security of data is critical, the time and effort required for even basic transfer of important information is substantial. Unless urgent measures are taken to streamline the process of data sharing, this burden is likely to increase. The government should formulate clear guidelines for simplified and seamless data transfer using new technologies, while maintaining data security, given the sensitivity of this data. Well-tested methods, such as the Secure File Transfer Protocol (SFTP), could be considered and rolled out.

3.2.2 Beyond the use of Indian basin data for the purposes of the NDR and the OALP, it is also imperative for the government to use this data to market Indian prospects. Marketing initiatives could be targeted to research institutes, technical and industry bodies and other relevant entities. Such initiatives would not only help to create greater awareness of Indian basins, but also foster greater interest and analysis of Indian prospects. The government should therefore establish policies and guidelines for the sharing of Indian basin data.

3.3 Reforms in tax policy and administration

**Recommendations of the Committee**

1. Tax reforms for domestic operations
   - An income tax holiday should be applicable on all forms of hydrocarbon in line with International best practices
   - A tax holiday for assets where production is inherently slow due to weather, monsoon and other logistical issues (e.g. deepwater, ultra deepwater, North –East, high temperature high pressure assets) should be extended to 12 years (from the current seven years) from the date of first production
Recommendations of the Committee

- Relax social security and provident-fund norms for expatriates to help Indian companies provide oil field services in a cost effective manner and to reduce the expense burden on companies.
- Clarification should be issued reiterating the non applicability of service tax on cash calls made by operator to other partners in a consortium.
- Allow companies to avail tax benefits as soon as Production Sharing Contract (PSC) is signed with the government. Under the current practice tax benefits come into effect only after the contract is tabled in parliament.

2. Tax reforms for international acreage acquisition and operations

- Reduce the rate of dividend tax paid on income earned internationally by subsidiaries of India O&G firm. Under current tax laws in India, the remittance of dividends by an overseas subsidiary to its holding company is effectively taxed at a rate of 16.99% (including surcharge and cess).
- Revise the tax regime to ensure that Indian firms are not disadvantaged when operating in host countries on production sharing contracts where host countries do not impose taxes on international players but underlying PSCs already account for the government’s proceedings.

3.3.1 Tax reforms for domestic operations

3.3.1.1 Whether a company discovers oil or gas is a function of geology, and the services cost structures to explore and develop both are almost the same. When inviting bids as well, the work program commitments or production sharing bid for by a Contractor are the same whether there is an oil or a gas discovery. The definition of ‘mineral oil’ as provided under various provisions of the Income-Tax Act, 1961 and statutes governing petroleum sectors – Oilfields (Regulation and Development) Act, Oil Industry (Development) Act – includes petroleum and natural gas. The recent amendment to Section 80-IB (9) of the Income Tax Act includes tax holiday to commercial production of mineral oil and natural gas from O&G blocks awarded under NELP VIII. However, the amendment continues to prevent companies engaged in commercial production of coal-bed methane from enjoying similar tax holidays. The committee strongly recommends that the income tax holiday be applicable on all forms of hydrocarbons. The committee also recommends that the spirit of the fiscal stability clause – in terms of the tax holiday under section 80-IB (9) of the Income Tax Act – be maintained for all blocks bid under the entire NELP/unconventional regime, irrespective of the form of hydrocarbon. This will be a crucial step in bolstering investor confidence and interest in Indian basins.
3.3.1.2 Certain deepwater offshore blocks along the eastern and western coastlines of India are believed to have high prospectivity and many global players have shown interest in exploring these blocks. However, due to logistical challenges and complexities, exploration costs for these blocks are extremely high. Hence, it is recommended that the tax holiday for these assets be extended to 12 years (from the current seven years), starting from production commencement date.

3.3.1.3 Indian companies have to hire expatriate on project basis due to skill shortage within the country. Under Indian Government social security norms, Provident Fund needs to be deducted from both employers and employees. Since expatriates come generally on a project basis and are not available to benefit from the provision, Indian companies bear an extra cost on account of employee’s contribution as well to retain expatriates for seamless execution of projects, ultimately increasing the project cost. It is suggested PF norms could be done away with to reduce the extra cost burden. Relaxed social security norms and provident-fund norms for expatriates will help Indian companies to provide oil field services in a cost effective manner and will reduce the expense burden on companies.

3.3.1.4 The activities performed under the E&P sector are highly technical, capital intensive and bear a high degree of commercial risk. In order to share the financial and technological burden of undertaking exploration activities, as well as better manage the risks, companies frequently bid for these projects under a consortium. One of the members is appointed as the operator to manage and carry out joint activities on behalf of the consortium. The cost of joint activities is to be borne by the members in the proportion of their participating interest. The operator carries out all the operating costs. However for the cost relating to the other members of the consortium, the operator makes a request for cash from such members (i.e. cash calls). There are various reasons to conclude that service tax should not be applicable on these cash calls made by the operator on other members of the consortium. One of the key requirements of the definition of the term “service” is that service should be provided by one person to another. As per the clauses of PSC, the operator does not render any service to any other person. The transaction amounts to pooling of resources by different persons who have agreed to come together to share the business risks and rewards. The operator is merely a focal point for communication between the government and the consortium. There is complete absence of service receiver and service provider relationship. The committee strongly recommends that government should reiterate the non applicability of service tax on such transactions.

3.3.1.5 The tax benefits related to PSCs become available to operators only after the contracts are tabled in parliament. However, tabling in parliament is a cumbersome and time consuming process. Government should ensure that tax benefits are allowed once the O&G firms enter into Production Sharing Contract with the government.
3.3.2 Tax reforms for international operations

3.3.2.1 Given the limited nature of India's oil and gas reserves, acquisition of international assets is one of the most critical elements of the country’s energy security agenda. It is imperative for the government to revise India's tax laws to encourage outbound investments in the O&G sector. In particular, policymakers need to ensure that Indian firms are not disadvantaged when the tax regime in host countries has a different structure from that of India.

3.3.2.2 It is therefore suggested that for E&P initiatives undertaken overseas the territorial principle of taxation should be followed. Under current tax laws in India, the remittance of dividends by an overseas subsidiary to its holding company is effectively taxed at a rate of 16.99% (including surcharge and cess). The government needs to reduce the rate of dividend tax so that Indian firms can successfully compete with foreign players. Furthermore, tax rules need to be modified so that Indian firms are not disadvantaged when operating in host countries through production sharing contracts in cases where host countries do not impose taxes on international players but underlying production sharing contracts (PSCs) already account for the government’s proceedings.

3.4 Reforms related to contract administration of existing production sharing contracts (PSCs)

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<th>Recommendations of the Committee</th>
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<tr>
<td>1. 'Government take' in the context of Oil and Gas comprises of royalty, cess, corporate tax, and profit petroleum share. These collectively form the 'fiscal interest' of the government. In principle, the basis for computation of profit petroleum under the PSC is similar to the computation of taxable profit under the Income Tax Act. However, for computation and oversight of corporate tax, which is a part of government take, the government does not get involved in the day to day operations and business decisions of the firm. Given the alignment between the government's and contractor's interest under the PSC system, prudential and fiduciary oversight of technical dimensions should be afforded more emphasis than the fiscal dimension. Thus, MoPNG/DGH should restrict its involvement only to the prudential and fiduciary oversight of the E&amp;P operator. As provided in the PSCs, the Contractors are expected to adopt Good International Petroleum Industry Practices (GIPIP) while developing discoveries and the DGH should focus on ensuring such adherence. The fiscal dimensions, including computation of profit petroleum, should be under the purview of the revenue authorities.</td>
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</table>
Recommendations of the Committee

2. To further enable the DGH to carry out best-in class technical feasibility assessments, the committee recommends the following
   - The DGH should have the freedom to employ external agencies for carrying out technical feasibility assessment as required
   - Bring the calculation of Profit Petroleum and profit sharing, as stipulated in the PSC, under the purview of the Income Tax Department, under the jurisdiction of MoF

3. Streamline the approval process and bring in transparency
   - Standardize the clearance requirements as much as possible by creating a single window clearance system for O&G projects.
   - Adopt a concurrent approach for statutory approvals to minimize the total time taken.
   - Establish IT based workflow system and move to E-governance.

   Establish an inter-ministerial panel to whom the MOPNG may entrust the dispute resolution mechanism for a flexible dispensation depending on the circumstances to ensure timely resolution of issues concerning PSCs

3.4.1 In line with the current PSC, the government is required to ensure proper budget monitoring, benchmarking and allocation of costs, including those relating to procurement, exploration and development. The process for such a review is lengthy, onerous and results in extensive government involvement in day-to-day operations, which is cumbersome for both the government and operators. In certain instances this could also lead to delays in the implementation of the work plan, which would in turn have a negative impact on the economics of the project and thus on investor interest.

3.4.2 By virtue of Section 42 and 80 IB(9), the cost data submitted to the Income Tax Department for computation of income tax will be equally applicable for computation of Profit Petroleum under the provisions of PSC. Presently, assessment of income tax and computation of Profit Petroleum are done by two different agencies, such as the Income Tax Department and DGH/ MOPNG respectively. In order to avoid duplication of efforts and ensure consistency and integrity of cost data used for the purpose of assessment of income tax and computation of Profit Petroleum, the Profit Petroleum monitoring can be shifted under the jurisdiction of Income Tax Department, under the MOF. (Refer Annexure D)
3.4.3 The government's involvement in day-to-day operations is to ensure that the firms do not spend additional capital or resources than required to produce the hydrocarbons; this practice is also termed as 'gold plating'. The assumption is that contractors in a PSC framework would not exercise cost discipline as they are assured cost recovery. However, every dollar of unwarranted expenditure is recovered from the project revenues, and adversely impact contractor returns in the ratio of its share in profit. As the investor puts up the risk capital upfront, he is not incentivized to gold-plate and it is in his interest to minimize capital spend across all stages of field life. In principal, the profit petroleum computation under the PSC is similar to the computation of taxable profit under the Income Tax Act. Although the 'Government take' i.e. the corporate tax is dependent on the profitability of the company yet the government does not get involved in the day to day operation of the corporate. On similar lines, government should restrict its involvement in activities of E&P operators. Given full alignment between the Government's and contractors interest under the PSC system, technical assessment need to be given more importance rather than judging them on techno-economic merits. As provided in the PSCs, the Contractors are supposed to adopt the Good International Petroleum Industry Practices (GIPIP) while developing such discoveries. The committee believes that, because it is in the best interest of operators to use their funds efficiently, the government does not need to be continuously involved in evaluating the commercial feasibility of projects. To ensure that the DGH is well equipped to carry out-best-in class technical feasibility assessments, the committee recommends the following:

- The DGH should have the freedom to employ external agencies for carrying out technical feasibility assessment as required
- Bring the calculation of Profit Petroleum and profit sharing, as stipulated in the PSC, under the purview of the Income Tax Department, under the jurisdiction of MoF

3.4.4 The government needs to streamline the execution of PSCs to minimize delays incurred by operators in carrying out E&P activities. The committee recommends the following steps to ensure smooth execution of PSC

- Standardize the clearance requirements as much as possible with creating a single window clearance system for O&G projects.
- Adopt a concurrent approach for statutory approvals to minimize the total time taken.
- Establish IT based workflow system and move to E-governance. All submissions to the Government should be reduced to electronic formats, all permissions should be electronically transmitted, decision making process should be computerized, rules policies regulations should be available on-line, and timelines should be electronically identified.

3.4.5 Establish an inter-ministerial panel to whom the MOPNG may entrust the dispute
resolution mechanism for a flexible dispensation depending on the circumstances to ensure timely resolution of issues concerning PSCs

3.5 Financial audits related to recovery cost

<table>
<thead>
<tr>
<th>Recommendations of the Committee</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Any financial audits relating to PSC should be carried out based on accounting records and financial statements prepared under the provisions of the PSC in accordance with the Accounting Standards and Audit Standards of the Institute of Chartered Accountants of India (ICAI).</td>
</tr>
<tr>
<td>2. The government may conduct the audit through firms of Chartered Accountants or through the Comptroller and Auditor General (CAG), or through international auditors with assistance from management consultants and other experts with relevant experience in auditing oil and gas operations. Such an audit – whether conducted by the CAG or others – should not include performance or efficiency auditing that lies beyond the scope stipulated by the ICAI.</td>
</tr>
<tr>
<td>3. In the event of any report of fraud or related irregularities, the government may determine the need for a forensic or investigative audit in addition to the annual audit.</td>
</tr>
<tr>
<td>4. The government shall make all efforts to complete the audit procedure in accordance with the timelines set out in the Accounting Procedure.</td>
</tr>
</tbody>
</table>

3.5.1 Examination of PSCs across different countries shows that PSCs determine the exclusive mandate within which the audit is conducted. They also define the approach with which audits should be conducted. Production sharing agreements (PSAs) between government and private operators are treated as abiding constitutional documents that set boundary conditions for the risk-reward sharing mechanism for operators. Across the world, there is a general consensus that the auditor should not substitute its understanding for the business judgments and decisions of operators. Technical matters – such as the declaration of commerciality, the appraisal program, the extension of time, the extension of area, unitization and the production rate – are determined by regulators and operators that have a proven track record in this field, and should remain outside of the purview of audits. (Refer Annexure E)

3.5.2 In India, Section 42 of Income Tax Act read with Article 17.2 of the PSC specifies the scope of cost recovery under the PSC. A perusal of the same shows that the assessment of cost recovery is similar to the scope of expenditure allowance granted under the Income Tax Act for the purpose of income tax computation. The Profit Petroleum computation under the PSC is similar to the computation of taxable profit under the Income Tax Act. Therefore, the scope of the statutory audit and tax audit conducted on the books of the accounts of the company participating in the PSC for the purpose of income tax can be a sound basis for the scope of the audit
conducted to assess cost recovery under the provisions of the PSC. The scope of audit under the PSC does not require a performance audit to be conducted or the expenditure efficiency to be judged and audited for determining cost recovery. The audit should focus on the following:

- Whether petroleum that is produced and saved has been correctly valued
- Whether expenditure is duly supported with evidence of cash flow and has been correctly classified into Exploration Cost, Development Cost and Production Costs in accordance with Accounting Standards
- Whether transactions are arm’s length and affiliated transactions, if any, have been identified and reported.

3.5.3 In light of the above and benchmarking against the global PSA audits, the committee has arrived at the following recommendations:

- The auditor should audit the accounting records and financial statements prepared under the provisions of the PSC in accordance with the Accounting Standards and Audit Standards of the ICAI.
- The government may carry out the audit through chartered accountancy firms, through the CAG or using international auditors with assistance from management consultant and other experts with relevant experience in auditing oil and gas operations. Such audits, whether conducted by the CAG or others, should not include performance or efficiency auditing that lies beyond the scope stipulated by ICAI.
- In the event of any report of fraud or related irregularities, the government may determine the need for a forensic audit or investigative audit in addition to the annual audit.
- The government shall make all efforts to complete the audit procedure in accordance with the timelines set out in the Accounting Procedure.

3.6 Small and marginal fields policy

<table>
<thead>
<tr>
<th>Recommendations of the Committee</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. NOCs should have the flexibility to bring in an experienced partner for IOR/EOR schemes to ensure implementation of best practices</td>
</tr>
<tr>
<td>2. NOCs should be allowed to put small and marginal fields out to global tender and form contracts with interested parties for the same purpose</td>
</tr>
<tr>
<td>3. Small and marginal field projects should receive international prices of oil and gas, and not be subjected to contribution towards downstream under recoveries</td>
</tr>
</tbody>
</table>

3.6.1 The term “marginal field” refers to a field that – due to various factors (geological, geographic, technical or economic) – may not produce enough net income to make it worth
developing at a given time. Though production from these fields is individually low, cumulatively they can make a significant contribution to nation’s hydrocarbon production. It is estimated that India has more than 200 marginal fields, with less than half under development. Marginal fields have the potential to make a significant contribution to reducing India’s dependence on imported oil.

3.6.2 Returns on investment for most marginal fields are limited and, under the current fiscal regime, do not justify operator efforts. To address operators’ concerns, governments across the world have implemented policies that stimulate production from these fields by offering assured commercial returns. In line with global best practice, India should create fiscal incentives so that marginal fields can be swiftly exploited. To improve the commercial viability of the projects and generate investor interest, marginal field projects of NOCs should receive international prices of oil and gas, and not be subjected to contribution towards downstream under recoveries.

3.6.3 Efficient development of marginal fields will require introducing best-in-class technologies. The government should create a policy framework that allows NOCs to bring in experienced partners. As part of the policy framework, NOCs should be allowed to put marginal fields (Including for nominated blocks) out to global tender and to form contracts with interested parties for the same purpose.

3.7 Unconventional oil and gas policy

<table>
<thead>
<tr>
<th>Recommendations of the Committee</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Current policy permits NOCs to explore for shale oil and gas resources from onland blocks that were allotted to them on nominated basis. A similar policy should be put in place for other private companies operating under PSC regime.</td>
</tr>
<tr>
<td>2. Coal India Limited (CIL) should seek to engage with private players and NOCs to develop capabilities in gas extraction, to exploit gas from CBM.</td>
</tr>
</tbody>
</table>

3.7.1 Shale gas has been a game changer in the US energy landscape. In less than a decade, US supply has shifted from that of deficit to surplus. Many agencies have predicted huge shale gas potential in Indian basins. Shale gas may account for more than 75%⁴ of India's untapped yet-to-find potential, according to certain industry estimates. Development of shale gas could represent a significant step towards India's goal of achieving energy security.

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⁴ Source: Rystad database
3.7.2 The government has recently taken a crucial step towards developing India's shale gas and oil reserves by permitting NOCs to explore for shale gas and oil resources from onland blocks that were allotted to them on nominated basis. The committee strongly recommends that similar policy be put in place immediately, allowing other private companies to explore shale oil and gas potential from nominated blocks.

3.7.3 Further recommendations on shale gas and oil policy will be covered in Part -2 of the report.

3.7.4 Among other unconventional sources, CBM opportunities in India need to be put on priority to meet the country's energy needs. However, successful and sustained extraction from CBM basins would require a clear understanding of the technological and environmental aspects of such gas extraction. To achieve this, Coal India Limited (CIL) would be required to get a clear understanding of the process and challenges related to successful extraction of gas from CBM. It is thus important that CIL leverages the knowledge and expertise of private players in upstream O&G, as well as NOCs to develop such capabilities.

3.8 Under-recovery issues related to NOCs

<table>
<thead>
<tr>
<th>Recommendations of the Committee</th>
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</thead>
<tbody>
<tr>
<td>1. The Reduce the under-recovery burden of upstream oil companies. In principle, the upstream companies should not be required to subsidize under recovery of downstream companies. To make rapid progress towards easing of the under recovery burden of upstream companies, three possible solutions are suggested:</td>
</tr>
<tr>
<td>• Phase out regulation of diesel and kerosene prices in line with the recommendations of the Parikh committee, which could bring down the overall subsidy burden, thereby reducing the under-recovery of upstream companies</td>
</tr>
<tr>
<td>• If the government decides against deregulation, it should finance a higher proportion of the subsidies from its own revenue receipts</td>
</tr>
<tr>
<td>• The Parikh committee recommendations should be adopted at the earliest for calculation of under-recoveries</td>
</tr>
</tbody>
</table>

3.8.1 In India, petroleum products are sold to consumers at a subsidized rate. The government has indirectly fixed the end-consumer price of petroleum products sold at retail pumps under the Administered Pricing Mechanism (APM). Although the government is taking steps to deregulate pricing, diesel and kerosene prices are still significantly lower than market-determined levels. The burden of these subsidies is shared between the government and NOCs.
3.8.2 NOCs play a crucial role in achieving India's goal of enhancing oil and gas production from domestic resources. The under recoveries significantly impact NOCs' profits, hampering their exploration and growth plans. The government needs to address these concerns to ensure NOCs play their envisaged role in achieving energy security for India.

3.8.3 To ensure that upstream companies continue investing in the exploration, production and acquisition of assets, the committee recommends easing the subsidy burden using the following solutions:

- Phase out regulation of diesel and kerosene prices in line with the recommendations of Parekh committee, which could bring down the overall subsidy burden, thereby reducing the under-recovery of upstream companies
- If the government decides against deregulation, it should finance a higher proportion of the subsidies from its own revenue receipts
- Parikh committee recommendations should be adopted at the earliest for calculation of under-recoveries

3.9 Benefits akin to Infrastructure structure for the E&P sector

<table>
<thead>
<tr>
<th>Recommendations of the Committee</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. The E&amp;P sector should be granted benefits similar to those granted to sectors that have been given infrastructure status</td>
</tr>
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</table>

3.9.1 The oil and gas industry constitutes a vital infrastructure, underpinning the economy by providing the energy needed for consumers and businesses to thrive. The oil and gas industry is also critically important to the country’s financial health, since huge imports of energy are adding to India’s large current account deficit. Because E&P operators need to invest heavily in the exploration and asset development phases before any revenues can be earned from an oil field, they are highly risk averse. To encourage investors to embark on E&P activities in India, the government needs to provide companies with easy access to funds.

3.9.2 The following industries have so far been granted infrastructure sector status in India: Roads and bridges; ports; airports; electricity generation, transmission and distribution; oil pipelines, liquefied natural gas storage facilities; telecommunication towers; educational institutions; hospitals and three-star or higher category classified hotels located outside cities with a population of more than one million. The benefits extended to these industries via infrastructure status have had a significant impact on investments in these sectors.
3.9.3 Infrastructure status offers many benefits, such as access to external commercial borrowing through automated routes. Section 80-IA of the Income Tax Act provides special benefits for the companies involved in infrastructure development. Upstream oil companies already enjoy many of these benefits (such as the tax holiday for the first few years of production). Companies that are operating in the infrastructure sector find it easier to access financing and viability gap funding from banks. The government should extend these benefits to E&P companies to ensure that the sector has easy access to funds.

3.9.4 There are concerns that if E&P companies were granted infrastructure status, this would adversely affect existing sectors in the infrastructure domain by taking away the lion's share of their benefits. To address this, the government could consider extending benefits to the E&P sector which are in line with the other sectors, without officially granting it infrastructure status.

3.10 Strengthen DGH to ensure effective sector regulation

<table>
<thead>
<tr>
<th>Recommendations of the Committee</th>
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</thead>
<tbody>
<tr>
<td>1. OIDB cess should be used to fund strengthening of DGH, as needed</td>
</tr>
<tr>
<td>2. The DGH needs to create an HR pool by hiring the best talents</td>
</tr>
<tr>
<td>3. The DGH should have the freedom to recruit international experts at global compensations as required</td>
</tr>
</tbody>
</table>

3.10.1 For optimal functioning, the regulatory functions of the government need to be streamlined to ensure operational efficiency and to ensure timely approvals for work programs and budget and field development plans. As India embarks on OALP there will be more contracts to be administered by the DGH. A large proportion of India's undiscovered resources lie in difficult terrains, such as frontier onland areas and ultra-deep water areas, where the complexity of the fields is higher. Thus, the need for the DGH to build the required capabilities to ensure effective contract administration cannot be overemphasized.

3.10.2 Lack of capacity and capability are both a roadblock in the smooth administration of the contracts. To overcome this challenge government should seek to create an HR pool of talent within the DGH as followed in Norway, Indonesia and others by hiring the best in class personnel. DGH should build capability building training plan in line with individual and group responsibilities. OIDB cess can be used for the above purposes and to further strengthen DGH. As discussed in section 2.4, to ensure that the DGH is well equipped to carry out best-in class technical feasibility assessments, the committee recommends the following:
To augment its internal expertise, the DGH should seek for learning from the international community. To this end, the government should help attract international talent by permitting the DGH to offer compensation packages that are in line with global standards.

The DGH should have the freedom to deploy services of leading global experts as required.
Chapter 4

The future work program
4 The future work program

This section highlights the major issues that will be covered in Part II of the report. Topics in Early action measures and the way forward together encompass all the terms of reference of the committee.

4.1 Policies for unconventional resources covering Shale gas and oil, CBM, Gas Hydrates

The Unconventional Hydrocarbons Industry is in its nascent stages in India and needs to be nurtured to meet the increasing energy needs of the country. India has substantial reserves of unconventional hydrocarbons and if these are developed properly, India would be able to meet a significant part of the country’s rising energy requirements. The major unconventional energy sources which can be prioritized for development to meet the energy shortfall are coal bed methane (CBM), shale gas and oil, methane hydrates, etc. In order to enhance domestic oil and gas production from unconventional energy sources, a comprehensive energy policy for the exploration and development of unconventional energy assets should be formulated.

The committee is deliberating on the essential policy initiatives and Part II of the report will comprise details on all aspects such as land acquisition, water usage, marketing rights, pricing, etc related to development of unconventional.

4.2 E&P contract structure

E&P contract between the state and interested parties should reflect a balanced risk reward paradigm with due cognizance to India’s prospectively and materiality. Striking the balance between the two is crucial to attract investors to conduct E&P activities in the country. Australia, Brazil, Malaysia, Indonesia, amongst others have been successful in transforming their hydrocarbons sector in a period of couple of decades. It would much benefit our country to study the contract structure of these hydrocarbons regimes.

As discussed earlier, the Committee has compared the economic soundness of PSC and revenue share. Going forward, committee would also evaluate PRRT (Petroleum rent rate tax) as prevalent in Australia and AAT (auxiliary additional tax) which is structured in line with the windfall tax model as seen in countries like Venezuela, Columbia before recommending the most suitable model(s) for the Indian context.
4.3 Ways to utilize OIDB cess

Many issues regarding collection of OIDB (Oil Industry Development Board) cess and its utilization have been raised by the Industry. The committee is deliberating upon suggestions of different stakeholders and will provide its final recommendation in Part II of the report.

4.4 Policies to develop and promotion indigenous service industry in E&P sector

The E&P service providers have played a key role in the success of E&P operators worldwide. The typical spends of E&P operators on outsourced work to service providers is more than 60% of their total E&P costs which highlights the significance of service providers. India too relies heavily on the oilfield service providers. This reliance is expected to grow in the future. Hence there is a need for the development and promotion of indigenous service industry in the E&P sector. The committee’s recommendations will include

- Steps to create a talent hub
- Measures to improve the operating environment including possibility of creating a dedicated oil field service zone
- Fiscal incentives
- Policies to promote domestic companies in international markets

4.5 Review of institutional mechanism to acquire oil and gas from abroad

Acquiring gas and oil acreages has become intensely competitive with large energy consuming nations becoming active in implementing strategies for energy security. The committee is deliberating on policies and initiatives that will help O&G companies develop financial, strategic and operational capabilities to acquire acreages abroad for exploration and production and import gas from other countries

Develop financial capabilities

The committee is evaluating various possible initiatives that can be undertaken to ensure domestic companies have easy access to funds and necessary support from government to acquire oil and gas from abroad. They mainly include possibility of creating sovereign fund, easy access to low cost capital and other fiscal incentives. There are similar initiatives implemented in other countries like China which are being studied by the committee before arriving at the final recommendation

Develop strategic and operational capabilities

To develop the required strategic and operational capabilities for Indian companies to effectively identify, acquire and operate assets abroad, the committee is evaluating various ways to
enhance government – to- government interaction, streamlines government decision making and empower O&G PSU’s to execute large deals and attract the best talent.

4.6 Steps to promote R&D and increase technological base in E&P sector

As the era for 'easy oil' fast approaches its end it is critical for nations to continually develop capabilities and technical expertise through focused R&D. Building knowledge infrastructure in E&P activities would entail substantial capital investment for both the NOCs and private oil companies.

Keeping in view the key enablers required to promote R&D in the sector, the committee recommendations would mainly cover the ways to mobilize funds for R&D, promote collaboration with major countries/companies for knowledge share, suggestions for setting up more institutions and other fiscal incentives.

Developing the next wave of unconventional like the gas hydrates would constitute the extreme technological end of the unconventional spectrum, as traditional below ground techniques fall short of the commercialization of the resource. Commercialization of these difficult to develop hydrocarbon will be contingent on significant technological progress at the very least. Given its importance, the committee is deliberating on incentives to encourage companies, R&D institutes to explore new technology frontiers, which will be covered in Part II of the report.

4.7 Steps to develop gas transportation infrastructure

Most of India’s natural gas, shale gas and CBM resources are untapped. Developing these resources is critical to bridge the energy demand – supply gap in India. To incentivize investors to develop these resources it is of paramount importance that the gas network is spread to all parts of the country. The part II of the report will include committee recommendations (w.r.t the gas sector) on the following

- Initiatives to improve funding
- Role of NG in India’s Energy basket
- Sourcing of Gas and Price
- Fresh look at markets

4.8 Roadmap to switching over to market determined gas pricing

The committee has received various inputs from the Industry on the roadmap for shifting to market determined gas pricing. The committee will present its recommendation on the same in Part – II of the report.
Roadmap for Reduction in Import Dependency in Hydrocarbon Sector by 2030– Part I

- Policy on unbundling and open access
- Taxes and tariff reforms
- Steps to improve governance

4.9 Roadmap to set up new institutional framework for the hydrocarbon sector

The role of a government in the growth of the E&P sector has to be that of a catalyst in providing the market conditions and investor assurance for growth. For sustainable flow of investments, both IOCs and NOCs need the assurance of support for market outcomes and clarity in the basis for decisions. The committee is reflecting on new institutional framework which will include details on Independent empowered regulator, restructuring of DGH amongst others.

(Ashok Ganguly) (Deepak Parekh) (R S Sharma)

(S.V. Rao) (Vikram Mehta) (Arindam Bhattacharya)

(Ajit Kapadia) (Anil K Jain) (R N Choubey)

(Vijay Kelkar)
Chairman
5 Annexure

5.1 Annexure A: Details of meetings with stakeholders

Representatives of the following E&P companies, industry associations and scholars were also offered an opportunity – in their individual capacity – to present their views to the committee.

(a) On 3 May 2013

1. Association of Oil & Gas Operators (AOGO)
2. The Boston Consulting Group (BCG)
3. ONGC Videsh Ltd. (OVL)
4. Shri Atul Chandra, Ex-MD, OVL

(b) On 31 May 2013

1. Shri Ajit Kapadia
2. Tata-Sasol
3. Reliance Industries Ltd (RIL)
4. Shell

(c) On 20 July 2013

1. British Petroleum (BP)
2. Dr. Rabi Bastia, President E&P, Oilmax Energy
3. The Boston Consulting Group (BCG)
4. Shri Anil K. Jain, Advisor (Energy), Planning Commission
5. Shri Ajit Kapadia, Vice Chairman, Centre for Fuel Studies and Research
6. Shri R. N. Choubey, Directorate General of Hydrocarbons (DGH)
7. Oil and Natural Gas Corporation Limited (ONGC)

(d) On 14 August 2013

1. The Boston Consulting Group (BCG)
2. Association of Oil & Gas Operators (AOGO)
3. The Energy and Research Institute (TERI)
4. South Asia Gas Enterprise (SAGE)
5. Observer Research Foundation (ORF)
6. Dr. Avinash Chandra, Ex-Director General, DGH
(e) On 2 September 2013
1. Cairn India Limited (CIL)
2. ASSOCHAM
3. Confederation of Indian Industries (CII)
4. Praj Industries Limited.

(f) On 5 October 2013
1. Shri Vivek Rae, Secretary, P&N
2. The Boston Consulting Group (BCG)
3. Federation of Indian Chambers of Commerce and Industry (FICCI)
4. Shri R. S. Pandey, former Petroleum Secretary
5. Shri G. C. Chaturvedi, former Petroleum Secretary

5.2 Annexure B: Methodology to compare Revenue Share vs. PSC models

**Approach A**

A ‘real world’ simulation of comparing the new revenue share model and PSC models was undertaken to understand the impacts of the two mechanisms on 3 key parameters - production, government revenues, and risk capital.

Probabilistic economic modeling (Monte Carlo simulation) was conducted on a broad based dataset of 20,000 fields covering the range of operating environments from the easiest (onshore oil and gas) to the most difficult (deep water oil and gas). A representative field distribution curve was attributed for each of the 4 operating environments – onshore oil, onshore gas, deep water oil and deep water gas. Representative cost, well deliverability assumptions and production profile assumptions were used to arrive at an estimate of project, government and contractor value. To calculate project revenues, gas prices assumed were as per the Rangarajan Committee formula and oil prices close to current levels at $100/bbl. Inflation in prices and costs was not introduced in the model, to remove the possibility of any biases related to factors outside the control of the project.
For both the PSC and the Revenue Share models, it is assumed that the contractors will display rational and similar bidding behavior, to meet similar rates of return, irrespective of the contract regime. This ignores that the Revenue Share model increases the risk to the investors and investors will likely require higher returns under this model.

Further under both regimes and all operating environments, it is assumed that higher volumes and project materiality leads to economies of scale.
Figure 16: Detailed assumptions

- **Fiscal Assumptions**: to achieve representative Contractor returns
  - Assumed National Competitive Bids for both Revenue Share and PSC
  - For each region Fiscal bid assumed which provides similar rate of return for a representative reserve level for each region
  - Assumed all in a slope of Government payments (share of profit petroleum / production linked payments)

- **Price and other inputs for evaluation**
  - Gas price as per Petroleum Committee recommendations
  - Oil Price of $100/bbl
  - No inflation in price and costs

- **Probabilistic Economic Modeling**
  - Analysis based on output from Monte Carlo simulation. Contractor NPV and Government NPV simulations for all the 20,000 data points for each region
  - Minimum economic volume estimated below which contractor believes reserves are not economic enough to be developed and exits the block.
  - Expected Government NPV estimated which is equal to average Government NPV for reserves where above economic volume multiplied by chance of economic volumes

**Detailed Operating Environment, Fiscal and Price, and Development Assumptions**

1. Field Size distributions for the four regions representing the discovery sizes expected in the four regions. These distributions have been used for running Monte Carlo simulations

<table>
<thead>
<tr>
<th>Field Type</th>
<th>P90</th>
<th>P50</th>
<th>P10</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Onshore Oil</td>
<td>10 mmbbls</td>
<td>50 mmbbls</td>
<td>120 mmbbls</td>
<td>Associated Gas reinjected</td>
</tr>
<tr>
<td>Deepwater Oil</td>
<td>50 mmbbls</td>
<td>150 mmbbls</td>
<td>300 mmbbls</td>
<td>Associated Gas reinjected</td>
</tr>
<tr>
<td>Onshore Gas</td>
<td>200 bcf</td>
<td>1000 bcf</td>
<td>2000 bcf</td>
<td>CGP: 30; Condensate sold at 20% discount to oil</td>
</tr>
<tr>
<td>Deepwater Gas</td>
<td>500 bcf</td>
<td>2000 bcf</td>
<td>4000 bcf</td>
<td>CGP: 30; Condensate sold at 20% discount to oil</td>
</tr>
</tbody>
</table>

2. Royalty rates assumed as per the current legislation
3. Revenue Share Assumptions
### Roadmap for Reduction in Import Dependency in Hydrocarbon Sector by 2030– Part I

#### 4. PSC Assumptions

<table>
<thead>
<tr>
<th>Deep water oil</th>
<th>Deepwater gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production rate (mbod)</td>
<td>90</td>
</tr>
<tr>
<td>&gt; 0 &lt;= 50</td>
<td>50</td>
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<tr>
<td>50</td>
<td>100</td>
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<table>
<thead>
<tr>
<th>Onshore oil</th>
<th>Onshore Gas</th>
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<tbody>
<tr>
<td>Production rate (mbod)</td>
<td>90</td>
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<tr>
<td>&gt; 0 &lt;= 10</td>
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<td>10</td>
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</tbody>
</table>

#### 5. Price Assumptions
- Oil price of $100/bbl
- Gas price as per Rangarajan Committee
6. Development Assumptions

<table>
<thead>
<tr>
<th></th>
<th>Onshore Oil</th>
<th>Onshore Gas</th>
<th>Deepwater Oil</th>
<th>Deepwater Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Profile</td>
<td>12% plateau</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Well deliverability</td>
<td>250b/d</td>
<td>3 mmscfd</td>
<td>6000 b/d</td>
<td>40 mmscf/d</td>
</tr>
<tr>
<td>Number of wells</td>
<td>As per average well deliverability</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water and gas</td>
<td>65% of producer</td>
<td>Not applicable</td>
<td>50% of producer wells</td>
<td>Not applicable</td>
</tr>
<tr>
<td>injection wells</td>
<td>wells</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Concept</td>
<td>Separation facilities/ land, power plant, pipelines, water injection facilities</td>
<td>Processing and separation facilities. Onshore terminal Pipelines</td>
<td>FPSO with processing and separation. Pipelines with subsea development</td>
<td>Subsea development with pipelines to an Offshore Controls &amp; Riser Platform for processing and separation and onshore terminal</td>
</tr>
</tbody>
</table>
### Roadmap for Reduction in Import Dependency in Hydrocarbon Sector by 2030– Part I

<table>
<thead>
<tr>
<th></th>
<th>Onshore Oil</th>
<th>Onshore Gas</th>
<th>Deepwater Oil</th>
<th>Deepwater Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Facilities Capex</strong>¹</td>
<td>$70m for 10 mmbbl</td>
<td>$800m for 1 tcf case</td>
<td>$2bn for FPSO and common subsea cost</td>
<td>$5 billion for 2 tcf case</td>
</tr>
<tr>
<td><strong>Exploration &amp; Appraisal Capex</strong></td>
<td>Exploration well and seismic Appraisal wells estimated on basis of reserves</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Operating Cost</strong>¹</td>
<td>$15 m for 10 mmbbl case</td>
<td>$50 m for 1 tcf case</td>
<td>$150m for 30,000b/d (100 mmbbls case)</td>
<td>$200 m for 650 mmscfd facility (2 tcf case)</td>
</tr>
</tbody>
</table>

¹Appropriate economies of scale assumed to scale up and down from base case

**Approach B**

India's sedimentary basins are divided into 1132 fields spread across different stages of development. Year on year estimates of production profiles, Capex, Opex up to year 2100 are used to create the cash flow statement for each of the 1132 fields. The cash flow for each field are created for both the contractual regimes to compare the impact on Net present value (NPV) of the investor take and net present value of the government take.

We have incorporated multiple price scenarios with varying price CAGR for the relevant time period to evaluate the impact of prices on the output. In line with EIA estimates, we have used a 3% price CAGR as base price. For baselining the contractual regime parameters across Revenue share and PSC, a goal seek is done to identify the optimal parameters for consistent government take across the 1132 fields on a cumulative basis.
Figure 18: Overall simulation approach

- Fields
- Production
- Costs
- Economics
- ~1100 fields
- Asset specific profiles
- Detailed Capex / Opex
- Cash flows per field

- Reserve estimate based on field maturity level
- Public data sourcing based on web crawler with QC system
- Profile modelling based on historic data or proxies
- Field development likelihood based on probabilities
- Cost level / split estimates based on few concepts
- Cash flow per field calculated from start of exploration up to 2100 years under both the contractual regimes

- 7 nominal oil price scenarios shape the expected view
  - Base price scenario is taken at 3% Cagr, in line with EIA latest estimate

Detailed Operating Environment, Fiscal and Price, and Development Assumptions

1. Detailed assumptions on fields from currently producing to open acreage

Figure 19: Simulation logic and detailed assumptions

- Fields
- Logic applied and detailed assumptions
- ~1100 fields
- Remaining reserves
- Expected ultimate reserves
- Discovery size
- Probabilistic reserves
- Creaming curve reserves
- Estimated from historical reserves and production data
- Based on development conceptual plans
- Calculated using drilling costs as proxy
- Track record of each Co. to check credibility
- Calibrated by well test data (if any)
- Combine probabilities
  - P(10%)
  - P(50%)
  - P(90%)
  - USGS data
- Remaining reserves at both level (from creasing curve)
- Licensing rounds simulated for allocation
- Heeby / similar acreages as proxies

Mostly official (company) published data

Footnote: 1. The availability changes, 2. Used for weekly check and bank of reserves on trend of production curve
2. Detailed assumption on Production

**Figure 20: Detailed assumption on production**

- Detailed cost assumptions

**Figure 21: Detailed cost assumptions**

3. Royalty rates assumed as per the current legislation

4. Revenue share percentage: 26%
5. PSC assumptions

<table>
<thead>
<tr>
<th>Cost recovery</th>
<th>100%</th>
<th>100%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Investment multiple tranches</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Government take</td>
<td>1.5</td>
<td>20%</td>
</tr>
<tr>
<td>Investor take</td>
<td>80%</td>
<td></td>
</tr>
<tr>
<td>&gt;=</td>
<td>3.5</td>
<td>50%</td>
</tr>
<tr>
<td></td>
<td>50%</td>
<td></td>
</tr>
</tbody>
</table>

6. Cost of capital
   - Cost of capital for calculation of net present value: 12%

7. Income tax holiday assumed to be for 7 years from start of production

8. Corporate tax rates assumed as per the current legislation
5.3 Annexure C: Projection of supply-demand balance 2012-2030

1. Base case scenario

Growth in supply of domestic hydrocarbon resources is expected to be below the rate of demand growth, widening the supply-demand gap in 2030 to 50% of total energy demand; the resulting import outlay for this energy reaching 293 Bn USD\(^5\).

If no significant measures are implemented and urgently, India is expected to import between now and 2030 a cumulative amount of energy equivalent to 3.6 Trillion USD, more than twice the current Gross Domestic Product as shown in figure one below.

---

\(^5\) Value for imported oil and gas is taken as 100 USD per Barrel of oil equivalent
2. Scenario I – Stimulation of production base

If India is able to stimulate oil production by facilitating exploration and development of new fields, technology infusion in existing fields, supply-demand gap can be bridged significantly. A quick action can significantly reduce energy import bill and result in savings of 1.2 Trillion USD$ from 2013–2030 as shown in Figure 26.

Figure 23: Scenario I of supply and demand balance 2012-2030

6 Model assumptions used 1. Ramp up of 3 years, Plateau of 10 years (Annual 7% of total reserve), Tail of 10 years, Resource recovery 30% EOR recovery of additional 10% for fields with production >10 kbb/day 2. Ramp up of 6 years, Plateau of 40 years 3. Production CAGR 2013-2040 of 4% 4. Production CAGR 2013-2040 of 4.2%
3. Scenario II – Aggressive push on coal and renewable
Further expediting of O&G resources, and an aggressive push on coal and other renewable resources through the right policy measures could result in near self sufficiency and reduce cumulative imports to USD 1 trillion as shown in figure 3⁷

![Figure 24: Scenario II of supply and demand balance 2012-2030](image_url)

---

⁷ Model assumptions used 1. Ramp up of 3 years, Plateau of 10 years (Annual 7% of total reserve), Tail of 10 years, Resource recovery 30% EOR recovery of additional 10% for fields with production >10 kbb/day 2. Ramp up of 6 years, Plateau of 40 years 3. Production CAGR 2013-2040 of 5.2% 4. Production CAGR 2013-2040 of 6.8%
5.4 Annexure D: Fiscal monitoring under PSC

I. Under the existing Production Sharing Contracts (PSC), the Government Take essentially is constituted of the following:

   a. Exploration License fee / Mining lease fee (PEL / ML fee)
   b. Royalty
   c. Profit Petroleum
   d. Cess

II. Presently the PEL / ML fee and Royalty are monitored by respective Governments, i.e., State Government in the case of on-land blocks and Central Government (MOP&NG) in the case of offshore blocks. The Profit Petroleum is monitored by DGH / MOP&NG.

III. Two provisions of the Income Tax Act, 1961 grant special concession to upstream oil and gas operations:

   a. Section 42 of the Income Tax Act, 1961, dealing with the ‘Special provision for deductions in the case of business for prospecting, etc., for mineral oil’, provides that the allowances admitted under the PSC would be considered as expenditure allowance for income tax computation. This Section stipulates that: “For the purpose of computing the profits or gains of any business consisting of the prospecting for or extraction or production of mineral oils in relation to which the Central Government has entered into an agreement with any person for the association or participation of the Central Government or any person authorized by it in such business (which agreement has been laid on the Table of each House of Parliament), there shall be made in lieu of, or in addition to, the allowances admissible under this Act, such allowances as are specified in the agreement”.

   b. Section 80 IB(9) provides for exemption of tax on profits for a period of seven years. Rule 18 BBB requires that the assessee shall furnish Profit and Loss and Balance Sheet for claiming tax exemption along with audit report in format 10CCB. The tax exemption is available contract-wise and therefore a PSC is treated as a separate entity.

IV. By virtue of Section 42 and 80 IB(9), the cost data submitted to the Income Tax Department that becomes the basis for computation of income tax will be equally applicable for computation of Profit Petroleum under the provisions of PSC. However the present twin-mechanism of validating the taxable income and the Profit Petroleum by two different agencies, such as the Income Tax Department and DGH/ MOP&NG respectively, results in duplication of effort and likelihood of discrepancy between the cost data submitted to the two agencies.
V. In order to avoid duplication of efforts and also to ensure consistency and integrity of cost data used for the purpose of assessment of income tax and computation of Profit Petroleum, the Profit Petroleum monitoring can be conveniently shifted to the jurisdiction of Income Tax Department, under the MoF.

VI. The proposal, in addition to the advantages stated above, will enable strengthening of the monitoring of Profit Petroleum, which is expected to increase substantially from the present range of Rs 10,000 crores per annum. As the proceeds of Profit Petroleum go to the consolidated fund, it may be more appropriate that the Profit Petroleum is monitored by the Income Tax Department under the jurisdiction of MoF.

5.5 Annexure E: Auditing of PSAs – India vs. Global practices

- Scope of Audit: PSA determines the exclusive mandate within and according to which the audit is conducted. World over nothing beyond the PSA can be read in to define or expand the list of matters to be examined and the approach for the same. PSAs are honored as abiding constitutional documents setting boundary conditions for the ventures’ risk reward sharing mechanism;

- Respect for the decisions taken at Fora like Operating Committee: (Auditor cannot substitute his understanding for business judgments and decisions of persons competent to take the same under relevant agreements)

- Technical matters such as declaration of commerciality, appraisal program, extension of time, extension of area, unitization, production rate etc. are highly technical and evolving subjects. (World over these issues are left to be the business judgment of investor to be addressed through expert determination in situations of differing perceptions)

- The PSA audit is globally restricted to financial audit. Even countries with enormous oil, have faced insurmountable problems on project progress through Govt. auditors. An example, Kashagan Contract in Kazakhstan nearly entered a deadlock when the cost recoveries audit through state auditors threatened disallowance to the extent of Billions of Dollars (for some years even 90% of the cost spent was disallowed). When impasse [persisted the State appointed professional accountants to resolve and the Project is back on track (though even now some distrust of the past seems to be still on mind of investors, which is affecting project progress).

- Concepts like proprietary and performance mean different things to investors in private sector and public sector in terms of risk perception and willingness to take risk. With investors coming from dissimilar backgrounds, they are likely to get confused by these concepts as such to be applied by Govt. auditors, which are geared towards ensuring
protection of public money. So scope of PSA audit cannot include aspects relating to proprietary or performance audit.

- Repeat audit (initial audit by some agency and subsequent audit by CAG) like in case of Panna-Mukta has been totally unheard of.

- India developed its PSC mechanism based on regimes like Indonesia, and the structure of regulatory organization DGH from regimes like Norway NPD. Neither of these countries have opted / provided for audit by Govt. auditors. Recent auditing of any specific PSC by a central government authority like CAG, is probably the first of its kind in the world.

- In PSC regimes around the world, the sovereign rights of the government are protected and investors respect that. However the PSC terms are equally respected and investor-community requests the governments to not retrospectively amend, not use ambiguities only in favor of the government. They encourage active consultation and balancing of interests.

- Lastly, at philosophical level, Govts open up Oil sector to the outside participants for considerations of attracting investment or new technology/approach and ideas. Govt. Auditors are not domain experts. Their only understanding of the oil industry is with reference through their access to the working and records of domestic state entities. On the one hand, the opening up is with the intention of trying to bring in new approach, new ideas, and new technology (something not tested tried and known domestically before).

However review of their performance by the person whose understanding and knowledge is limited and conditioned by the past, is bound to lead to differing perceptions with the auditor and auditee almost talking in two different languages. The industry is evolving and growing because of different and new ways of thinking. Geosciences are as much an art as science and world over the successes have been achieved and breakthroughs are still being achieved by challenging the notions that were held to be truism so far. An audit by Govt. agency especially of the technical decisions is thus definitional merits to be outside the scope of PSA audit.

5.6 Annexure F: Note of Dissent on ‘Chapter 2’ by Shri R. N. Choubey, Director General (Hydrocarbons) & Member-Secretary, Dr. Kelkar Committee

I am unable to agree with the recommendations of the majority of the Members of the Committee in so far as Chapter 2 relating to appropriate E&P Contracts is concerned. The reasons are as follows:

(i) The Terms of Reference (ToR) were expanded vide MoP&NG O.M. dated 10.05.2013, which included two additional ToRs. Out of the two new ToRs, the following ToR required the Committee to suggest the appropriate E&P contract model for the country:
ToR (viii) : “To give views on the recommendations of Rangarajan Committee on moving from Production Sharing Contracts to Revenue Sharing Contracts”

However, MoP&NG again subsequently modified the ToRs of the Committee vide O.M. dated 17.05.2013 by deleting the above mentioned ToR (viii). It is thus clear that it is not within the mandate of this Committee to give its recommendations about the appropriate E&P contract because that work has already been done by the Rangarajan Committee after a very elaborate exercise involving all the stakeholders.

(ii) The recommendations of this Committee in Chapter 2 are essentially based on the premise that the contentious issue of cost recovery, which is central to the Production Sharing Contract, can be successfully resolved by equating it with the methodology of corporate tax assessment. I am unable to agree with this approach because in the normal corporate functioning, the government is not involved in their day-to-day decision making. However, the Production Sharing Contract envisages significant involvement of the Government in the E&P operations of the companies through the Management Committee which, for example, approves the procurement procedures, the detailed field development plans and the annual work programme & budget. Such being the case, there will always be scope of scrutiny by other agencies to check whether the Government has discharged its responsibility properly or not and whether the costs being recovered are correct.

(iii) Many of the data, graphs, analysis and conclusions in Chapter 2 have been simply presented as findings without the writer indicating the source or the methodology, nor have they been discussed.

Under the circumstances, I dissociate myself from the whole of chapter 2 of the Report. However, since this chapter forms a part of the Committee’s Report by majority, I consider it important to present an alternative system of E&P contract which is born out of DGH’s experience in implementing the Production Sharing Contract for nearly twenty years.

An Alternative E&P Contract

1.0 INTRODUCTION

1.1 Government of India has been reviewing policies from time to time for intensifying exploration activity and attracting investment there in. In past, there had been a gradual shift in the E&P policy, from nomination acreage to competitive bidding. 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
late 90s, thereby opening the sector to all players, including foreign companies, with the aim of attracting private investment and infusing technology from all around the world. The NELP policies were formulated in a framework of progressive de-regulation in the hydrocarbon sector.

1.2 The extant flagship policies of NELP are operational through a contractual regime entered into by the Government and the Contractor for the purpose of exploration and exploitation 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 license or lease. These terms and conditions are stipulated as articles of the Production Sharing Contract (PSC). PSCs are now the dominant mode of hydrocarbon administration in the country.

1.3 As PSCs have progressed from the exploration stage to the development and production stage through successive NELP rounds, certain constraints have been observed in working of the existing contractual and fiscal model of PSC by both the Government and Contractors. Fiscal Model in the existing PSC comprises two main elements, both of which are biddable: (i) upto 100% cost recovery and (ii) sharing of profit petroleum, based on the Pre-Tax Investment Multiple (PTIM). 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. This model has the following constraints:

1.3.1 One of the objectives being the Government Take, incentivizing the exploratory work (which is expensive) is adversely affected.
1.3.2 Estimation of recoverable costs proposed by the Contractors in this “Cost Plus” Model is fraught with uncertainties leading to disputes, slower decision making etc.
1.3.3 Requires constant and micro monitoring by the Government to protect the take of Government, leading to procedural delays and regulatory overloads, both for the Contractors and for the Government.

1.4 These constraints are 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.

1.5 It was felt that there is need to revisit the Contractual and Fiscal Model and address this issue in respect of the future PSCs. Accordingly, The Government of India constituted a 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 expenditures of producers.
2. REVENUE SHARING CONTRACT (RSC) MODEL PROPOSED BY RANGARAJAN COMMITTEE

Following are the salient features of the model proposed by the Committee:

2.1 Fiscal Terms: The present basis for production sharing, i.e. PTIM and Cost recovery will be replaced with an incremental production-based sliding scale combined with a fixed, price-sensitive scale. Following fiscal components are proposed in the model:

2.1.1 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 would be continued.

Production Sharing: Revenue, net of royalty, will be shared between the Contractor and the Government using a sliding scale calculation methodology. The average of oil for the month and gas prices for the quarter will be considered for determining the price for the calculation of Government’s share of production. 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 given below.

**Illustrative Matrix Format**

<table>
<thead>
<tr>
<th>Daily Production (Mbod)</th>
<th>SHALLOW WATER OFFSHORE BLOCK (OIL CASE)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Oil Price ($/Bbl)</td>
</tr>
<tr>
<td>&lt; or = 10</td>
<td></td>
</tr>
<tr>
<td>&gt; 10 to &lt; or = 30</td>
<td></td>
</tr>
<tr>
<td>&gt; 30 to &lt; or = 50</td>
<td></td>
</tr>
<tr>
<td>&lt; or = 75</td>
<td></td>
</tr>
<tr>
<td>&gt; 75 to &lt; or = 90</td>
<td></td>
</tr>
<tr>
<td>&gt; 90 to &lt; or = 105</td>
<td></td>
</tr>
<tr>
<td>&gt; 105 to &lt; or = 120</td>
<td></td>
</tr>
<tr>
<td>&gt; 120</td>
<td></td>
</tr>
</tbody>
</table>

2.1.2 The revenue share from production 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. The numbers specified in each cell of the matrix of the winning bid
will be agreed to in the Revenue Sharing Contract (RSC) that will be signed between the Government and the Contractor.

2.1.3 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. 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.

2.1.4 **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 will be available 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), where the period of tax holiday would be for 10 years.

2.1.5 The overall bidding parameters of the Minimum Work Programme (MWP) commitment, Technical capability and the fiscal package will remain the same as in present PSC contract. Only the bid evaluation criteria for the fiscal package will change with the proposed changes in the fiscal model, although its weightage in the overall bid will remain the same.

3 **ISSUES RELATING TO REVENUE SHARING MODEL**

3.1 Although the proposed changes in contract model will lead to a simple and transparent system with easy-to-monitor parameters of production and price, the following issues may arise while administering the contract:

3.1.1 In the absence of adequate geo-scientific data in the blocks to be offered, estimation of representative production profiles may be difficult.

3.1.2 In view of the uncertainty in the prospectivity of the exploration acreage offered, estimation of revenue share would be difficult, almost amounting to gambling leading to irrational bids.

3.1.3 Since the model does not permit cost recovery, there is no incentive to explore and exploit difficult oil, undertaking IOR/EOR Schemes etc. which are costly and capital intensive in nature leading to higher cost of production.

4 **A THIRD CONTRACT MODEL**

4.1 The cost recovery available under the PSC model is the biggest incentive for the E & P companies. However, the proposed RSC model by Rangarajan Committee does not
envision any cost recovery and hence has not found favour with these companies. Hence, there is an apprehension about the likely response of the investors in the future NELP bidding rounds proposed to be launched under the RSC model.

4.2 In order to mitigate the exploration risk of the E & P contractors, a third contract model primarily based on work programme could be an option. The main objectives of this new contract model are as under:

- Attracting the best E & P companies for bidding.
- Incentivizing aggressive exploration for hydrocarbon in the country.
- Energy security being the paramount requirement, the Government Take (by way of revenue share or profit share) should not be a biddable parameter and the usual royalty, cess and taxes should be considered adequate for this purpose.
- Incentivizing the E & P Companies to invest in capital intensive activities for maximizing production, such as IOR/EOR activities, exploration and production of difficult oil etc.

4.3 The fundamental principle behind the new contract model is that in a country such as ours with uncertain prospectivity, the Government’s sole objective should be ensuring energy security of the country, rather than increasing ‘Government Take’ from the upstream sector. A higher production by E & P companies eventually results in realization of more Corporate Income Tax, Sales Tax and Royalty etc. by the Government.

4.4 In order to ascertain the ‘Government Take’ realized so far under the PSC regime, the cumulative royalties paid to the State Governments and the cumulative royalties, cess and profit petroleum paid to the Central Government on oil and gas production since inception (1994-95 till 2012-13) have been tabulated below:

*(in US$ Billions)*

<table>
<thead>
<tr>
<th>Category</th>
<th>Paid to Central Government</th>
<th>Paid to State Governments</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royalty</td>
<td>2.35</td>
<td>1.93</td>
<td>4.28</td>
</tr>
<tr>
<td>Cess</td>
<td>2.20</td>
<td>-</td>
<td>2.20</td>
</tr>
<tr>
<td>Profit Petroleum</td>
<td>10.86</td>
<td>-</td>
<td>10.86</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>15.41</strong></td>
<td><strong>1.93</strong></td>
<td><strong>17.34</strong></td>
</tr>
</tbody>
</table>

(1 US$ = Rs 60/- has been considered for conversion)
4.5 From the above, the following observations can be made:

- Out of the total of US$ 17.34 Billion paid to the Central and State Governments, Profit petroleum constitutes about 63% while the remaining 37% is contributed by cess and royalty.
- The total cumulative ‘Government Take’ of US$ 17.34 Billion realized over a period of about 18 years, working to an average of US$ 1 Billion per year, is insignificant as compared to the yearly oil import bill to the tune of US$ 150 Billion in 2012-13.

4.6 Therefore, there is an urgent need to increase domestic oil/gas production through accelerated exploration efforts to reduce import dependency, instead of emphasising on Government Take. The proposed contract model has been conceived in line with this objective.

5. SALIENT FEATURES OF THE CONTRACT MODEL

Following are the salient features of the model:

5.1 **Work Programme**: The Committed Work Programme in exploration phase will continue to be a biddable parameter as being done in the current NELP bidding.

5.2 **Technical Capability**: The proposed operator must have the requisite technical competence to undertake the committed work programme as specified under the current NELP bidding.

5.3 **Financial Capability**: The bidding companies should have the financial capability to undertake the committed work programme as specified in the current NELP bidding.

5.4 **Profit Petroleum**: No profit petroleum is payable to the Government.

5.5 **Royalty**: Royalty on oil and gas production will be similar to the existing royalty rates in NELP blocks.

5.6 Thus the only biddable parameters will be exploratory work programme and the techno-financial standing of the company.

5.7 **Contract Stability**: A suitable mechanism will be put in place upfront in a transparent manner for situations leading to windfall gains, which may otherwise lead to post-facto knee-jerk responses leading to contract instability.
6. THE ISSUE OF WINDFALL GAINS

6.1 A view needs to be taken about revenue realization by the Government in case of windfall gains realized by the contractor either due to a very large hydrocarbon find and consequent increased oil/gas production, and/or due to sudden jumps in oil and gas prices. The following options of imposing a windfall levy may be available:

Model (A): Windfall Levy on Company

6.1.1 Windfall Levy based on E & P Company’s profitability: This would be applicable for a company (or a subsidy) whose sole business is E & P activity in India. For such a company, in a particular year when the net profits based on the corporate tax returns is more than, say, 40% of the gross revenue, then a windfall levy by way of Petroleum Tax or Additional Income Tax payable to Income Tax Deptt. or Petroleum Levy payable to MoP&NG may be levied at the rate of, say, 20% on the incremental taxable income beyond 40% of gross revenue, in addition to annual Income Tax rate as per Finance Act. The proposal will require incorporation of suitable provisions in the Finance Act in case of Petroleum Tax or Additional Income Tax payable to Income Tax Deptt., and amendment to Royalty notification by MoP&NG (to be checked) if Petroleum Levy is to be paid to MoP&NG. This will encourage the E&P company to invest profits from one block in E&P activities in other blocks held by that company in India. Such a windfall levy will take care of windfall both due to price surges in a year as well as due to large hydrocarbon finds leading to large annual production. On the flip side, it would require integrated oil companies to form E&P subsidiaries which may lead to other taxation issues. Similarly, in case of joint bidding by two or more companies, either all of them would need to be E&P companies or they would have to form a joint venture E&P company.

Model (B): Windfall Levy on Block

6.1.2 Windfall Levy due to surge in oil and gas prices: In the case of a company whose business is diversified and not confined to E&P activity alone, the Windfall Levy would be applicable for annual production from a block (and not on production for the Company as a whole). The windfall levy on ad valorem basis due to price surge in a year may be levied as a percentage of incremental gross revenue and will be applicable based on weighted average annual crude oil and gas price. Somewhat similar model exists in Trinidad and Tobago only for oil and condensate production. Incremental annual revenue is the revenue accruing beyond the threshold values. Different rates may be considered for onland, shallow water and deepwater/ultra-deepwater blocks as under:
For Crude oil and Condensate Production

| Weighted Average Annual Crude Oil Price Threshold Value realised by company (US$/bbl) | Windfall Levy on Incremental Annual Revenue from oil |
|---|---|---|
| | Onland | Shallow Water | Deepwater/Ultra-Deepwater |
| 130-150 | 20% | 15% | 10% |
| >150 | 25% | 20% | 15% |

For Natural Gas Production

| Weighted Average Annual Gas Price Threshold Value realised by company (US$/MMBtu) | Windfall Levy on Incremental Annual Revenue from gas |
|---|---|---|
| | Onland | Shallow Water | Deepwater |
| 12-18 | 20% | 15% | 10% |
| >18 | 25% | 20% | 15% |

The threshold values and the windfall royalty rates can be reviewed once in five years, but only for future contracts.

6.1.3 Windfall Royalty due to large Hydrocarbon Finds: There should normally be no windfall levy on large hydrocarbon finds because:

- Such finds are a result of corresponding exploratory efforts of the E & P Company, and
- Large hydrocarbon finds, which add real value to the country’s energy security, should not be penalized.

However, if the Committee feels that not putting in place a system of windfall levy arising due to unexpectedly large hydrocarbon finds may also lead to contract instability, then we may recommend an additional windfall royalty on all incremental production of oil and gas (the latter to be converted into oil equivalent) at the rate of 20%, 15% and 10% for onland, shallow water and deep water respectively for incremental production beyond the threshold of average daily production of 500,000 barrels of oil and oil equivalent in a particular year from a block.

6.2 It may be noted that a company will have to indicate, at the time of bidding, whether it wishes to be considered for Model (A) or Model (B) for the treatment of windfall gains, should such a situation arise during contract period. However, this choice will have no bearing on the two-fold biddable parameters consisting of exploratory work programme and techno-economic standing of the company. A related issue to be discussed is whether a company which has won a block may be allowed to freely migrate from Model (A) to Model (B) and vice versa, and if so, then at what periodicity.
5.7 Annexure G: Note of Dissent by Shri S.V. Rao, Member, Dr. Kelkar Committee, on the Report (Part-I)

It is against the backdrop of my limited understanding and inability to convince all the other members of the Committee that the following is placed for consideration as contrarian viewpoints under the following heads:

1. Executive Summary: In the opening remarks the statement “little incentive for the investor to (I) goldplating (II) for wilful underproduction.” can be valid only for the PSC contracts after NELP-VI. The earlier contracts from NELP I appear to suffer from this. Given the large number of contracts signed in these six rounds, clearly solutions would need to emerge for them, which have still not found mention in the report.

2. Pt.4 of Executive Summary: It would be less than fair to agree to recommendations stated “Implement reforms related to contract administrations of existing Production sharing contracts (PSCs)” as at the outset, PSCs are legal documents. Whole scale revisions are not appropriate, particularly as some of these are currently under arbitration/dispute resolution. Additionally, the recommendations on the importance of MoPNG/DGH to restrict its involvement only to prudential and fiduciary oversight of technical dimensions over fiscal dimension appears untenable as it strikes at the very heart of the mechanism of estimating materiality of volumes and resultant government take. This is so, as it obviates the requirement of the approval processes for a host of activities in the acreage, by the other representatives of the Management Committee (DGH/MoPNG). They have been mandated and tasked to scrutinize precisely both fiscal and technical elements to ensure that interests of the Government are protected.

3. Chapter 1: Under pt. 1.2, “call to action”, there is a mention, “If we are able to bring this six billion BOE to production over the next 15 years, it would result in US $40 billion per year savings in the import bill for the Government.”

To put a perspective to this huge production expectation, it would be proper to understand that current annual oil and gas production in the country hovers around 0.65 billion barrels as per MoPNG statistics. However, the figure of 6 billion barrels BOE Incremental production over the next 15 years (A figure alluded to through AOGO and BCG inputs) would mean an average of 2.5 billion barrels per year for the next 15 years, which amounts close to four times the current production. This, to put it mildly, is a gross overstatement as a bulk of this new production is to occur from YTF or resources under development. This is all the more ludicrous in concept, as the fastest time for discovery to production attained in the NELP PSC regime was nine years. To expect that, all of the current facilities, plants and infrastructure can be replicated over four times is stretching the argument and is misleading.
4. Chapter 2: It would be fair to say that the Committee in its report has repeatedly stated that the centrality or otherwise of the type of E&P contracts to be adopted in the country is still a subject matter of study by it and final understanding and recommendation would emerge subsequently. However, the retention of the Chapter itself has perforce led me to expressly state that, in my opinion, this entire chapter need not find any place in the Part I of the report.

Pt 1.4, is titled “Current Situation on the Contractual Model”. All the issues and infirmities that occur in the current operationalizing of the contracts for acreages under NELP I to NELP VI, relate directly to the matter of gold plating which has been so vehemently opposed in the Committee report, under this and Pt. 1.6.

In Pt 1.6, I would argue that in this context, it would be worthwhile to consider third party understanding of Indian NELP PSC's (up to NELP VI). To illustrate, a report by AUPeC to the Ministry of Economic Development of the Government of New Zealand, compared the prevalent PSC contracts of six countries including India and stated that "it suffers from structural problems in the form of gold plating". Excerpts from the report are appended.

In Pt. 1.8, which discusses the economic analysis of PSCs and RSMs for both Government and operators, there is need to understand that the RSM is not yet in place, making comparisons odious. All the assumptions and statistics in this chapter as provided by AOGO and BCG are neither authenticated nor stated in terms of their model structure.

I would not hence be a party to any of the assumptions and I do believe that the pt. 1.8, has necessarily to be ignored as it does not account even for the statistics as provided by the MoPNG. To illustrate under, approach B, as on 1.4.2012, MoPNG statistics state that there are 65 oil, 158 gas and 224 oil and gas fields cumulating to 447 fields in all. This suggests that the data provided by BCG is in gross error which talks of actual 1132 Oil and Gas fields including forecast data on fields which are currently not discovered. The latter part of this statement is simply not understood as the word ‘actual’ has been used. It would call into question all the derived data on volumes etc. It would be appropriate to jettison any discussion on approach B and Pt.1.8 as a whole.

5. Chapter 3: Under 1.12, “Reforms related to contract administration of existing production sharing contracts (PSCs)”. All references to keeping only prudential and fiduciary oversight of technical dimensions over fiscal dimension cannot be agreed to as elaborated earlier.
Appendix:

Extract from a report (by Aberdeen University Petroleum and Economic Consultants, AUPEC) which says that Indian PSC incentivizes gold plating

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Evaluation of the Petroleum Tax and Licensing Regime of New Zealand

Final Report to the Ministry of Economic Development
July 2009

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- To ensure that the fiscal system does not encourage oil companies to overspend. In some circumstances the tax system may introduce incentives for investors to spend more than is necessary because the resulting tax saved is so great that the investor is better off. This is sometimes referred to as a “gold plating” incentive.
Figure 40 shows the GSB oil development economics under an Indian style production sharing contract. Other things being equal, this does not compete (lower NPVs) with New Zealand's oil taxation system. It also suffers from structural problems in the form of gold plating.

The significant increase in NPV for the largest oilfield on moving from a unit development cost of $9/bbl to one of $11/bbl, for example, is the result of the large rise in the government share of profit oil, from 28 to 85%, on entering the highest Investment Multiple band. By spending an additional $500m on development in 2009 terms, plus a proportional increase in operating costs, and despite the consequent rise in cost oil and fall in profit oil volumes, the investor can increase the value of its share of profit oil by $2.2 billion (nominal). Two years of production at 15% contractor share of profit oil are converted into one year at 50% and one at 72%.

The regime is highly progressive in terms of unit development cost, in fact too progressive, resulting in the lack of relatively high NPVs at low unit development costs in Figure 46. The erratic behaviour shown in the plots for individual field sizes is related to the finer detail of the gold plating present, that is, the design of the bands of government share of profit oil and of the Investment Multiple, as explained for one particular example when discussing Figure 46 above.
In terms of the five notional field sizes at their most likely unit development costs, the fundamental structure of the fiscal regimes can be classified as virtually proportional (New Zealand and Australia Offshore Commonwealth), regressive (Papua New Guinea) and progressive (China, Thailand and India). When considering the phenomenon of widespread gold plating as observed for India, the investor take (100% minus the above percentages) is the key factor. For this purpose, however, it is better investigated in net present value (discounted) investor take terms.

Table 15. Nominal Percentage Gov. Take, $60/bbl, Most Likely Unit Development Costs

<table>
<thead>
<tr>
<th></th>
<th>$/bbl devex</th>
<th>40 mmb</th>
<th>60 mmb</th>
<th>120 mmb</th>
<th>260 mmb</th>
<th>400 mmb</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Zealand</td>
<td>44.1</td>
<td>44.1</td>
<td>44.1</td>
<td>44.2</td>
<td>44.1</td>
<td></td>
</tr>
<tr>
<td>Papua New G.</td>
<td>37.4</td>
<td>35.1</td>
<td>34.2</td>
<td>33.7</td>
<td>33.4</td>
<td></td>
</tr>
<tr>
<td>Australia O.C.</td>
<td>59.1</td>
<td>58.2</td>
<td>58.2</td>
<td>58.2</td>
<td>58.2</td>
<td></td>
</tr>
<tr>
<td>China type PSC</td>
<td>71.0</td>
<td>71.9</td>
<td>72.4</td>
<td>74.1</td>
<td>75.6</td>
<td></td>
</tr>
<tr>
<td>Thailand</td>
<td>62.5</td>
<td>68.3</td>
<td>71.0</td>
<td>76.2</td>
<td>78.7</td>
<td></td>
</tr>
<tr>
<td>India type PSC</td>
<td>76.4</td>
<td>78.4</td>
<td>79.2</td>
<td>85.9</td>
<td>84.9</td>
<td></td>
</tr>
</tbody>
</table>

In terms of the five notional field sizes at their most likely unit development costs, the fundamental structure of the fiscal regimes can be classified as virtually proportional (New Zealand and Australia Offshore Commonwealth), regressive (Papua New Guinea) and progressive (China, Thailand and India). **When considering the phenomenon of widespread gold plating as observed for India**, the investor take (100% minus the above percentages) is the key factor. For this purpose, however, it is better investigated in net present value (discounted) investor take terms.

5.8 Annexure H: Response of the Chairman of the Committee to the Dissent Note by Shri.S. V. Rao

**Response to Point 1 and 2:**

'Government take' in the context of Oil and Gas comprises of royalty, cess, corporate tax, and profit petroleum share. These collectively form the 'fiscal interest' of the government. In principle, the basis for computation of profit petroleum under the PSC is similar to the computation of taxable profit under the Income Tax Act. However, for computation and oversight of corporate tax, which is a part of government take, the government does not get involved in the day to day operations and business decisions of the firm. Given the alignment between the government's and contractors' interest under the PSC system, "prudential and fiduciary oversight" for optimal utilization of the country's hydrocarbon resources should be afforded greater emphasis by the DGH than the fiscal dimension. As provided in the PSCs, the Contractors are expected to adopt Good International Petroleum Industry Practices (GIPIP) while developing discoveries and the DGH should focus on ensuring such adherence. The fiscal dimensions, including computation of profit petroleum, should be under the purview of the revenue authorities.
Response to Point 3:

There is a major error in the calculations by Dr. S. V. Rao regarding the annual production figures. He has calculated additional annual production figures as 2.5 Billion Barrels per year for next 15 years. This is widely off the mark. The Report is talking of producing 6 Billion Barrels over the next 15-year period. That will mean the country producing additional 0.4 Billion Barrels per year as compared to the present annual production of 0.65 Billion Barrels of the ONGC alone. The Committee believes that such an increase is achievable given international experience of the countries achieving similar or even higher levels of increase and our own experience of the ONGC achieving a spectacular increase in Bombay High production.

Response to Point 4:

The New Zealand study mentioned by Dr. Rao is rather dated. A more recent 2013 study by the IMF staff, where it compares India’s present PSC contract vis-à-vis the proposed Revenue Sharing Model and supports the analysis of the Committee.

Further, the New Zealand Study is also conceptually weak as there is no mention of “risk” or “uncertainty” in their model. This is a major shortcoming as the defining feature of Exploration and Production of oil and gas is the profound uncertainty in estimating production, prices and revenues from underlying oil and gas reserves.

As far as the issue of a number of fields used for our “Forward-Looking” analysis is concerned, the source of the BCG data is the Rystad Global Database, a respected international oil industry Database. Their data include forecast or estimates for the fields which are yet to be developed. In any case, the conclusions will not differ qualitatively if an analysis is restricted as the MoPNG data for 447 producing fields.