THE OXFORD INSTITUTE FOR ENERGY STUDIES

March 2018

# Policy Considerations Around India's Upstream Reforms

OIES PAPER: WPM 78

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ISBN 978-1-78467-105-1

DOI: https://doi.org/10.26889/9781784671051

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## 1. Introduction[1]

India's government is attempting to revive investments in its upstream sector, following several years of decline. In May 2016, it ran a 'Discovered Small Fields' (DSF) auction of marginal fields held by its National Oil Companies (NOCs), and in July 2017 launched its first open acreage licensing round under its new 'Hydrocarbon Exploration Licensing Policy' (HELP), which changed the upstream fiscal regime, going forward, from a profit-sharing to a revenue-sharing model.[2] These efforts are related to achieving a policy objective of reducing energy imports by 10 per cent over current levels by 2022 (PIB, 2017a).[3]

A previous OIES Insight underscored the challenges related to this goal. India's oil consumption, which grew at an average annual rate of 4.8 per cent per annum between 2005 and 2015, stood at roughly 4.5 million barrels/day (mb/d) (or around 213 Million tonnes, Mt) in 2016, with 81 per cent of this sourced from imports (BP, 2017). In contrast, production was around 856 thousand barrels/day (kb/d) (40.2 Mt) in 2016, growing at a much slower average annual rate of 1.7 per cent over the period 2005–15 (BP, 2017). A 10 per cent reduction in imports by 2022 from 2016 levels would entail increasing production by around 363 kb/d (17.2 Mt), a rise of about 42 per cent from current levels.

However, India's likely future growth in oil demand to 2022 (forecast at just over 240 Mt),[4] implies that implementation of the 10 per cent reduction could equate to a higher requirement of 20.2 Mt (over 400 kb/d) of incremental production by 2022 (around 50 per cent higher than current levels); this would result in an oil import dependency of around 74 per cent of consumption. The DSF round, in comparison, is estimated to add 15 kb/d of domestic production at peak levels – contingent upon companies achieving the production targets proposed in their winning bids – generating roughly ₹143 billion (US$2.2 billion) in government revenues (PIB, 2017a;b). Although a second DSF round is proposed, these quantities are unlikely to make more than a dent in India's oil import requirements (Platts, 2017).

Given the proximity of the 2022 target, other models are being considered. The majority of licensed acreage (around 65 per cent of 214,881 km$^2$) is estimated to be held by the NOCs, with around 60 per cent of this held by Oil and Natural Gas Corporation (ONGC) (Sen, 2016). India's government is exploring options to increase production from NOCs' acreage, through contracting external capital and expertise and/or releasing some of this acreage for development. Roughly a third of acreage held by ONGC and 10 per cent held by Oil India Limited (OIL) falls under India's 'nomination regime' – granted by the government to the NOCs, prior to upstream liberalisation in the 1990s (Sen, 2016). There is a contention that much of this has remained undeveloped, partly as it was deemed marginal to the NOCs' operations, and partly due to technical constraints (TH, 2017a). Nomination acreage – which was the earliest prospective acreage identified by the NOCs – is also seen as containing some of the country's more valuable producing assets. This paper contributes to the policy discussion by addressing the following questions: what are the lessons from India's previous bidding rounds for upstream acreage (specifically the NELP[5] and DSF rounds, over the period 1999-2017)? And, what are some of the policy considerations, given similar international experience?

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[1] The author is grateful to Rob Arnott, Carole Nakhle, Damilola Olawuyi, Fluvio Alarcon, Bassam Fattouh, and to numerous colleagues in India, for providing useful insights and comments, and to Kate and Catherine for their support with production.
[2] See Sen (2016; 2017) for details.
[3] 'Energy' is largely taken to imply oil, which forms 80% of India's energy imports. (TH 2017b; BP, 2017)
[4] See IEA (2016). The New Policies Scenario considers current trends in oil demand growth as well as policy measures announced by the government related to oil in the energy mix.
[5] New Exploration Licensing Policy – the profit-sharing fiscal regime under which blocks were auctioned from 1999 to 2009.

## 2. Past experience

India can draw from some of its past experience in upstream activity to identify key lessons around designing upstream policy. Based on prior literature analysing the outcomes of oil and gas auction rounds in India covering the 'Pre-NELP',[6] 'NELP', and 'Discovered Small Fields (DSF)' rounds, two issues have repeatedly arisen: entry criteria and 'gaming' of the fiscal terms.[7]

### 2.1 Entry criteria

This relates to the level at which entry barriers should be set for companies seeking to enter the auctions. Policymakers face the conundrum of setting pre-qualification criteria at levels which encourage healthy participation in the bidding rounds, yet which adequately ensure that those companies participating can deliver on their work programmes, should they go on to win. This is particularly difficult to ensure in bidding rounds for small and marginal fields, in instances where policymakers may be attempting to attract oil companies other than service companies.[8]

Consequently, in previous rounds, first-price sealed bid auction processes have been susceptible to the 'winner's curse' – a situation where the winner of the auction discovers that it may have overpaid for a lease when the second-highest bid is revealed to be relatively low. The difference between the winning bid and second-highest bid is an indicative measure of the extent of overbidding (Iledare et al., 2004). The *ex post* implications (for example production delays) of overbidding have greater significance when awards are based purely on work programme commitments and do not include a large upfront payment or signature bonus, as the winning bidder may be unable to fulfil work programme commitments, thereby also delaying revenues to the government. The acreage then has to be 'recycled' in future auction rounds, potentially negatively impacting upon new bidders' perceptions of its 'prospectivity'.[9]

Quantification of overbidding has been attempted in the literature using the dispersion in bid levels in and between auction rounds; this is also referred to as 'money left on the table' and can be conceived as the percentage difference between the high bid and the second-highest bid on a lease which attracts multiple bidders (Haile et al., 2010). For instance, although data on the monetary value of bids is unavailable for India's NELP auctions, differences in the total 'scores' awarded to the highest and second-highest bids on blocks can be used as a notional measure of dispersion. Table 1 below shows the percentage of blocks receiving more than one bid in the first row, and the average (median) difference between the highest and second-highest bid (scores) in the second row, for five of the nine NELP rounds for which data was available.

**Table 1: Notional measure of 'overbidding' in past rounds**

| | NELP II | NELP IV | NELP VI | NELP VII | NELP VIII |
|---|---|---|---|---|---|
| **Blocks with multiple bids (%)** | 38 | 61.54 | 72.22 | 13.92 | 22.86 |
| **Median Overbid (%)** | 47.90 | 28.67 | 19.07 | 9.96 | 11.90 |

Source: Sen and Chakravarty (2013)

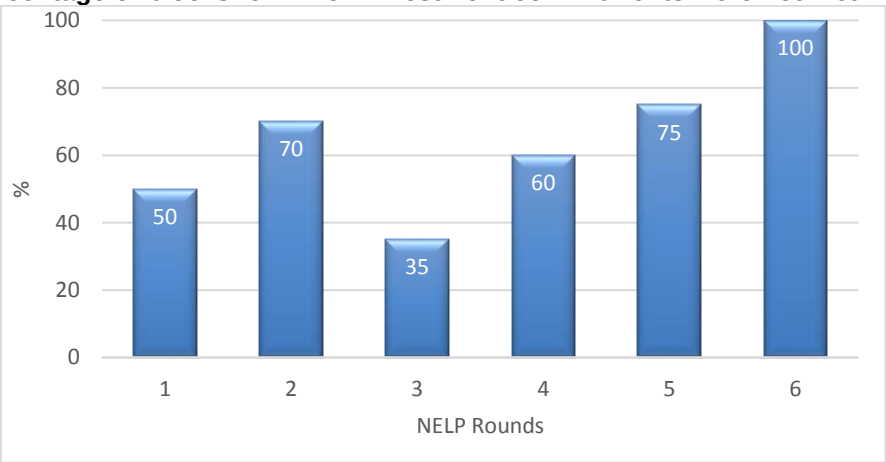
For instance, the second row of Table 1 (median overbid) implies that half of the winning bidders on blocks with multiple bids bid at least 48 per cent more than the second-highest bid in the second round

[6] Pre-NELP refers to auctions for 'Discovered Fields' in the early 1990s.
[7] Sen (2016; 2017) and Sen and Chakravarty (2013) set these out in greater detail based on prior oil and gas auction rounds and the multiple fiscal regimes governing them.
[8] Service companies tend to operate on business models based on lower risks and on managing margins. This model is, however, changing; for example, Schlumberger has reportedly been buying stakes in its customers' oil and gas projects (Reuters, 2017).
[9] A term used to describe the likelihood of whether an area contains reasonably recoverable hydrocarbons.

of the NELP auctions (NELP II). Although there are no benchmarks to determine the extent of overbidding in the NELP rounds, authors of international empirical studies have considered levels ranging from as low as 9 per cent to as high as 60 per cent to be indicative of overbidding (Jayasena and Uhanowitage, 2008; Haile et al., 2010; Klemperer, 2004). In comparison, in the US Outer Continental Shelf (OCS) auctions, the amounts of 'money left on the table' are fairly constant across different auction rounds – not just for tracts which received more than one bid, but also in the cases of tracts which received more than 10 bids. Thus, these amounts do not vary significantly with changes in the number of bids received for blocks, suggesting that the dispersion between the highest and second-highest bids for the OCS auctions may be attributable to differences in bidders' true values, rather than to overbidding (Haile et al, 2010).[10]

Overbidding can also be indicative of 'speculative bidding' – bids made with the main intention of increasing the value of a portfolio, particularly during times of high international oil prices. The risk to a government with overbidding is that the winner may seek a renegotiation of terms (Nakhle, 2015). This has been flagged up as a concern in the Indian hydrocarbons sector, particularly with respect to 'aggressive' bidding by non-specialist firms for smaller exploration blocks.[11] It was, for instance, alleged by some international majors that in the bidding rounds for NELP VI, some bidders offered speculative bids on fiscal terms which in theory would have led to returns that were lower than those from 'risk free' investments, such as government bonds; it was also alleged that some of these fiscal bids may have been made purely to win fields, with the intention of renegotiating terms *ex post* (Sen and Chakravarty, 2013; FE, 2006). This may have been partially reflected in the percentage of blocks for which investment commitments were not met – shown in a government committee report on resource allocation in 2011 (Figure 1; Figure 2). Tordo et al. (2009) argues that an efficient allocation system needs to ensure that blocks are awarded to companies that submit the most appropriate bids, not necessarily the most optimistic ones.

**Figure 1: Percentage of blocks for which investment commitments were not met in 2011**




Source: Draft of Ashok Chawla Committee Report on Natural Resource Allocation (ACCR) (2011)

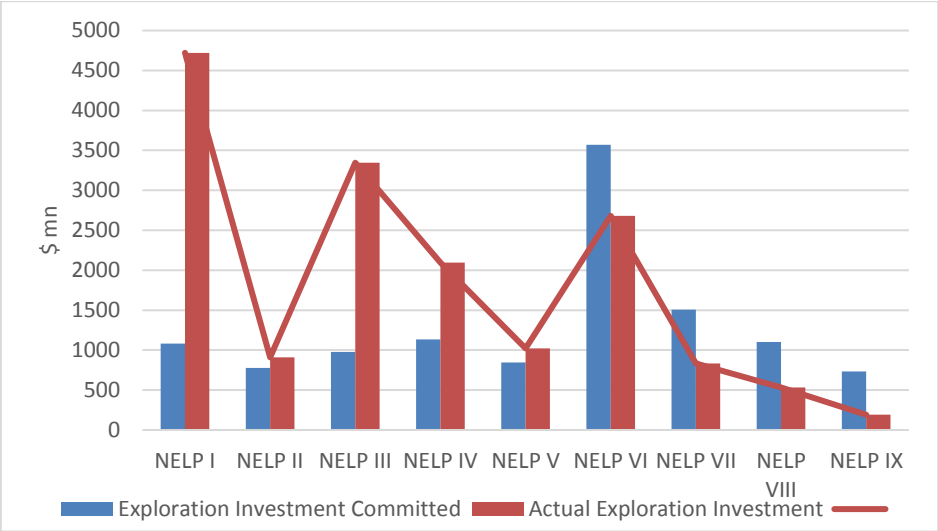
India introduced penalties – referred to as 'liquidated damages' – for unfinished work programmes in the eighth round of the NELP auctions, in an attempt to address this concern. However, the literature on auctions suggests that if penalties are not set substantially high, bidders may simply adjust their bids to include these costs. Thus, if the costs of defaulting on commitments are small, bidders end up bidding (and paying) for '*options* on prizes rather than the prizes themselves' (Klemperer, 2004). Liquidated

[10] However, it should be noted that the US-OCS auctions also utilise reserve prices.

[11] For instance, in NELP VIII a very high number of wells in proportion to the area of the block was bid for several smaller 'S' type blocks – examples include 10 wells for a block (CB-ONN-2009/2) with an area of 68 square kilometres and 12 wells for 'CB-ONN-2009/3' which was 90 square kilometres.

damages for unfinished work programmes since the eighth NELP round have been set at $1 million, $3 million, and $6 million for each onshore, shallow water, and offshore development or appraisal well committed in the winning bid. These figures are a fraction of the total cost of drilling a well, and in many cases may not offset the total expected gross revenues from the failure to achieve commercial production.[12]

**Figure 2: Estimated investments made in NELP blocks**




Source: DGH (2016)

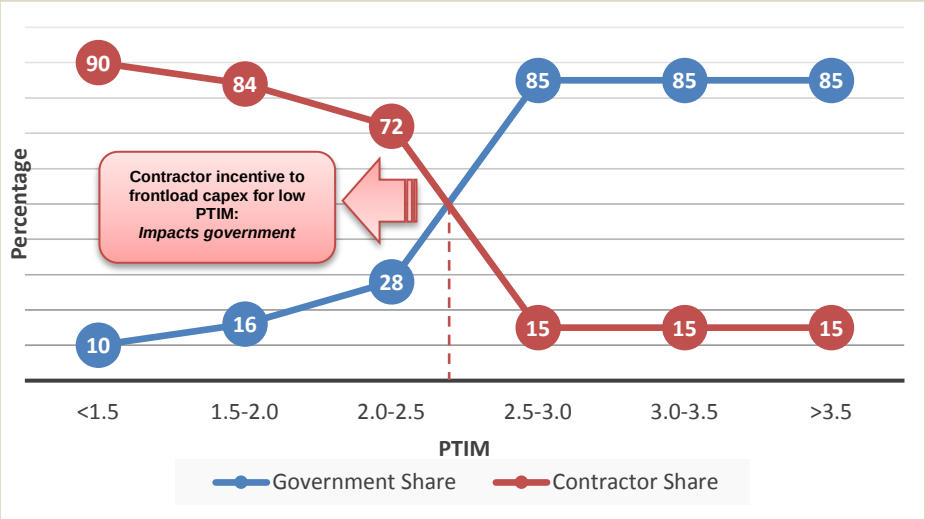
## 2.2 'Gaming' of the fiscal terms

The second concern repeatedly brought up in the NELP rounds is the 'gaming' of fiscal terms; this refers to a situation where firms modify their investment behaviour in order to postpone the sharing of proceeds from production with the government on the basis of an agreed metric (ACCR, 2011). India's NELP regime rounds 1–6 specified the sharing of profits from production with the government following the recovery of costs (up to a specific percentage proposed by the contractor) in a proportion based on a ratio of cumulative capital expenditure to cumulative cash flow (the Pre-Tax Investment Multiple, PTIM). The proportion of profits to be shared with the government was a biddable parameter, along with the annual cost recovery cap. Figure 3 below provides an illustration of the incentive for 'gaming' under the PTIM which, if observed to be true, would impact primarily upon government revenues through the postponement of profit sharing.

The PTIM was changed from six predefined slabs to a linear scale with one lower (1.5 and below) and one higher (3.5 and above) tranche for NELP rounds 7–9, which made gaming much more difficult but could not rule it out completely – particularly as it was incumbent upon companies to bid the profits to be shared at each tranche (ACCR, 2011). The Comptroller and Auditor General of India (CAG) published an audit of 22 NELP Production Sharing Contracts in August 2011, in which it was claimed that revenues had been lost to the exchequer due to poor *ex post* enforcement, particularly in relation to the monitoring of capital costs and profit-sharing (CAG, 2011).

[12] The cost of drilling a well was estimated to be as high as $150 million in Sen and Chakravarty (2013). For the DSF rounds, total gross revenues were estimated at $7 bn, or ₹465 bn (PIB, 2017a;b).

**Figure 3: Illustration of 'gaming' under the NELP PTIM**

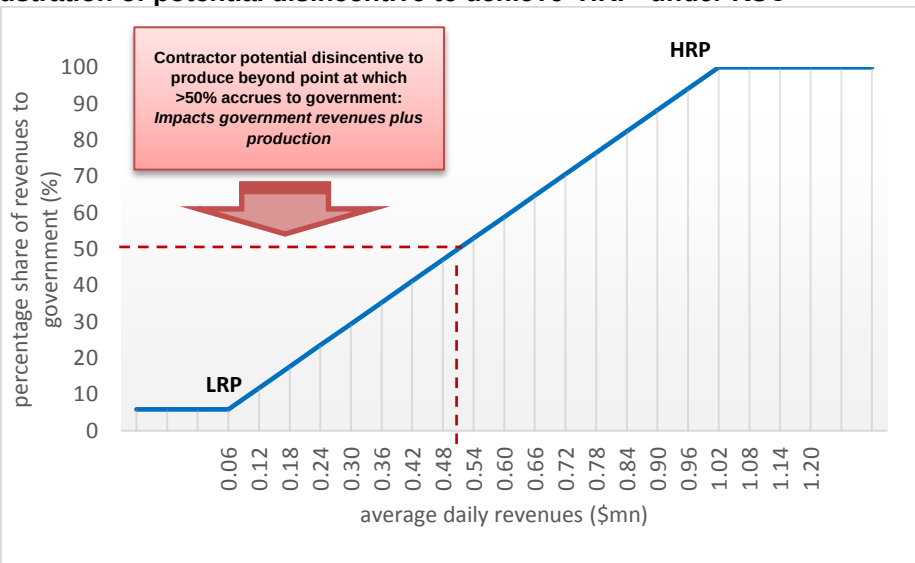



Source: ACCR (2011)[13]

To address this, India's new HELP regime brought in a Revenue Sharing Contract (RSC) to replace the Production Sharing Contract (PSC). The RSC is based on the sharing of production (gross revenues) with the government – eliminating cost recovery and removing the need for close monitoring of contractors' costs and profits. Bids in the DSF rounds were based on RSCs and evaluated on two parameters:

- *fiscal* (the Net Present Value of government revenues yielded through the percentage revenue shares bid at a lower and at a higher point by the company) – this had a weighting of 80 points,
- *work programme* (the number of development and/or appraisal wells committed by the company) – this had a lower weighting, of 20 points.

**Figure 4: Illustration of potential disincentive to achieve 'HRP' under RSC**




Source: Author's assumptions

[13] Assumptions in ACCR (2011: 48–50). Based on 90% cost recovery.

Under the *fiscal parameter*, companies were required to bid the percentage of revenues that they would share with the government at a predefined 'Lower Revenue Point' (LRP) of US$0.01 million/day and at a 'Higher Revenue Point' (HRP) of US$1 million/day. The LRP of US$0.01 million/day equates to US$3.65 million/year and, at an oil price of $50/bbl, production of around 200 b/d. The HRP similarly equates to US$365 million/year and, at US$50/bbl, production of 20 thousand b/d. The revenue share to the government at points between the LRP and HRP was worked out on a linear formula, to ensure that a continuous share of average daily revenues from production accrued to the government. Figure 4[14] shows that although the RSC is administratively much simpler, it does not entirely exclude the possibility of 'gaming'. Companies could bid a high HRP to win auctions, but it remains incumbent upon them (barring any penalties) to achieve a higher production level. The disincentive to achieve a level of production that results in foregoing the majority of revenues to the government could impact not just upon government revenues, but also on production levels. It should be noted that two government-constituted committees – the Rangarajan Committee and the Kelkar Committee – made conflicting recommendations on adopting RSCs versus continuing with PSCs. While the former argued that RSCs addressed the administrative difficulties that India has had with upstream contracts, the latter argued that PSCs provided a more suitable risk–reward structure, particularly for exploration areas. From an investment point of view, the broad consensus in the literature is that profit-based mechanisms are progressive whereas revenue-based mechanisms are regressive.[15]

## 2.3 Key issues for ongoing reforms

The reforms being considered by India's government aim at adopting an Improved Oil Recovery (IOR) and Enhanced Oil Recovery (EOR) policy which incorporates measures to boost production from marginal fields (Abdi, 2017).[16] A 2017 study, for instance, estimated that the use of EOR could potentially increase output by 45 per cent (DTTI, 2017). The same study estimated a broad extraction cost ranging from $20 to $70/barrel for EOR carried out with $CO_2$, and $30–$80/barrel for other EOR techniques, with a lead time to production of five to eight years. As EOR techniques are applied to existing wells, exploration risks are lower. The effect of investments taken to enhance recovery is to multiply the volume of remaining recoverable reserves by a fixed factor (determined by reservoir characteristics and technology) (Smith, 2012). There are two aspects to be considered in relation to the formulation of EOR policy on marginal fields.

The first relates to the definition of a 'marginal' field, and whether this pertains to size, resources, production, costs, revenues, or to some combination of all of the above. The Society for Petroleum Engineers (SPE), for instance, defines the term 'marginal fields' as referring to 'discoveries which have not been exploited for long, due to one or more of the following factors:[17]

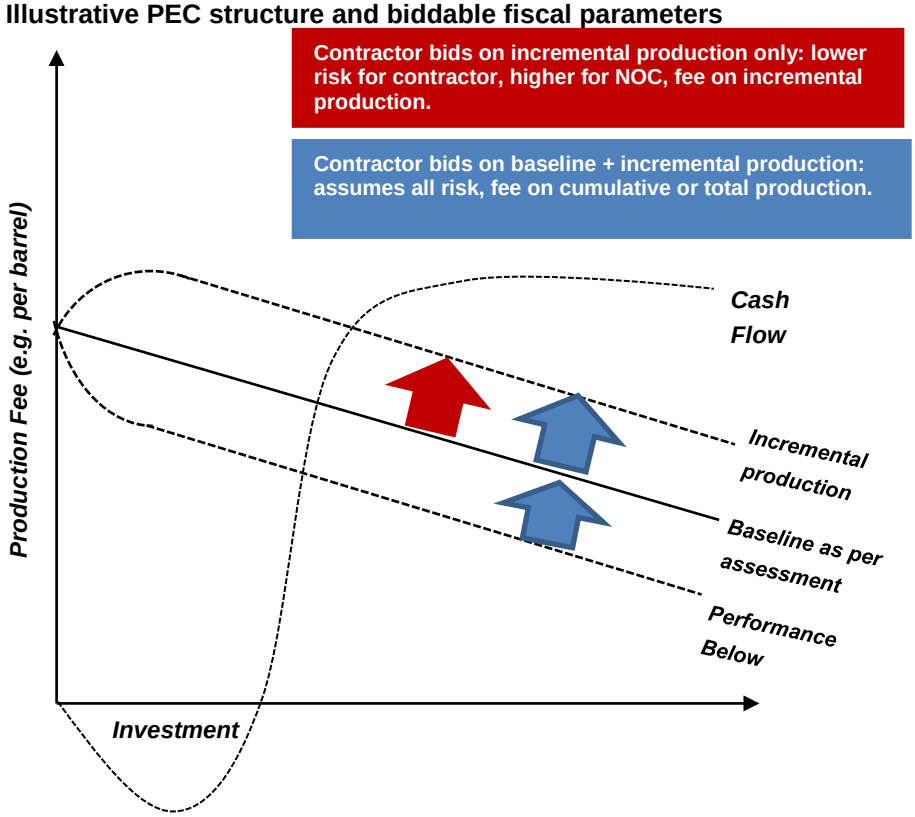
- Very small sizes of reserves, to the extent of not being economically viable;
- Lack of infrastructure in the vicinity and [lack of] profitable consumers; and,
- Prohibitive development costs, fiscal levies and technological constraints.'

It further states that 'should technical or economic conditions change, such fields may become commercial fields.'[18] In practice, the definition and selection of marginal fields is largely incumbent upon

[14] Figure 3 is based on a simple assumed revenue profile which grows linearly over a 25-year period. The LRP revenue share to the government (based on revenues of $0.01 mn and below) is assumed to be 5.9% and the HRP (based on revenues of $1 mn and above) is 94.1%.
[15] Also see Johnston and Johnston (2015).
[16] IOR strategies (referred to as 'secondary' techniques) are applied to recover mobile oil that remains in the reservoir after the application of primary recovery techniques. EOR strategies ('tertiary' techniques) are used to recover immobile oil that remains in the reservoir after application of 'primary' and 'secondary' techniques.
[17] See 'Field Developments and Technical Solutions – Marginal Fields', Society of Petroleum Engineers.
[18] Ibid.

the government (or its designated agency).[19] Further, access to infrastructure forms an important part of this definition, as it could imply that investments are needed for the augmentation of infrastructure, or alternatively, that access is needed to existing infrastructure facilities.

**Figure 5: Illustrative PEC structure and biddable fiscal parameters**




The second aspect is the contractual process through which to administer the policy. One method of promoting IOR/EOR that has been attempted in other countries involves a Production Enhancement Contract (PEC), which could be tendered out through competitive bidding,[20] with the winning contractor incentivised to boost production in return for performance-linked compensation. A baseline level of production for a marginal field may be specified, which is assumed to follow a non-linear decline curve over the remaining life of the field. Bidders may then be invited to submit field development plans for the amount of incremental value (namely incremental production, or improved recovery factor) that they would bring in as contractors, with the highest bidder awarded the tender to take over field development. Under a 'vanilla' PEC, the winning contractor is typically remunerated with a fee per barrel of incremental production or in relation to value added. Most countries also allow some recovery of costs. Figure 5 provides an illustrative example of PEC design and the associated risk–reward structures.[21]

However, the typical PEC structure throws up specific issues; failure to resolve these could potentially lead to *ex post* dispute:

- ***Defining the baseline:*** This relates to how the baseline production level (over which any increment will involve a payment to the contractor) is defined and by whom (the NOC, contractor, or some third party). Notably, the baseline may apply not just to production, but to an entire spectrum of

[19] See UN Resolution 1803 (XVII), 1962, on states' permanent sovereignty over natural resources http://legal.un.org/avl/ha/ga_1803/ga_1803.html .
[20] Generally acknowledged as the most transparent method of allocating rights (Nakhle, 2015).
[21] The figure depicts non-linear decline curves for simplicity.

activities involved in the contract, including costs and revenue shares. A failure to achieve clear definition and agreement on the same throws open the possibility of *ex post* disputes among the parties to the contract.

- ***Dealing with variations in the baseline:*** If the baseline is found to be lower than expected upon commencement of operations (for example, the reservoir underperforms), an issue may arise as to whether remuneration is adjusted downwards or not.
- ***Remuneration mechanisms:*** Another issue relates to adjustment mechanisms – whether remuneration should be a fixed fee per unit of production, or vary with oil price movements. This may be less important in resource-rich countries where contractors may be able to anticipate higher production volumes with a reasonably high degree of certainty, based on higher reserves.
- ***Reserve assessment:*** If additional reserves are found upon commencement of operations, this could raise issues around whether they accede to the NOC or are incorporated into the PEC framework in some way.
- ***Risk sharing:*** Finally, the design of PECs needs to address fundamental issues of risk sharing and the risk–reward structure for the NOC and contractor, to ensure that both are closely aligned on the objective of increasing production, or in other words, that both place the same time value of money on the revenue stream (Land, 2009).

Some suggested options to address the above issues include:

- Companies could be required to bid on the baseline as well as the incremental production, thereby assuming all risk. This may not, however, be necessarily attractive to companies if the fields being offered up can be easily written off at the outset by a farmor (that is, fields are not of adequate scale). Such a structure may also require access to data on acreages *ex ante*, potentially requiring a NOC to provide details on previous operations at the bidding stage.
- The remunerative fee to the winning contractor could be paid on total or cumulative production rather than on incremental production, thereby pre-empting *ex post* disputes related to the assessment of incremental production. However, the specific incentive to the contractor to then increase production substantially over a baseline level may be obscured.
- The winning contractor could be offered participating equity interest in the acreage, on terms that are acceptable to the NOCs to bring the incentives of the contractor in line with the incentives of the NOC (to optimise production from the field). However, this involves ensuring that fields which could genuinely add to production levels with capital and technical expertise are tendered.

**Table 2: Options reportedly being considered for production enhancement**

| Farmout | Technical Services Contract |
|---|---|
| ***Bidding criteria:*** Total investment committed and revenue share offered to the government, in equal weight.<br><br>***Equity stake:*** (Up to) 60 per cent to contractor. Any expense beyond investment committed to be shared proportionately (e.g. 60:40).<br><br>***Operational terms*****:** 20 years, or remaining life of field. 2-yr technical assessment. Field handed over to contractor in second year of second phase. Royalty rate as under HELP. No 'cess' | ***Bidding criteria:*** Tariffs for increasing output over baseline level.<br><br>***Operational terms*****:** 15-year TSC; contractor paid tariff for incremental output. |

Source: Ranjan (2017a)

The Indian government has reportedly been considering two models – a Technical Services Contract (TSC) and a Farmout structure – to enhance production. Table 2 shows the terms being considered under each model. The government reportedly surveyed roughly 200 marginal fields from the nomination acreages of the NOCs, using a composite indicator comprising several objective criteria; these were understood to include: 'cut-off' reserve volume, 'exploration index', current recovery rate, and average production decline rates. Of these, between 11 and 15 were reportedly shortlisted for farmouts, on the basis of a score of over 50 per cent on the composite indicator, whereas 44 fields were shortlisted for TSCs (Ranjan, 2017a; 2017b).

Both options have raised varied arguments – both in favour and against.[22] But at a fundamental level, India's previous experience with upstream policy suggests that any optimal policy option needs to square three (sometimes conflicting) features: it needs to be **economically efficient**, **simple to administer**, and **politically acceptable** (see Table 3).

- **Economic efficiency:** This entails the use of fiscal instruments which avoid investment and production distortions,[23] and which are also consistent with the government's petroleum sector policy. Fiscal regimes for oil are characterised by the presence of resource rents – in other words, a surplus after the payment of all costs, including an investor's risk-adjusted required return on investment (Rate of Return, ROR). One view of economic efficiency holds that since rent is a surplus, it can in theory be taxed without creating distortions (Goldsworthy and Zakharova, 2010). Economic efficiency in the capture of rent could, in theory, be achieved at the outset by selecting the most efficient operator to extract resources in the long run. Tordo et al. (2009) states for instance that allocation systems inducing bidders to offer work programmes which exceed what ordinarily would be required to efficiently explore blocks, will ultimately reduce the economic rent; this may result in future renegotiation to remove uneconomic commitments. Goldsworthy and Zakharova (2010) summarise the desirable features of an economically efficient fiscal regime as one that optimises the following parameters: neutrality,[24] the capture of rents, stability and timing of revenues, progressivity[25] and adaptability,[26] and international competitiveness.
- **Administrative simplicity:** Low administrative and compliance costs minimise the transaction costs to all parties involved – the government, NOC, and contractor – as transactions may absorb part of the rent that would otherwise accrue to the government (Tordo et al., 2009). A clear definition of the objective(s) that a government intends to achieve through the allocation system minimises transaction costs and aids in the effective design and implementation of the system. Limiting the number of biddable variables also aids administrative simplicity.[27] Another way to promote administrative simplicity is for fiscal incentives to be applied and assessed on a well-defined and familiar (for example tax accounting) basis rather than on a cash flow basis, taking into account the regulatory oversight capabilities of the state.
- **Political acceptability:** In order to minimise *ex post* disputes, upstream fiscal policy needs to ensure that the government (and the NOC) has the ability to capture its fair share of the fiscal (and technical) benefits that accrue from resource extraction in both 'good' times and 'bad', in a way that does not undermine the stability of investment (Land, 2009). It should generally support the role of the state as custodian of resources.

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[22] See ET (2017), for example.
[23] In economic terms, this refers not just to technical efficiency (amount of output per unit of input) but also allocative efficiency (the optimal mix of inputs versus output).
[24] The fiscal instrument(s) adopted should leave the pre-tax ranking of a possible investment outcome equal to the post-tax ranking (Tordo et al., 2009).
[25] Providing for a rising government take as the project's profitability increases.
[26] A system that responds flexibly to changes in prices and costs might be perceived as more stable.
[27] A maximum of two biddable parameters is suggested (Nakhle, 2015); the USA for instance utilises only one biddable parameter in its OCS lease auctions, which is the signature (cash) bonus. However, context is important. For instance, the US lease auction market is well developed and highly competitive.

**Table 3: Desirable characteristics of India's upstream policy**

| | Features |
|---|---|
| ***Economically efficient*** | Avoids investment and production distortions. |
| ***Administratively simple*** | Transaction costs are low; fiscal levies are on a well-defined and easily monitored tax base. |
| ***Politically acceptable*** | Enables the government and NOC to share in the upside of projects; supports the government's role as custodian of the resource. |

Source: Author

The literature on upstream fiscal systems for hydrocarbons proposes a number of fiscal instruments that can be used in different combinations, meeting different policy objectives.[28] Further, despite the distinction that is often made between 'concessionary systems' (or royalty/tax systems) and 'production sharing' systems, and not taking into account their different theoretical underpinnings,[29] there is broad consensus in the literature that either of these systems can be effectively designed to produce the same fiscal outcomes (see Johnston and Johnston (1994) for illustrative examples) – for example with regard to obtaining a similar level of government take. The next section qualitatively summarises important policy considerations for India's upstream reforms against the context outlined above, based on international experience.

## 3. Policy considerations based on international experience

The low oil price environment following mid-2014 catalysed a 'retreat to the OECD' of major international oil companies, reflected in an increased focus on their core assets and in the slashing of upstream capital expenditure. For instance, capex in global oil production, including greenfield and brownfield projects and maintenance, recorded annual growth of 11 per cent between 2010 and 2014, hitting a record $520 billion before the oil price crash, but by 2016 this had declined by over 60 per cent (Kutsal and Fang, 2016). This 'retreat' may also have been partly brought on by a perception of heightened geopolitical and fiscal risks in non-OECD countries. In OECD countries, marginal field rounds have targeted the maximisation of economic recovery from existing fields in which production may have peaked (such as in the UK). In non-OECD countries marginal fields can, however, often be seen as 'loss leaders' – namely investments that could lead to a bigger prize, such as a foothold in a growing market.

The fiscal and contractual frameworks used to enable production enhancement globally have ranged from Technical Service Contract (TSCs) and Risk Service Contracts (RSCs), to farmouts. For instance, *Iraq* has used three different versions of Technical Service Contracts (Ghandi and Lin, 2014):

- 'Producing Field' TSCs awarded on fields with production prior to the start of operations,
- 'Production and Development' TSCs awarded on fields with no production before the start of contracts,
- a service-type framework for exploration.

In 2009, Iraq undertook a series of licensing rounds for the development of its giant southern oil fields – the first time that 'Foreign Oil Companies' (FOCs) had been invited to work in the country since the

[28] These are not the sole focus of this paper, but readers can refer to Tordo (2007) for a comprehensive survey.
[29] See Mommer (2001).

nationalisation of the oil industry in 1972 (Alsaadi, 2017). Four licensing rounds were conducted between 2009 and 2012; TSCs for 12 oil fields were awarded in the first two rounds and for three non-associated gas fields in the third round (Ghandi and Lin, 2014). Fourth round licences covered largely undeveloped fields, in contrast to the earlier licensing rounds in which many of the fields had been, at least in part, developed.

Similarly, *Iran*'s earlier buyback contracts are similar to the RSCs used for marginal fields. The new Iran Petroleum Contract is a modified version which aims to address the deficiencies of the old buybacks (Dentons, 2016).[30]

In *Mexico,* following the expropriation of the oil sector in 1938 (see CRS, 2015) and the creation of *Petroleos Mexicanos* (Pemex), the oil sector relied on private contractors and even made use of RSCs until 1958, when a Petroleum Law expressly prohibited compensation based on a percentage of production, participation, or results of exploration. Oil service contracts were limited in scope to fixed cash payments for the performance of specified services (Samples and Vittor, 2012).[31] Reforms in 2008 resulted in Integrated Service Contracts (ISCs) – also referred to as performance-based contracts – partly targeted at developing the 30 per cent of reserves which lay in 'mature' fields (IHS, 2011). Following the 2013 energy reform, Pemex targeted the 'farmout' of at least 10 assets in a December 2014 plan (Lara, 2017). It awarded the contract for a farmout agreement for the Trion deepwater field in December 2016,[32] and two contracts for onshore mature fields, Cardenas-Mora and Oggario (Pemex, 2016).

*Brazil* carried out 13 auctions for exploration blocks from 1997 to 2016, including one bidding round for pre-salt areas, under a PSC regime, and three rounds for 'marginal accumulations' (in 2005, 2006, and 2015) under a concessions regime. In February 2013, Brazil's National Council for Energy Policy (CNPE) issued Resolution No. 01/2013 covering incentives for the involvement of small and medium-sized players in the upstream sector. The Resolution mandated that the ANP[33] must hold annual bidding rounds focused on blocks in mature basins and inactive areas with marginal fields (Braga and Campos, 2012). In 2017, the government held a fourteenth bidding round for concessions, a second and third round for PSCs, and a fourth round for marginal accumulations.

In 1996, the federal government of *Nigeria* developed contractual terms for marginal fields and amended its petroleum legislation to encourage the participation of 'indigenous' oil companies in the Nigerian oil and gas industry, (Amaza et al., 2017). Marginal fields were defined as oilfields found in IOC concessions, not containing significant oil discoveries, and with no production for a period of not less than 10 years from the date of its first discovery. The grant of marginal fields involved a farmout by the IOCs to local oil companies (Amaza et al., 2017). A federal government decree (No. 23 of 1996) awarded powers to the 'Head of State' to classify a field as marginal and to farm it out (Adetoba, 2012). Nigeria held its first marginal fields licensing round in 2001 with limited success; a second was attempted in 2013, but this was not followed through.

Amongst OECD countries, the *UK* adopted a comprehensive strategy on maximising economic recovery from oil and gas fields following the Wood Review in 2014. The 'MER UK Strategy' aims at establishing a regulatory regime which ensures that economic recovery of oil and gas is maximised through effective industry collaboration, exploration, and production (OGA, 2016).

Although *US* federal lease auctions are awarded primarily on the basis of cash bonuses, tracts are classified as wildcat (unexplored), drainage (adjacent to producing tracts), or developmental. Of these,

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[30] Discussed further later on in this section.

[31] In 2001, Mexico adopted 'Multiple Service Contracts' which permitted the limited use of private sector services. These did not need Constitutional reform and were awarded through public bidding, with companies required to fulfil technical and financial standards. Contracts were awarded for 20 years.

[32] To BHP Billiton.

[33] National Regulatory Agency for Petroleum, Natural Gas and Biofuel.

the latter are re-offerings of relinquished tracts or those previously held by companies where no exploratory drilling was done.

International experience thus suggests that there are several policy options to be considered in India's efforts to enhance production within a constrained timeframe. We set these out below.

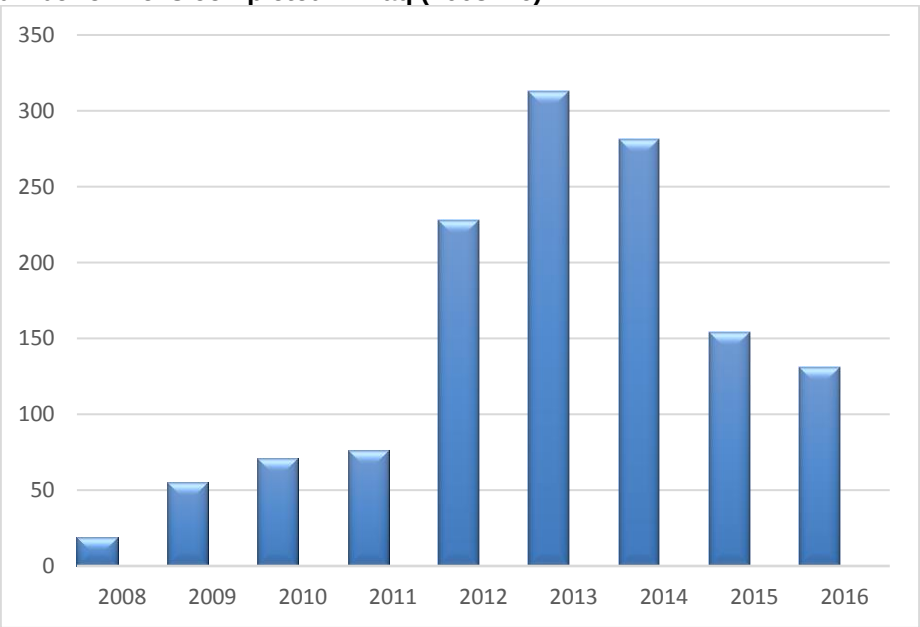
## 3.1 Production enhancement could be tied to a clear medium-term objective

The literature on resource tax design highlights the different objectives underpinning any fiscal regime. Mommer (2001) argues that regimes based on gross income ('proprietorial') constitute a payment to the property owner (ground rent) and are based on the premise that a company has a licence, which it uses to explore/produce, with a payment due irrespective of whether any profit is made, and of the level and rate of production. By contrast, in a 'liberal' fiscal regime, fiscal levies are imposed on net income and the objective is to permit companies to extract and produce at socially desirable levels and rates. Liberal fiscal regimes based on net income require robust oversight structures. Modern fiscal regimes combine instruments to achieve elements of both, but in principle there is arguably a trade-off. In microeconomic terms, this trade-off is between maximising revenues for the seller (government or NOC) and maximising the total gains to trade (for the government, NOC, and private companies). The extent to which the trade-off can be managed *ex ante* depends to an extent on two conditions:

- the prospectivity of a country (in other words, companies may be more willing to accept proprietorial regimes in resource-rich countries),
- the institutional structures in place to manage resource revenues (in order to mitigate information asymmetry in revenue assessment).

Where either of these two conditions is not strongly met, a statement of the objective of a specific bidding round or fiscal framework can help towards establishing clarity of expectations *ex ante*. We set out examples below.

**Figure 6: Number of wells completed in Iraq (2008–16)**




Source: OPEC Statistical Bulletin (2017)

*Iraq's* TSC rounds were clearly linked to a longer-term production target – set at an ambitious 13 mb/d when it originally signed TSCs in 2009, six years after the US invasion (IMF, 2015). This was later pared down.[34] Production has ramped up significantly, going from around 2.43 mb/d in 2008 to 4.47 mb/d in 2016 (BP, 2017). By 2017, Iraq's southern TSCs had collectively added roughly 2.3 mb/d of production since 2009, with 70 per cent of this representing growth and 30 per cent offsetting baseline decline (Addison, 2017). However, production has been considerably short of an ambition to achieve a cumulative Plateau Production Target in the TSCs of 8 mb/d; the TSCs effectively only achieved a third of the increment required to meet the target (Addison, 2017). Alsaadi (2017) states that the TSCs only began to have an effect after 2011, with the number of wells increasing by a factor of about four from 2011 to 2014, as a result of well completion in combination with a successful debottlenecking and rehabilitation effort (to improve the country's oil and water handling infrastructure) (Figure 6 above).

*Mexico's* 2008 Energy Reforms proposed to permit private sector participation, to manage the decline in existing fields and extend production through recovery techniques. The first round of ISCs[35] was held in 2011 for three southern 'mature' fields – Santuario, Carrizo, and Magallanes – holding an estimated 182 million barrels of proven, probable, and possible reserves. Production at the time totalled 14,000 b/d, but Pemex hoped that the application of EOR techniques and new investment could raise output to 55,000–70,000 b/d over three years (IHS, 2011). Similarly, through farmouts, Pemex expects its output to grow by 15 per cent over the next five years – approximately 200 kb/d – taking production up to 2.19 mb/d from around 2 mb/d (at the end of Q1, 2017). Lara (2017) sees this as optimistic, expecting production to increase no earlier than by 2025; however, the expertise obtained by Pemex through joint ventures could help in selecting future fields to develop, as well as in negotiating favourable terms with future partners. Sandrea and Sandrea (2017) see significant potential for farmouts to increase the recovery factor in mature fields, arguing that EOR capex is now competitive with exploration Finding and Development (F&D) costs. While F&D costs doubled from roughly $11 to $22/barrel between the 1990s to the present, capex requirements for EOR are in the range of $3–$15/barrel of fresh reserves.

In *Brazil*, one of the original objectives of upstream reforms in the late 1990s was to achieve 'self-sufficiency' in oil and gas, and although oil production briefly matched domestic oil consumption between 2010 and 2011 (Figure 7), this was not sustained due to several factors. Brazil's bid rounds have not occurred on a regular basis since 1997 – a five-year hiatus after the ninth round in 2008[36] led to serious lags in upstream activity. Combined with political turmoil[37] in the 2010s and falling oil prices in 2014, this negatively impacted upstream activity, prompting the upstream agency ANP to significantly accelerate its plans to bid out acreage. This declining production trend appeared to have reversed in 2016 for oil, while in April 2017 a government official stated that the country was aiming to achieve self-sufficiency in natural gas production within five years (EIA, 2017b). Admittedly, most of the increases have come from Brazil's pre-salt reserves under the PSC regime, and not from the concessions regimes (including marginal accumulations) (EIA, 2017a). Producers have mainly targeted large, offshore, pre-salt oil deposits. Brazil's pre-salt oil production in 2016 reached a record 1.02 million b/d, surpassing the 2015 production level by 33 per cent.

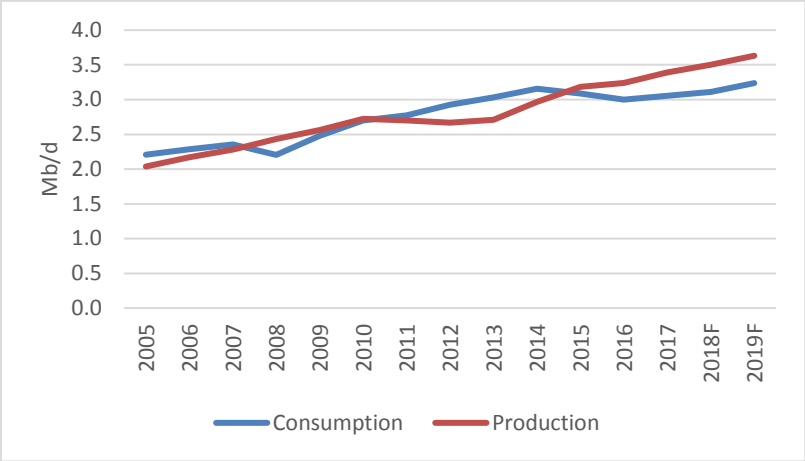
[34] Due to problems with the TSCs, discussed later in this section. The country is reportedly now pursuing a lower production target of 5.5–6 mb/d by 2020 (Reuters, 2016)

[35] Winners included Petrofac and Mexico's APC; as the latter failed to meet the 'financial security' requirement, the tender for its field (Carrizo) was awarded to Schlumberger (the second-highest bidder for that field) (Biller, 2011).

[36] The eighth round was also cancelled due to irregularities (see Almeida and Arruda, 2017).

[37] See Almeida and Arruda (2017).

**Figure 7: Brazil 'self-sufficiency' target in crude and liquids (mb/d)**




Source: EIA (2017b)

*Nigeria's* marginal fields policy similarly tied into several longer-term goals, which included increasing proved reserves to 40 billion barrels and boosting production levels to 4 mb/d (and in the process generating revenues for the state) (Oredein, 2013). Nigeria has suffered a prolonged decline in production, despite being an OPEC member. Production peaked at 2.4 mb/d in 2005, declining to 1.8 mb/d by 2009, picking up to just over 2 mb/d in 2010. Since then, however, production has declined to around 1.4 mb/d as of 2016 (OPEC Statistical Bulletin, 2017). The Nigerian National Petroleum Company (NNPC) reportedly set a 10-year timeframe for 'indigenous' oil and gas companies to increase their production from 10 to 50 per cent of national production (SCR, 2017). The objectives of the government in awarding marginal fields included (Osahon, 2013):

- increase production capacity through accelerated development of discovered reserves;
- provide alternative sources of funding for exploitation of hydrocarbon resources;
- increase the oil and gas reserves base;
- encourage capital inflow.

The *UK's* MER Strategy similarly aims to deliver 3–4 bboe over 20 years, with gross revenues of £200 billion (undiscounted) to the UK economy (Wood Review, 2014). The contributions of various measures were as follows (OGA, 2016):

- an increased rate of exploration was expected to deliver 1–1.5 bboe;
- the application of EOR was expected to deliver an additional 0.5–1 bboe, ranging up to 6 bboe in a 'best case' scenario;
- the improved use of infrastructure was expected to deliver an additional 0.5–2 bboe;
- the postponement of decommissioning by five years was expected to deliver an additional 1 bboe.

The above examples convey the relevance and use of clear *ex ante* objectives in production enhancement policies. Clarity over expected incremental volumes which feed into national energy policy targets and timeframes can also provide a useful benchmark for assessing the policy's progress.

## 3.2 Clarity is needed on the types of bidders being targeted through auctions

International experience shows that the type of company that bids in acreage rounds and goes on to win licences can be a contributory factor in eventual success or failure. Different companies in the upstream sector (oil majors, independents, service companies, 'new' or local entrants to the oil and gas

sector) have different underpinning business models – this is arguably likely to influence their incentives to produce and develop fields differently.

For instance, *Mexico's* ISCs (based on the 2008 reform) were bid out based on a fee per barrel of incremental production ($/boe) – for which the government fixed an upper ceiling akin to a 'reserve price'– with the lowest bidder winning the contract. Bidders also had to propose the percentage increment to the value of the field's production that would be added through investing in recovery techniques. Contracts were for 25 years, with a two-year evaluation period during which a minimum expenditure[38] had to be made by the winning contractor, followed by a development period over the remainder of the contract. The development period began only upon a declaration of viability by the contractor and approval of a development plan by Pemex-Exploración y Producción (PEP) – Pemex's tendering entity. Following two rounds, in 2011 and 2012,[39] Pemex's Board approved a third round of ISCs for the Chincontepec Basin in October 2012. The third round extended the scope of the contract to exploration, and was originally tendered in July 2013, but had to be retendered in October 2013 because the bids originally received were thought to be too low to incentivise higher production. For instance, in comparison with a maximum fee per barrel of $6.50 (set by Pemex), the lowest bids included ones from Halliburton ($0.01/bbl), Weatherford ($0.98/bbl), and Baker Hughes ($0.49/bbl). One argument was that the lowest bids came from service companies; these companies did not entirely depend upon production for their revenues, instead earning margins from providing oilfield services and optimising their existing infrastructure in the region. In contrast, oil exploration companies, including Moncolova Pirineos ($3.85/bbl) and Andes Energia ($4.94/bbl), would have to hire out all their services. Service companies and other operators were therefore potentially bidding on different things during the Chicontepec round; while the incentive for some operators was to produce the maximum amount of oil, the incentive for service companies was to 'work as much as possible' (Fredrick, 2013a; 2013b).

Production enhancement through the tendering of marginal fields to local companies has faced similar issues in *Nigeria*. Despite the first marginal fields round having attracted several Nigerian independents, with the government awarding 24 marginal field licences in 2003 (the farmors included Shell, Chevron, and Elf) to nine companies (farmees), only nine fields entered the production phase, reportedly producing 60 kb/d of oil, and doubling their proven reserves from roughly 141 million barrels to 303 million barrels (Osahon, 2013). In 2013, marginal fields accounted for 2.1 per cent of total production (Osahon, 2013). One of the biggest hurdles to the success of the round was the lack of winning bidders' access to finances for development.[40] The estimate of investment required to develop marginal fields in the 2001 round was $1–$1.7 billion, of which farmees were responsible for 40 per cent. Energy Mix Report (2014) describes a key obstacle being that most local banks did not extend loans to marginal field operators for putting fields into production; many insisting that the problem with funding the development of marginal fields was that the only asset available as collateral was the marginal field itself. They also insisted that if a marginal field operator had cash flow from other oilfield operations, other businesses, or a sizeable deposit with the bank, then these could be leveraged to approve loan facilities. Marginal field operators, on the other hand, argued that deposits to banks could only accrue if they were assisted in producing their fields. Bankers further argued that the best way to fund marginal field projects should be through equity contributions. This impasse stalled the development of the fields.

The *US* experience demonstrates some solutions to financing issues typically faced in non-OECD countries – through recourse to alternative modes such as private equity capital. Since the oil price fall in mid-2014, private equity investors have committed $200 billion to energy-focused private equity funds

[38] This was set at $112 mn in the first round (Mueller, 2011). Initial work obligations were $25–$50 mn in the second round.

[39] The second round was tendered in January 2012 for 22 fields grouped into 6 blocks in Mexico's northern production zone: Altamira, Pánuco, San Andrés, Tierra Blanca, Arenque, and Atún – two of which were offshore blocks (Samples and Vittor, 2012).

[40] Other hurdles included lack of access to technical expertise and to infrastructure, the relative marginality of the fields compared with the amount of investment needed to develop them, and the failure of the government to pass promised legislation – a Petroleum Industry Bill – creating uncertainties around future regulation (Energy Mix Report, 2014).

(WSJ, 2017). In Q1 2017, private equity companies and funds invested around $20 billion into the US shale sector, even as many companies had filed for bankruptcy in Q1 2016 (WSJ, 2017). Indeed, one argument is that shale oil companies have been able to 'bounce back' quickly and build on efficiency and technology gains, as their access to private equity capital frees them from traditional debt-related financing constraints – this has also placed them at the forefront of technological innovation. US oil import dependency consequently fell from a peak of 67 per cent of consumption in 2005, to 35 per cent in 2016. Sandrea (2014) attributes the rise in US shale supply to four broad factors:

(1) global oil price increases;
(2) the drilling of a large number of wells, along with technological advancements in horizontal drilling and hydraulic fracturing;
(3) capital and credit availability in the USA;
(4) the rise in political risk in many other countries and limited prospects outside the USA.

The above examples, and India's own past experience, suggest that providing clarity in the policy over the types of bidders that the government wishes to attract, in order to meet a clearly stated medium to long-term production-enhancement objective, can help pre-empt some of the delays and failures seen in bidding rounds across the world, and also emulate some of the successes.

## 3.3 Bidder qualification criteria could be designed to consider past experience

As discussed earlier in this Insight, economic efficiency in the capture of rent can, in theory, be achieved at the outset by selecting the most efficient operator to extract resources in the long-run. *Nigeria's* experience with production enhancement through marginal fields rounds provides a good illustration of two common hurdles which preclude the successful fulfilment of work programmes after the conclusion of bidding rounds and the awarding of licences. The first, as discussed above, is that the smaller (often 'indigenous') companies that are targeted in the rounds, having won licences, do not have access to the requisite capital to develop the fields. The second hurdle, also reported as contributing to the failure of Nigeria's marginal fields rounds, is the inability of marginal operators to attract appropriate technical expertise (Energy Mix Report, 2014).

The Nigerian government attempted to resolve these issues in the second marginal fields bidding round by encouraging partnerships between indigenous and foreign companies. The second round included 31 marginal oil fields – 16 onshore and 15 on the continental shelf of the country's Niger Delta. Companies eligible to participate needed to be 51 per cent owned by Nigerian citizens; no single bidder could hold more than a 25 per cent participating interest – although the Department of Petroleum Resources (DPR) later clarified that a foreign technical partner could hold up to 49 per cent through a Nigerian registered company (Dentons, 2014). Bidders needed to demonstrate upstream oil and gas experience and the technical capability to evaluate and develop the asset. The bidding round was to be conducted in four stages – pre-qualification, technical and commercial tender, oral presentation, and announcement of winners. Bids had to include details of bidders' financial and technical competencies and their work programmes, and they were screened by a selection committee comprised of the DPR, the Nigerian National Petroleum Company (NNPC), and the operator (farmor). Despite these reforms, the second round was never concluded. Consequently, the average annual rate of production decline has been just under 1 per cent in the period 2005–15 (BP, 2017), accompanied by a fall in the number of producing wells. The reserve base has remained relatively static at 37.2 billion barrels since 2006 (BP, 2017).

*Brazil's* experience, in contrast, provides a useful illustration on designing bidder qualification criteria. The procedure for awarding contracts under the fourth round for marginal accumulations included the following steps (ANP, 2017a; 2017b): bidders first register with a specially constituted bidding commission – CEL – and submit financial guarantees/bid bonds to participate in the rounds. Bidders then present their offers in a public forum; bids are assessed in descending order, and the signature bonus of the offer is the main variable used to identify winning bidders. This step does not, however,

guarantee the signing of concessions contracts. Bidders are then required to submit documentary evidence that they satisfy the qualification criteria for the tender on the basis of three main parameters:

(i) legal regularity of tax and labour;
(ii) economic and financial capacity;
(iii) technical capacity.

This process is overseen by a superintending authority, and bidders' qualifications are judged by CEL. Finally, winning bidders that do not meet the qualification criteria are subject to a penalty (applied to the guarantees submitted whilst applying to participate in the rounds). Those which do, go on to sign contracts with ANP.

**Table 4: Qualification criteria for Brazil's fourth marginal accumulations round (2017)**

| Qualification | Legal | Technical | Economic & Financial | Operating Environment |
|---|---|---|---|---|
| Operator A | Compliance with tax & labour laws | 81 points or more | R$122 mn | Ultra-deepwater, deepwater, shallow water, onland, marginal |
| Operator B | Compliance with tax & labour laws | 30–80 points | R$67 mn | Shallow water, onland, marginal |
| Operator C | Compliance with tax & labour laws | 2–29 points | R$4.5 mn | Onland, marginal |
| Operator D | Compliance with tax & labour laws | E&P professional with at least 2 years' experience | R$700,000 | Marginal blocks |
| Non-Operator | Compliance with tax & labour laws | Summary of its main activity | 50% of operator PLM | Can only submit offers in consortiums |

Source: ANP (2017b)

Brazil's ANP has defined specific accreditation (qualification) criteria for operators wishing to bid in the rounds, according to the degree of difficulty of the area to be licensed, thus allowing the participation of different types of companies, as well as the financial participation of non-operators (Tordo et al. 2009) (See Table 4). This also helps narrow down the type of companies that the government wishes to attract in bidding rounds for different geologies.

- *'Legal qualification'* requires contractors to demonstrate compliance with tax and labour laws.
- *'Economic and financial qualification'* require contractors to demonstrate that the equity they have available is equivalent to or greater than the minimum equity required for the 'operational environment' in which they wish to carry out upstream activities (ANP, 2017b).
- *'Technical qualification'* criteria classify operators into one of five categories based on their ability to operate in blocks located in deep water, shallow water, on land, in areas with marginal accumulations, and as part of bidding consortia.
- Points for *'technical* criteria' are awarded on the basis of four main aspects:
    - prior experience in E & P activities;
    - length (of time) of experience in E & P activities;
    - volume of production in the last five years;
    - amount of investments in exploration in the last five years.

An important element of technical accreditation by ANP is that it considers the technical experience of individual technical staff or senior-level management in the potential contractor's organisation, especially when any of the other three technical criteria are not met (Table 5).

This form of accreditation extends the scope of technical qualification beyond institutional capacity and its associated efficiency constraints.[41] In many countries, skilled labour is fairly fluid in the upstream industry – for instance, the movement of skilled personnel between firms in the US upstream industry and its 'nimble' labour market, offers a recent example, and this has fed into the resilience of the US shale industry (IMF, 2015). Alternative financing structures, that are different to 'conventional' players (for instance, private equity-backed energy companies in the US which have access to a 'pool' of capital), could be similarly accounted for within accreditation criteria.

**Table 5: Technical qualification scores based on experience of technical staff**

| | **Time of experience (T) in years** | | |
|---|---|---|---|
| | **2<=T<=5** | **5<=T<=10** | **T>=10** |
| Exploration land | 3 | 5 | 7 |
| Production land | 3 | 5 | 7 |
| Exploration shallow water | 3 | 5 | 7 |
| Production shallow water | 3 | 5 | 7 |
| Exploration deep/ultra deep water | 3 | 5 | 7 |
| Production deep/ultra deep water | 3 | 5 | 7 |
| Operation in harsh environments | 3 | 5 | 7 |
| Operation in environmentally sensitive areas | 3 | 5 | 7 |

Source: ANP (2017b)

The above examples therefore provide policy options for designing bidder selection criteria *ex ante*, in order to pre-empt problems with the fulfilment of work programmes after bids have been awarded.

## 3.4 Bidding criteria should be designed to minimise opportunities for 'gaming'

Past experience suggests that given India's regulatory oversight capacity, the greater the number of biddable variables and the more complex the fiscal framework, the higher the probability of 'gaming'. While bidder selection criteria can curb this to some extent, the bid criteria and fiscal terms should ideally be simple to assess and easy to administer, while minimising economic inefficiency and garnering broad political acceptability. Some desirable characteristics of bid criteria are:

- they should ideally be structured to result in a single assessable score;
- they should allow for adjustment of the relative importance (weights) placed on each criterion;

Nakhle (2015) states that most important biddable parameter is the investor's work commitment, specified in both physical terms and financial expenditure terms. Further, a prerequisite for the selection of the work program as the biddable parameter is to have a highly qualified and skilled committee to evaluate the bid, in order to minimize the risk of overcapitalization and ensure the most efficient extraction of the resource.

[41] Arguably, state-owned companies may be subject to different operational constraints than those in the private sector; this is reflected in different discount rates.

*Iraq* and *Iran* are countries which have experience with designing TSCs. We refer to their experiences below as a general illustration, although it must be noted that given their unique characteristics few countries can be directly compared to them.

In *Iraq*, the first three rounds for TSCs included two biddable criteria:

- a Remuneration Fee (RF) in dollars per barrel of oil equivalent;
- a Plateau Production Target (PPT) in barrels of oil (or Million Standard cubic metres of gas) per day.

The criteria targeted bidders who proposed the lowest remuneration fees per barrel (RFBs) and highest plateau production targets.[42] The minimum acceptable values for a number of parameters – including the expected baseline production levels and expected expenditure obligations – were set out in Final Tender Protocols. Iraq's Ministry of Oil stipulated that it would accept the highest scoring bidder, provided that the high scorer did not exceed an undisclosed maximum RFB. In the event of a single high scorer for a licence, the latter would be invited to revise its RFB down to the maximum RFB, which was then made public. In the event of a tie, the tied bidders were invited to re-submit revised bids, but the PPTs could not be revised downward, or RFBs revised upward. In the case of a tie between a consortium and a single company, the former would be awarded the bid. Bidders were also required to submit a bid bond and pay a pre-defined signature bonus, which was recoverable through 'supplementary fees'[43] over five years. Iraq's TSCs allowed contractors to recover costs through 'service fees', which were payable through 50 per cent of a contract area's revenues attributable to incremental production over the baseline production level. 'Supplementary fees' were then payable from a proportion[44] of the remaining revenue from a contract area (Final Tender Protocol, 2009). The RFB was only paid if production exceeded a minimum targeted level. The applicable fee per barrel was also adjusted according to the stage of the FOC's cost recovery in the TSC, simulated by an R-Factor. In the early stages of the contract, as the R-Factor was less than 1, the applicable fee per barrel was the same as the RFB. However, as the R-Factor increased (and the contractor recovered its costs), the RFB accordingly adjusted downwards (see Table 6).

**Table 6: R-Factor Adjusted Remuneration Fee Per Barrel (RFB) in Iraq**

| R-Factor | RFB ($/bbl) |
|---|---|
| < 1 | 100% |
| 1.0 to less than 1.25 | 80% |
| 1.25 to less than 1.5 | 60% |
| 1.5 to less than 2.0 | 50% |
| 2.0 and above | 30% |

Source: Final Tender Protocol (2009)

A critique of an early draft of Iraq's TSC in Van Meurs (2009) highlights potential concerns with the bidding criteria and fiscal terms. It recommended permitting the recovery of a fixed percentage of capital and operating costs, rather than the full cost, which would force bidders to bid correspondingly higher incremental remuneration fees – in turn providing a stronger incentive to achieve higher production. It also highlighted the distorting incentive provided to contractors by the R-Factor (adopted primarily to prevent 'windfall profits' to FOCs) to 'gold-plate' their expenditures. If the contractor had higher expenditures, the R-Factor would be lower and hence the applicable fee per barrel would remain higher. In other words, a costlier project would result in a higher remuneration to the contractor. Van Meurs

[42] Plateau production was deemed to have been achieved if the production level was maintained for 30 consecutive days; the time to achieving plateau production was stipulated in the contract and could continue for a period of 7 years (Ghandi and Lin, 2014).
[43] These were non-petroleum costs.
[44] Ghandi and Lin (2014) put this at 10%.

(2009) therefore recommended scrapping the link to the R-Factor altogether and maintaining a fixed incremental remuneration fee, alongside introducing other measures to avoid windfall profits.

Iraq's TSCs have run into problems that are largely linked to the oil price downturn in mid-2014,[45] which affected the government's ability to make timely payments on remuneration to FOCs as their oil export revenues – the backbone of the country's finances – also declined. Many FOCs voiced concerns over inefficient procedures for field development approvals and for signing off on contracts to advance projects. These were reportedly addressed by the Ministry of Oil in a decree on 'Facilitation and Simplification of Procedures on Oil Projects Execution' that was approved by Iraq's cabinet in 2015 (IMF, 2015). In 2016, Iraq published a tender for 12 small and midsize fields, which were to be awarded on the basis of bilateral negotiations between the oil ministry and 19 pre-qualified oil companies, moving closer to a PSC model in which FOCs received a percentage of the output, instead of a fixed fee per barrel (Reuters, 2016).

*Iran's* old buyback contracts provide another example. These were services contracts under which a foreign company developed an oil or gas resource and was repaid from sales revenues but had no share in the project's profit. Upon first production, the investment was handed over to the National Iranian Oil Company (NIOC) or its representative, which would operate and manage it. The IOC received remuneration for its services namely: engineering, procurement, and construction, together with the financing thereof, and the transfer of technology. Payments began after development was completed and products became available for marketing. The remuneration fee in dollars per barrel was the main biddable parameter. The main constraint in buyback contracts was that all variables (such as production, capital cost ceiling, and a contractual real oil price of $15/barrel) were fixed *ex ante*, allowing for little flexibility to respond to either exogenous or endogenous changes. Perhaps because of this rigidity, Li et al. (2017) state that Wood Mackenzie reported in 2015 that only one of eight buybacks had reached its expected Rates of Return (RORs). Most western IOCs exited Iran following US sanctions and since 2009 only two Chinese oil companies have remained investors in Iran's upstream sector – one was suspended and one terminated due to a slowdown in activity (Li et al, 2017).

In 2015, following the Joint Comprehensive Plan of Action (JCPOA),[46] Iran revealed the Iran Petroleum Contract (IPC) – targeting investments of $185 billion and an increase in production levels of 2 mb/d (Platts 2016). The IPC focuses on enhancing production from mature fields and contains measures which presumably address some of the deficiencies – particularly with incentivising production – in the old buybacks (Dentons, 2016). It establishes a base fee per barrel linked to market prices (instead of an *ex ante* threshold price). Base fees are subject to additional multipliers per barrel (or per mcf of gas) to incentivise exploration of high-risk contract areas (ranging from 1× for low-risk fields through to 1.5× for high-risk onshore/offshore single or unitised fields). A separate fee multiplier applies to brownfield sites (or greenfield sites to which EOR techniques have been applied), designed to reward incremental production increases, again acting as a multiplier to the volumetric base fee (1.2× at the low end for increases of up to 20,000 b/d and increasing in bands up to a maximum of 1.5× where production increases by more than 100,000 b/d). The fixed fee has therefore been replaced by a volumetric fee.

Based on the above examples, an illustration of a simple point bid assessment criterion for a typical production-enhancement contract is as follows:

$$\boldsymbol{Bid\ Score} = [\boldsymbol{M_{PE}} * \boldsymbol{W_1}] - [\boldsymbol{M_{RF}} * \boldsymbol{W_2}]$$

Where, $M_{PE}$ constitutes some measure of investments committed to enhance production, or to enhanced production levels; $W_1$ represents the weight assigned to this criterion; $M_{RF}$ constitutes some measure of contractor remuneration (which could be a fee, an equity share, or additional royalties, for instance); and $W_2$ represents the weight assigned to this criterion. The weights could, if necessary, also

[45] See 3.8 below on exogenous changes.
[46] Which ended western sanctions against Iran.

be replaced with formulae.[47] Potential bidders would have the incentive to bid a higher $M_{PE}$ and a lower $M_{RF}$ to win the contract. Both criteria could have undisclosed reserve prices (predetermined lower and upper limits). Volumetric multipliers to the base fee could provide incentives to achieve or beat production targets. (Appendix 1 summarises the bid criteria and fiscal terms from the examples discussed in this paper.)

## 3.5 The fiscal framework should be structured to closely align the interests of parties to the contract

International experience has shown that problems tend to arise from production-enhancement contracts when the contractor's incentives, and therefore the time value placed on money, are different from those of the licence holder (the NOC, for example).

*Iran's* experience provides some general insights. Iran's buy-back contract had four main components (Groenendaal and Mazraati, 2006):

- It stipulated, *ex ante*, the annual capital expenditure over an investment period. IOCs were given two years after the start of the contract to determine the capital expenditure level.
- Bank charges on the amount of investment had to be paid by the IOC. The interest rate was based on the London Inter Bank Offer Rate (LIBOR) plus a premium of up to 1 per cent; these charges were not recoverable from revenues.
- The IOC could recover the costs of its investment once production commenced, subject to a percentage cap in each period.
- Fourth, remuneration in $/barrel was paid to the IOC for its services; payments began after the development of the field was completed and products became available for marketing.

In addition a buyback contract contained an agreed upon internal rate of return (ROR) for the IOC, subject to negotiation with NIOC, but usually set between 12 and 15 per cent. As mentioned earlier, the main constraint in a buyback contract was that all variables were fixed *ex ante*. Changes in any of the variables could therefore lead to a lower rate of return for the IOC, as *ex post* adjustments were not permitted, and the regime did not allow for progressivity in the fiscal terms. Groenendaal and Mazraati (2006) summarise the main risks to the contractor or IOC under buyback contracts as follows: oil prices fall below the agreed upon threshold; capital expenditures rise above what was agreed (capital cost over-runs); delays in construction; production profile below the expected baseline; cut in production due to accidents; and, higher than expected operation and maintenance costs.

These risks incentivised contractors to complete projects within deadline, but also created distortions. For instance, a delay in construction would lead to a later revenue stream, and the IOC would have to bear the associated bank charges (which were not recoverable from revenues); this effectively acted as a penalty to stem inefficiency. However, as the payment period began after production commenced, and the field operations were then taken over by NIOC, the payment schedule was entirely contingent upon NIOC optimising field operations. Similarly, repayments to the IOC could be postponed if oil prices dropped below the agreed upon threshold rate (a real oil price of $15/barrel). Iran's IPC presumably attempts to redress the balance of incentives. During exploration, the IOC acts as operator and retains control over day-to-day issues, but control over a number of operational issues is escalated to the Joint Exploration Committee (JEC), comprising equal members of both the IOC and NIOC. During development and production, operations are implemented through a 'contractor' JV company, and major decision making is assigned to a joint steering committee (the JSC) with equal representation for NIOC and the IOC, with annual chairmanship alternating between NIOC and the IOC. In January 2017,

[47] Based on Van Meurs (2009).

Iran prequalified 29 companies to bid under the first round using the IPC. However, the round has been repeatedly postponed pending approval of the new IPC from the country's higher authorities.

An option for aligning the interests of the contractor and the NOC is to assign participating interest (equity) in fields that would benefit from the application of production enhancement techniques by the contractor and bringing both parties to the contract onto the 'same page' with regards to the time value of money (thus aligning their objectives). We discuss this further in 3.6 below.

## 3.6 Previous efforts undertaken by NOCs need to be taken into consideration in blocks designated for farmouts

International experience shows the central historical role of the NOC in the development of the national oil industries of many countries. Most decisions to farm out acreage in these countries have been undertaken to relieve financial pressures on the NOCs – whose revenues are often utilised to meet the government's social expenditure, to revive upstream activity and development of areas hitherto considered to be 'marginal' to the NOC's operations, and to 'farm in' the technologies and investments needed for enhanced recovery. Several countries have chosen to undertake this route. The majority of Nigeria's production comes from *Unincorporated Joint Ventures* between the NNPC and the major IOCs, under a PSC regime. NNPC retains a majority stake (averaging 60 per cent) in these ventures, in alignment with state sovereignty over hydrocarbon resources (Amaza et al., 2017).

In *Mexico*, Pemex provides two thirds of the Mexican government's tax revenues, which are utilised to finance state expenditure; additionally, it is a major state-sector employer (Samples and Vittor (2012) estimated that Pemex employed roughly 140,000 people). Multiple pressures on Pemex became evident after 2004, when production peaked at 3.8 mb/d, thereafter declining to 3.2 mb/d by 2008 (BP, 2017). Production was sustained for several years despite these constraints, due to output flowing from the 'supergiant' Cantarell field. However, Cantarell went from producing 63 per cent of Mexico's oil output in 2004, to just 17 per cent by 2013. The 2008 reforms failed to reverse the production decline and production decreased by an average annual rate of 3.7 per cent from 2005 to 2015 (BP, 2017). Reserve replacement has been below 100 per cent for the last decade and Pemex has suffered high decline rates from mature fields that comprise more than 80 per cent of its active assets (Vielma, 2017). Vielma (2017) estimates that falling oil production led to a drop of more than 20 per cent in state revenues between 2006 and 2016. Alarcon (2017) estimates that between 1993 and 2014, Pemex gave 110 per cent of its profits to the Mexican state and had to increase its debt just to pay taxes.

Mexico's 2013 Energy Reform aimed, among other things, to:

- maintain state ownership of hydrocarbons within the subsoil whilst allowing companies to report the expected economic benefits from contracts for accounting and financial purposes;
- create four types of contracts for exploration and production:
    - service contracts (companies paid for activities done on behalf of the state),
    - profit-sharing contracts,
    - production-sharing contracts,
    - licences (royalty/tax regimes);
- transform Pemex into a '*state productive enterprise*' with an autonomous budget.

Farmouts of Pemex's acreage were seen as a key component of the reforms. The two main fiscal terms and bid criteria for farmouts included an additional royalty over the base royalty[48] and an 'additional contribution' for the field (Pemex, 2016) – 10 per cent of which was required to be paid upfront as a signature bonus. It was assumed that only bidders with the highest reputation and experience would

[48] Bids for this were subject to a floor and ceiling – for the Trion farmout these were 3% and 4%.

have the financial backing to meet high signing bonuses (Rinkenbach, 2017).[49] The amount also accounts for the 'carry' or investment made on behalf of the partner. The additional contribution is used as a tie breaker.

In the *Trion deepwater farmout*, Pemex released 60 per cent of its participating interest in the project as part of the contract. The winning bidder, BHP Billiton, offered an additional royalty of 4 per cent over the base royalty of 7.5 per cent. It also offered the highest additional contribution of $624 million, above the established minimum contribution of $570 million. The expected investments amount to $11 billion, with initial production expected by 2023 and plateau production achieved by 2025 (Pemex, 2016). For farmouts of the *two mature onshore fields*, Germany's DEA Deutsche Erdoel AG won the Ogarrio farmout with an offer for an additional royalty of 13 per cent and a cash payment of $213.9 million (Buchanan, 2017). The Cardenas-Mora farmout was awarded to Cheiron Holdings Ltd. of Egypt with an additional royalty of 13 per cent and $41.5 million in cash, in addition to a $125 million carry to compensate for development already done in the block by Pemex (Buchanan, 2017). Pemex released 50 per cent of its participating interest to the winning bidders in each of the fields. Pemex expects production to increase by 30 per cent in each field over the next few years (Buchanan, 2017).

Mexico began its reform by holding 'Round Zero' (results announced in August 2014), in which Pemex could request probable and prospective reserve areas that it wanted to retain as a part of its portfolio, and which would be a key determinant of its future performance (CRS, 2015; Alarcon, 2017). It was granted 83 per cent of Mexico's probable reserves and 21 per cent of prospective reserves (CRS, 2015).[50] The main criticism of the Pemex farmouts has been that in Round Zero, Pemex was deprived of having 'a solid material basis' that could allow it to become a dominant player within Mexico's new institutional framework. The Mexican Congress directed the energy ministry to compensate Pemex for the 'fair economic value' of investments made over the years in areas and fields that it did not retain after Round Zero. The reasoning was that as a result of many of those investments, Pemex had added reserves (or at least reduced the geological risk) and production to the country and had also developed associated infrastructure. Alarcon (2017) argues that the energy ministry interpreted the Congress directive to mean that Pemex should be compensated for those areas it had requested in Round Zero but which it did not receive. Alarcon (2017) further argues that the Pemex farmouts have failed to recognise the value of investments already made by Pemex in areas which have been bid out to private companies, that compensation to Pemex for these investments has been long delayed by the Mexican government, and that the valuation of these investments by the government has been entirely inadequate (for instance, while Pemex initially put the value of such investments at $4 billion, government assessments put it at as low as $300 million). The reforms have been critiqued as a 'missed opportunity', highlighting the need to recognise the central role of the NOC in oil sector development (Alarcon, 2017). Despite the recently cancelled second farmout, some industry observers have argued in favour of the potential for using farmouts to prolong the lives of Mexico's mature, marginal fields, some of which have recovery factors as low as 18 per cent (Sandrea and Sandrea, 2017).

Experience has shown the necessity of recognising and compensating the investments already made by NOCs in areas designated for farmouts. One method of compensation is for a potential contractor to add a 'carry' (as part of a cash or signature bonus, for example) reflecting the fair economic value of development already done in the field or block – determined, for instance, by the regulator – in return for the NOC releasing a percentage of its participating interest. Another method would be to give the NOC the option to 'back-in' to the field or block at a later date. A third option would be for the transfer of interest in the block to occur after the fulfilment of obligations matching the fair economic value of investments made by the NOC, effectively bringing both parties in the contract onto an even playing field.

[49] The bonuses were also used to prevent speculative bidding (Rinkenbach, 2017).
[50] Pemex originally requested 31% of prospective reserves (CRS, 2015).

## 3.7 Clarity should be provided on the rules of access to infrastructure

In mature areas, third-party access to infrastructure is an important catalyst for the success of production-enhancement policies which involve either RSCs or farmouts, and ambiguity over ownership or use of the same can delay production. Third-party use of facilities creates an alternative to requiring the individual licence group to build its own infrastructure, thereby significantly lowering costs and rendering minor discoveries commercially profitable (Grondalen and Lower, 2016). For example, in *Nigeria's* marginal field rounds, the lack of access to infrastructure was identified as a contributory factor to the failure of marginal operators to increase production, and the DPR had to intervene to negotiate with multinational companies to share excess capacity or to lease or repair older facilities that were not in use (Adetoba, 2012). In mature provinces such as *Norway*, the use of existing infrastructure provides an essential instrument for the Norwegian authorities to ensure efficient resource management of the petroleum resources remaining on the Norwegian Continental Shelf (Grondalen and Lower, 2016). The UK's Maximising Economic Recovery (MER) policy similarly comprises several important elements which, in combination, are meant to enable the optimal use of infrastructure: *Asset Stewardship, Regional Development, Infrastructure,* and *Decommissioning* strategies.

- ***Asset Stewardship*** requires operators to develop, maintain, and operate their assets and infrastructure at all times in an efficient and effective manner and to share their asset stewardship strategy with the Regulator, which should set clear expectations on critical stewardship factors.
- ***Regional Development*** ensures the development of UKCS resources on a regional, rather than solely on a field, basis. Operators are required, where appropriate, to cooperate with the Regulator and other licence holders in the wider adjacent area on all aspects of field and cluster development, from exploration through to decommissioning, with the overarching aim of maximising economic recovery from clusters of fields as well as individual fields.
- ***Infrastructure*** comprises rules to govern third-party access to infrastructure. These are required to prevent owners from exercising substantial market power (which could cause output to fall below the socially desirable level in the long run).
- ***Decommissioning*** refers to a strategy aimed at achieving the maximum economic extension of field life and ensuring that key assets are not decommissioned prematurely to the detriment of production hubs and infrastructure.

## 3.8 The fiscal framework should be adaptable to exogenous changes

International experience has shown that exogenous changes – particularly those relating to oil price changes – can impede production-enhancement efforts by affecting both the contractor and government (or the NOC). This is specifically the case when the remuneration (the fee per barrel, for example) does not account for oil price fluctuations. For example, when oil prices fell in mid-2014, Iraq's government struggled to make remunerative payments under its TSCs due to its low export revenues, delaying payback. It eventually resorted to requesting contractors to deliberately reduce their capital spending on field development, which affected production targets. The government reportedly asked several FOCs to make downward adjustments to their PPTs – capital spending thus declined from $18 billion in 2015 to $10.7 billion in 2016, only rising marginally to $11.7 billion in 2017 (Alsaadi, 2017). Van Meurs (2009), in a critique of Iraq's TSCs, recommended indexing the RFB directly to the oil price. It argued that this would correct for impacts of inflation, ensuring that:

**a)** bidders were not given the incentive to bid initially relatively high fees (RFB) to cover the inflation risk;

**b)** it was not in the interests of the contractor to maximise production during the later years of the contract (thus delaying first production);

**c)** the regime would support a sustained flow of investment, providing that it was in alignment with the government's policy objectives to do so (investors may otherwise want to accelerate investments during periods of low prices and reduce them during periods of high prices).

Production-enhancement contract design could therefore incorporate a price indexation mechanism.

## 4. Conclusion

India's government is attempting to revive investments in its upstream sector, following several years of decline. These efforts are related to achieving a policy objective of reducing energy imports by 10 per cent over current levels by 2022. Following an auction of marginal fields held by its National Oil Companies (NOCs) in 2016, it launched an open acreage licensing round in 2017, changing the upstream fiscal regime from a profit-sharing to a revenue-sharing model. Given the proximity of the 2022 target, other models are being considered, including NOC farmouts and production-enhancement contracts. This paper has sought to contribute to the policy discussion by addressing the following questions: what are the lessons from India's previous bidding rounds for upstream acreage? And, what are some of the policy considerations, given similar international experience? The paper identified two concerns that have arisen from past experience: first, the setting of entry or qualification criteria at levels which encourage healthy participation in the bidding rounds, yet which ensure that those companies participating can deliver on their work programmes, should they go on to win. And second, the setting of biddable fiscal criteria that are relatively straightforward to assess, yet which do not provide perverse incentives for firms to modify their investment behavior away from what is optimal or in alignment with wider energy policy objectives. Based on international experience, the paper sets out several policy options for consideration, with the obvious proviso that what works for one country may not always work for another. A key message from the paper relates to the need for clarity over the types of companies which policymakers wish to attract to fulfil energy policy goals. At one end of the spectrum are large multinationals for whom scale of opportunity (in terms of the material impact on their businesses) is an important factor in upstream bidding. At the other end, the government could stimulate the industry in marginal fields by targeting smaller, specialized E&P companies, for whom the general business environment and operator flexibility are important factors. Finally, India's previous experience with upstream policy suggests that any optimal policy option needs to square three (sometimes conflicting) features: economic efficiency, administrative simplicity, and political acceptability.

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## Appendix I: Bid criteria and fiscal terms in production enhancement policies

| | Main Bid Criteria | Fiscal Terms |
|---|---|---|
| **Iraq TSCs** | ▪ Remuneration fee in $/barrel (RFB);<br>▪ Plateau Production Target in barrels of oil or Million Standard cubic metres of gas per day. | ▪ Bid bond;<br>▪ Pre-defined signature bonus (recoverable through supplementary fees);<br>▪ Costs could be recovered through service fees payable through 50% of contract area's revenues attributable to incremental production over the baseline;<br>▪ RFB payable to contractor;<br>▪ RFB adjusted according to stage of FOC's cost recovery in the TSC, determined by R-Factor. |
| **Iran buyback contracts** | ▪ Remuneration fee in $/barrel. | ▪ Remuneration fee payable to contractor after development complete and product available for marketing;<br>▪ Bank charges on amount of investment to be paid by IOC; interest rate based on LIBOR plus up to a 1% premium; not recoverable;<br>▪ Percentage cap on cost recovery after production commenced;<br>▪ Annual capital expenditure stipulated *ex ante*;<br>▪ Rate of Return for IOC agreed *ex ante* subject to negotiation with NIOC, usually set between 12% to 15%;<br>▪ *Ex ante* threshold oil price per barrel;<br>▪ New IPC proposes base remuneration fee linked to market prices and subject to additional multipliers per barrel for meeting or exceeding production targets;<br>▪ New IPC proposes an R-Factor mechanism to adjust fees based on level of production of the field and ratio of costs recovered against revenue earned. |
| **Mexico** | *ISCs*<br>▪ Fee per barrel of incremental production ($/barrel) subject to an upper ceiling (reserve price);<br>▪ Proposed percentage increment to the value of the field's production through investments in recovery techniques. | ▪ Minimum capital expenditure;<br>▪ Minimum percentage of local content;<br>▪ Cost recovery (capped at 75% in first round);<br>▪ R-Factor adjustment to fee per barrel from 100% down to 60% of full fee;<br>▪ 10% carried interest by Pemex;<br>▪ Performance-related bonus payments for exceeding targets;<br>▪ Income tax, but no VAT or royalties. |

| | | |
|---|---|---|
| | *Pemex farmouts*<br>▪ Additional royalty over base royalty;<br>▪ An 'additional contribution' for the field. 10% required to be paid upfront as a signature bonus. Also accounts for the 'carry' or investment made on behalf of the partner. | |
| **Brazil Concessions** | ▪ A Signing Bonus, weighted with 4 points in the total bid evaluation;<br>▪ a Minimum Exploration Program (PEM), also weighted with 4 points; and,<br>▪ Local Content,[51] weighted with 2 points, and divided into 0.5 for the exploratory phase and 1.5 for the development and production phase. | ▪ A cash Bonus;<br>▪ A 10% Royalty; reduced to 5% for marginal accumulations;<br>▪ A Landowners' Participation Fee, varying from 0.5 to 1%;<br>▪ A Special Petroleum Tax (SPT) levied on fields with high production levels or high profitability, and applied on the gross margin from production after the deduction of royalties, exploration investments, operational costs, depreciation, and taxes. SPT is capped at 40%;<br>▪ Corporate Income Tax, state and municipal taxes and a 'social contribution'; and,<br>▪ A Surface Rent per square kilometre. |
| **Nigeria Marginal Fields** | ▪ Participation fee of $28,000;<br>▪ Signature bonus of $300,000 payable up front by winning bidders;<br>▪ For proposed second round: details of bidders' financial and technical competencies, work programmes; screening by a selection committee comprised of the DPR, NNPC and Operator (farmor). | ▪ Contractors could not hold more than 40% of the participating interest;<br>▪ Contractors had to pay sliding scale royalties based on production levels to the government and farmor, as well as a reduced profit tax of 65% (from 85%) for the first 5 years. Proposed reduction to 55% for second marginal fields round (never concluded). |

[51] The government reduced local content requirements for the 4th marginal field round in 2017. See Simonsen Vogtwiig (2017).